Fort Hills Project Update
...Execution and Technology Success

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Using technology and innovation to deliver performance results

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Agenda...

- **Fort Hills Project**
  - Brief Review of a Long History
  - Hardware Build Overview

- **PFT Technology**
  - Processing Mined Bitumen

- **Marketing / Quality**
  - Quality vs existing SAGD Dilbits
  - Value and Life Cycle Analysis Principles
The Fort Hills oil sands mining project is located in Alberta’s Athabasca region, 90 kilometers north of Fort McMurray, Alberta and is recognized as one of the best undeveloped oil sands mining assets in the region.

The project’s co-owners are:
- Suncor Energy Inc (53.06%)
- Total E&P Canada (26.05%)
- Teck Resources (20.89%)

The project is operated by Suncor, has produced first oil and is ramping up production and plans to achieve 90% of its planned production capacity of 194,000 barrels per day in 2018. The mine life is expected to be approximately 50 years at the current planned production rate.

Fort Hills has created work for approximately 5,000 construction workers at the peak of construction and approximately 1,600 permanent positions for the mine and bitumen production facility when fully operational.

Fort Hills has been designed to utilize Suncor’s latest technology and approach to tailings management and reclamation processes. Suncor will closely monitor operations so existing and future water quality standards – and environmental requirements – can be met or exceeded throughout the life of this mine. The project will aim to return all disturbed lands to as close to a natural state as possible.

Fort Hills asset adds to Suncor regional existing synergies

Regional synergy opportunities

- Upgrader feedstock optionality
- Turnaround planning optimization
- Unplanned outage impact mitigations
- Process and technology sharing
- Sparing, warehousing and supply chain management
- Regional contracts (lodging, busing, flights, etc.)
- Lease development optimization

1 See Slide Notes and Advisories.
Suncor has been working on the project for the past 13 years, but the Fort Hills lease has actually been under development for almost a century. The project has been around the block several times.

Alberta's very first oil sands extraction plant was located on the Fort Hills lease. Dr. Karl Clark, inventor of the Clark Hot Water Process that separates bitumen from the oil sands, helped develop “Bitumount”, Alberta's first "commercial" oil sands plant built along the banks of the Athabasca River with the help of PEI entrepreneur R.C. Fitzsimmons in the late 1920s.

Dr. Clark passed away less than a year before Suncor started up its base plant operation in 1967, finally proving the commercial viability of oil sands mining 40 years after the Bitumount experiment. But the ghost of Bitumount seems to have haunted the Fort Hills lease ever since. It would take almost 100 years before Fort Hills would become a completed reality. The history of the project is a long and tortured one.
Fort Hills - A Timeline of Key Events

1994
- United Tri-Star (UTS) purchase 10% interest

1995
- TrueNorth Energy (subsidiary of Koch Industries) purchased 78% of Fort Hills
- Fort Hills receives regulatory approval. Later that year, UTS Energy delays construction
- Petro-Canada purchases 60% stake in project
- Teck acquires 20% stake (15% from UTS, 5% from Petro-Canada)

2001
- SOLV-Ex and UTS purchase adjacent leases from Petro-Canada, christen the properties Fort Hills
- UTS and TrueNorth file application for Fort Hills mine with Alberta Regulator
- UTS buys out TrueNorth

2004
- Changes from paraffinic to naphthenic froth treatment. Sturgeon County Upgrader added and new mine plan.

2005
- Petro-Canada / Suncor merger. FH Upgrader shelved at $2.5B writedown

2006
- Back to PFT basis with $15.4B mine plus Upgrader. AB Government gives partners a deadline of 2011 to build the facility or lose permits

2007
- Total purchases UTS Energy for $1.5B, giving them 20% stake in the project
- Suncor purchases additional 10% working interest

2009
- Fort Hills given green light to proceed with a $13.5B price tag (construction begins)

2010
- New Orleans

2013
- Kananaskis

2015
- San Francisco

2018
- Denver
- First production of Froth

First oil produced.

Working equity change between partners:
- 53.06% Suncor
- 26.05% Total
- 20.89% Teck

Some images from construction

Surge bin foundation

Froth Settling Unit

Primary Separation Cells

Secondary Extraction undergrounds

Fort Hills recent milestones

First Froth
2017...

First Oil
“ie. hotbit”
2018...
Fort Hills - Arial overview “what you get for $17 B!”

See video “Fort Hills: a moment in time”

posted Jan 29, 2018 (1:14)

Fort Hills is an oil sands mining project located 90 km north of Fort McMurray, Alberta. Suncor, with its joint venture partners Total E&P Canada and Teck Resources, began construction of the 194,000 barrel per day facility in 2013. Watch this time lapse to see how the construction of Fort Hills progressed from 2013-2017.

https://www.youtube.com/user/SuncorEnergy

https://youtu.be/dGn4x4dxLRY
AB Logistics for Market Access Infrastructure

**Asset Operator**

- **Hot Bitumen 4 KM Pipeline from SE to NCP**
  - Operated by Secondary Extraction
- **Northern Courier Pipeline**
  - Operated by TCPL
- **Norlite Pipeline line fill in Operation**
  - Operated by Enbridge
- **Wood Buffalo Extension**
  - Operated by Enbridge
- **Hardisty tanks in service with OS product**
  - Operated by Enbridge
- **East Tank Farm**
  - Operated by SELC

**Options**
- Export Pipeline
- Rail
- Local Market

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**Diagram Elements**

- Fort Hills Mine Terminal
- Northern Courier
- Hot Bitumen Pipeline
- East Tank Farm
- Blending w/Condensate
- Wood Buffalo Extension
- Athabasca Pipeline
- Nova Scotia (NCP)
- Wood Buffalo Pipeline
- Cheecham Terminal
- Waupisoo Pipeline
- Edmonton Terminal
- Norlite Diluent Pipeline
- Hardisty Terminal

**Existing vs. New**

- Existing
- New

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[1] Note: There is a number 1 in the diagram, but the context of its importance is not clear from the given information.
Suncor currently has approximately 750 mbpd of near-term market access\(^1\).

Proposed projects would provide Suncor with expanded pipeline connectivity to markets.
MINED Bitumen Paraffinic Froth Treatment

While our oil sands Base Plant uses a first generation extraction process called Naphthenic Froth Treatment, our new Fort Hills mine will use a process called Paraffinic Froth Treatment (PFT).

The bitumen product we obtain using this partial upgrading process has been upgraded to a better quality as we cut approximately 10% of the bottom of the barrel – which is essentially composed of low value heavy asphaltene molecules and mineral solid particles.

Rejecting the portions of heavy hydrocarbon closer to source is expected to reduce both the diluent required for transportation and the energy and hydrogen needed to upgrade and refine the bitumen.

This higher quality oil sands product can be processed at a wider range of refineries.

IN-SITU

Our SAGD LITE (Less Intensive Technically Enhanced) program aims to lower our steam-to-oil ratio (SOR) through the co-injection of steam and surfactants, solvents or noncondensable gas. A reduction of the steam-to-oil ratio in excess of 15% would enable more efficient oil recovery while using less energy and water – with minimal associated costs or environmental footprint at our existing facilities. In 2015, we successfully executed pilot projects testing surfactant technology and extended one to a larger technology demonstration in 2016.

Another innovative approach to in situ technology is electromagnetically assisted solvent extraction, or EASE. Instead of using steam to heat the bitumen, radiofrequency electromagnetic energy – similar to a home microwave oven – may be used to heat the water already in the reservoir and then the reservoir itself. Adding a solvent further lowers bitumen viscosity, which is expected to enable production at economic rates. We are reviewing a field demonstration at our Dover Site to demonstrate the viability of this process.

In partnership with the Nsolv Corporation, in 2013 we started field-testing a condensing solvent extraction technology known as the NsolvTM process. This uses the horizontal well technology developed for SAGD, but does not use any water. Instead, Nsolv uses vapourized propane or butane to provide heat the way steam does. But because this solvent also dilutes and mobilizes the bitumen, reservoir temperatures do not need to be raised above 60 C, with the potential to require up to 80% less energy. This potential energy reduction could have a significant impact on greenhouse gas emissions.

If commercially successful, these in situ technologies offer potentially significant benefits over conventional SAGD technology, including:
- reducing energy requirements by up to 75%, which would reduce both costs and GHG emissions;
- leaving asphaltenes in the reservoir, producing a lighter oil, with lower GHG footprint when refined into gasoline and other products;
- greatly reducing or eliminating process water needs, including water treatment and handling equipment; and
- significantly reducing the size and complexity of the surface facility, reducing both capital costs and land footprint.
Oil sands deposits located at a depth of less than 75 meters can be surface mined. Surface mining (or open-pit mining) is only viable for a portion of bitumen located in the Athabasca region north of Fort McMurray.

This represents about 20% of the total recoverable reserves.

The remaining 80% of the bitumen is too deep to be mined and can only be extracted from the oil sands in-situ (or in-place) using steam. Most of the in-situ facilities currently in operation extract bitumen from a depth of at least 200 meters.
Naphthenic Froth Treatment:
- requires an intermediary upgrading step to remove water, solids and asphaltenes before refining
- bitumen contains ~98% bitumen and 2% solids and water (nominal 3000-6000 ppm solids)

Paraffinic Froth Treatment:
- bitumen blend can be sold directly to a high-conversion refinery
- bitumen contains ~99.9% bitumen and ~0.1% water (and a few hundred ppm solids ie>low to typical vs classic dilbits)
Differences between Paraffinic Froth Treatment (PFT) vs “classic” Naphthenic Froth treatment

In **conventional froth treatment**, the solvent naphtha is used at relatively low solvent-to-bitumen ratio. Typical diluted bitumen products from this process contain 1-2% percent of water and about 0.5% mineral solids. Because of the level of contamination, the bitumen is **not suitable for pipelining or refining**, thus the bitumen is generally upgraded.

The second technology is **Paraffinic Solvent Froth Treatment** (PSFT), which is a relatively new method of bitumen froth treatment. This treatment was developed in 1990 with significant research contribution from CanmetENERGY. The bitumen product obtained through PFT has **lower levels of contaminants, such as water and mineral solids, reaching almost 2 orders of magnitude**.

The content of **asphaltenes**, which are heavier molecules contributing to the high viscosity in the bitumen, **can also be lowered**, thus upgrading the bitumen quality. Mixing paraffinic solvent at required solvent-to-bitumen ratio (S/B) results in the formation of aggregates composed of emulsified water droplets, mineral solid particles and precipitated asphaltenes shown in the microscopic image. Aggregated contaminants are easy to separate in conventional settlers, **requiring less energy**.
Differences between Paraffinic Froth Treatment (PFT) vs “classic” Naphthenic Froth

The key to Froth Treatment is the type of light hydrocarbon used as the solvent/diluent. There are 3 types of naturally occurring hydrocarbon compounds, classified according to their molecular structure:

**Paraffins**: straight chains or branched chains of carbon atoms, also known as *alkanes*; paraffins are **saturated** hydrocarbons (where each H atom is joined to a C atom) and have the chemical formula $\text{C}_n\text{H}_{2n+2}$.

**Naphthenes**: saturated hydrocarbon compounds arranged in the form of **closed** rings (cyclic) with a chemical formula $\text{C}_n\text{H}_{2n}$; naphthenes are very stable and are sometimes referred to as *cycloparaffins* or *cycloalkanes*.

**Aromatics**: unsaturated hydrocarbons (hydrogen deficient) with ring-type (cyclic) compounds, consisting of at least 1 benzene ring.

Differences between Paraffinic Froth Treatment (PFT) vs “classic” Naphthenic Froth

- **Lower density**
- **Lower viscosity**
- **Lower boiling point**
- Will precipitate asphaltenes

- **Higher density**
- **Higher viscosity**
- **Higher boiling point**
- Will dissolve asphaltenes
The presence of asphaltenes in the bitumen stabilize the water/solids/bitumen emulsions, making it difficult to produce a good quality product unless the asphaltenes are simultaneously precipitated. Since asphaltenes are insoluble in the presence of paraffins, a paraffinic solvent encourages asphaltene precipitation.

As the asphaltenes precipitate and agglomerate, they bind with the water and solids, producing a bitumen product virtually free of water and solids. Another beneficial side-effect of paraffinic solvents is the partial removal of the heavy asphaltene fraction (up to 50%), which now makes the bitumen more marketable.

Although it is possible to precipitate asphaltenes with a napthenic solvent, it would require a much higher fraction of solvent. Precipitation of asphaltenes is much more easily achieved with paraffinic solvents that have a lower carbon-number (such as pentane and hexane).
Fort Hills – A Mining and Extraction Process
The Fort Hills mining operation includes two main pits and a mine fleet capable of sustaining a production of 14,500 tonnes of oil sand per hour. Oil sands are excavated from mine using hydraulic or electric shovels (shown). Oil sands are trucked (350-400 tonnes) to the Ore preparation plant.
Fort Hills – Ore Preparation Plant (OPP)

- Receive ore and break it down into smaller pieces (remove rocks and any oversized materials)
- Transferred via conveyors to a surge bin
- Crushed ore is conveyed to rotary wet screens, converted to slurry by adding hot process water (HPW) and transported to primary extraction
Maximize the recovery of bitumen from oil sands slurry while rejecting as much of the solids as possible.

- Slurry is processed in Separation Cells to separate bitumen from water and sand.
- Sand settles to the bottom of the Separation Cell and bitumen and tiny air bubbles form a froth at the top.
Fort Hills – Tailings

**Tailings**

- The byproducts of the extraction process which contain sand (coarse tails), clays (fine tails, mature fine tails) and trace oils/asphaltenes.
- Tailings are collected and pumped into the Tailings pond to allow for settling of sediments.
Fort Hills – Paraffinic Froth Treatment

**Paraffinic Froth Treatment**

- Bitumen is mixed with a chemical solvent to:
  - remove remaining solids and water
  - reduce viscosity of the bitumen by precipitating asphaltenes
Fort Hills – Hot Bitumen Product (Deasphalted Bitumen)

Deasphalted Bitumen

- The final product of the Froth Treatment Process is a partially de-asphalted dry bitumen with very low content of:
  - Minerals (solids) (~200-600 ppm)
  - Water (~100-500 ppm)
  - Solvent (~100-800 ppm)

- Stored in 125C degree tanks to maintain heat and flowing viscosity

- Product does not meet pipeline specifications of course as it still requires diluent addition
Like other Athabasca dilbits, PFT Bitumen blends are still viscosity limited for pipelines despite decreased asphaltenes.

<table>
<thead>
<tr>
<th>Key Market Crude Comparison</th>
<th>PFT</th>
<th>PFT</th>
<th>SAGD</th>
<th>SAGD</th>
<th>SAGD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density kg/m³ (not constraining)</td>
<td>FRB</td>
<td>KDB</td>
<td>AWB</td>
<td>BHB</td>
<td>CDB</td>
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<tr>
<td>Viscosity cSt (primary blend constraint)</td>
<td>&lt;350</td>
<td>&lt;350</td>
<td>&lt;350</td>
<td>&lt;350</td>
<td>&lt;350</td>
</tr>
<tr>
<td>Sulfur wt%</td>
<td>3.9</td>
<td>3.9</td>
<td>3.9</td>
<td>3.8</td>
<td>3.9</td>
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<tr>
<td>Ni ppmw</td>
<td>52</td>
<td>49</td>
<td>70</td>
<td>62</td>
<td>70</td>
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<tr>
<td>V ppmw</td>
<td>125</td>
<td>132</td>
<td>187</td>
<td>166</td>
<td>186</td>
</tr>
<tr>
<td>TAN mg KOH/g</td>
<td>2.2</td>
<td>2.0</td>
<td>1.8</td>
<td>2.4</td>
<td>1.7</td>
</tr>
<tr>
<td>Naptha Yield wt% (IBP-177C)</td>
<td>15</td>
<td>16</td>
<td>19</td>
<td>20</td>
<td>19</td>
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<tr>
<td>Distillate Yield wt% (177-343C)</td>
<td>11</td>
<td>12</td>
<td>13</td>
<td>14</td>
<td>14</td>
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<tr>
<td>Gasoil Yield wt% (343-543C)</td>
<td>31</td>
<td>32</td>
<td>27</td>
<td>29</td>
<td>28</td>
</tr>
<tr>
<td>Resid Yield wt% (543°C+)</td>
<td>42</td>
<td>40</td>
<td>41</td>
<td>38</td>
<td>40</td>
</tr>
<tr>
<td>MCR wt%</td>
<td>9.0</td>
<td>8.9</td>
<td>10.7</td>
<td>9.6</td>
<td>10.6</td>
</tr>
<tr>
<td>C₅ Asphaltenes</td>
<td>7.5</td>
<td>(7)</td>
<td>base</td>
<td>base</td>
<td>base</td>
</tr>
<tr>
<td>Coke Yield from Resid</td>
<td>lower</td>
<td>lower</td>
<td>base</td>
<td>base</td>
<td>base</td>
</tr>
</tbody>
</table>

Coker Feed Qualities

| Viscosity of Resid | lower | lower | base | base | base |
| Coke Yield from Resid | lower | lower | base | base | base |
| Resid Fraction C₅ Asphaltenes wt% | 18.5 | ~19 | 26.3 | 25+ | 25+ |
| Resid Fraction C₇ Asphaltenes wt% | 7.5 | 7.6 | 14.9 | 14+ | 14+ |
| S in Resid wt% | 6.1 | 6.4 | 6.5 | 6.6 | 7.0 |
| Nickel in Resid ppmw | 113 | 121 | 147 | 140 | 141 |
| Vanadium in Resid ppmw | 279 | 320 | 381 | 395 | 381 |

Process results in improver coker liquid yields
lower C₅ C₇ insoluble asphaltenes due to PFT
lower coker feed sulfur

lower metals
What’s in the Name FRB?
Let’s Consider Decarbonization / Life Cycle Assessment

**FRB = Fort Hills Reduced Carbon Life Cycle Dilbit Blend**

Decarbonization is enhanced through the GHG efficient rejection of the most “difficult to process” hydrocarbon fraction(s) in Bitumen/Crude Oil as far upstream as possible.

Reduction of contaminants in the bitumen product (metals, sulfur, nitrogen) allow modest energy improvement in Refinery processes

- can reduce coke produced per barrel of the decarbonized residue (VTB)
- may realize energy improvements due to optimized/altered refinery product yields
- alternatively, this reduced processing energy intensity could be represented as simply lower Refinery crude runs to meet the same product yield and volumes

*With this context, Fort Hills PFT Bitumen is a decarbonized product ... let’s dig further into details.*
Decarbonization through Deasphalting reduces metals content in produced PFT Bitumen

(3rd part source)

Contaminants such as metals are concentrated in the heavy residue fractions. Asphaltene rejection leads to a disproportionate level of metals rejection.

Data suggests 20 – 40% reduction in Ni and V at 10% asphaltene rejection (90% yield)

Note however that Carbon and Hydrogen (and thus C:H ratio) remains essentially constant across the entire range of bitumen boiling points (starts in distillate range)

Source: Supercritical fluid extraction reveals resid properties, Syncrude R&D, Chung et al., O&G Journal, Jan20, 1997
Decarbonization through Deasphalting reduces coke pre-cursors* from bitumen (3rd party source)

The asphaltene fraction contains proportionately more multi aromatic ring hydrocarbons. These high molecular multi aromatic rings are coke precursors; lower coke make when reduced

Source: Supercritical fluid extraction reveals resid properties
Syncrude R&D, Chung et al., O&G Journal, Jan20, 1997
Asphaltene structure = Strauss, et al.

* - illustrative hydrocarbon structures
Data supported findings...

FRB blended bitumen is a partially decarbonized bitumen product. Consider however that it does not have a “materially different carbon” content vs a SAGD blended bitumen.

“Carbon content alone is an inappropriate measure when comparing crude oil LCA”

• Despite common perception, decarbonization through deasphalting does not materially reduce the carbon content of bitumen blend:
  – The PFT process indeed reduces the asphaltene content of bitumen, but the carbon (and hydrogen) content of the remaining deasphalted blend is only marginally altered.
  • FRB uses less (lower carbon/higher Hydrogen content) diluent than SAGD bitumen.
  – Data illustrates that after distillate/gasoil boiling range, the carbon/hydrogen content of increasing boiling point hydrocarbons remains steady (is near asymptotic) into the resid range.

• Refinery Carbon intensity by straight run crude yield/quality is but one small aspect of total Wells to Wheel Carbon Life Cycle Analysis.
  – Nominal refineries contribute 7-12% of total LCA carbon intensity from lightest sweet to heaviest blend crudes, and thus small crude carbon content changes of 1-2% in crudes become immaterial (LCA impact of <0.2%).

• Refinery conversion configuration (carbon removal / hydrogen addition), and G/D ratio intensity play MORE major roles in Refinery LCA impacts that resid quality alone.
  – Coker Yield benefits from FRB’s lower resid asphaltene levels do contribute to value optimization but less so on carbon intensity measures (all coker feed is eventually consumed to CO2 through fuel, including combustion of all produced coke).
Further Deasphalting Advantages for Suncor (and Alberta)

- We have a unique opportunity to capture (and sequester) asphaltenes at our facilities
  - These would otherwise get combusted as fuel coke by others

- Few, if any, other jurisdiction in North America has this advantage to sequester the bottom of the barrel

- Reduced diluent needs lowers the footprint logistics of diluent and end commodity transportation
Comments regarding PFT process and Asphaltene rejection

The PFT process alters Bitumen from a nominal 17wt% C5 Asphaltene content and removes approximately 7wt% of those Asphaltenes, leaving a much reduced density/viscosity bitumen (with approx. 10% C5 Asphaltenes)

- **Asphaltenes** are fully soluble in the base bitumen. They are a solubility class of molecules. They are layered, complex structures that exists within similar MW molecules that are more soluble (maltenes). Asphaltenes have a distribution of quality and are not a single molecule.
- These asphaltenes boil well into the Residue distillation range and their characteristics are highly varied and complex making characterization by specific species impossible, thus bulk fraction analysis is what is done (ie total amounts of saturates or resins or aromatics or asphaltenes or maltenes etc)

The PFT process concentrates/increases the base bitumen yield of distillates (~10%) and gasoils (~30%), leaving their quality unchanged since deasphalting is a physical process of asphaltene rejection, not a chemical conversion.

The reduced Asphaltenes lower the bulk PFT bitumen viscosity, allowing approximately 5-8 % less diluent to meet pipeline viscosity limits.

- **SAGD** bitumen can be deemed to be nominal 70% Bitumen / 30% diluent
- **PFT** bitumen can be deemed to be nominal 77% Bitumen / 23% diluent

Diluent itself has a lower carbon/hydrogen ratio than bitumen (5.3 vs 8.5) as it is mostly LPG to light naphtha thus PFT blends like Fort Hills FRB have less needed “dilution” of the bitumen with this higher hydrogen containing diluent.
residual Asphaltene and Maltene boiling ranges for PFT bitumen

<table>
<thead>
<tr>
<th></th>
<th>Maltene</th>
<th>Asphaltene</th>
<th>PFT Bit</th>
<th>Full Bit</th>
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</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>84.1</td>
<td>81.1</td>
<td>83.8</td>
<td>83.6</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>10.6</td>
<td>7.8</td>
<td>10.3</td>
<td>10.5</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>0.3</td>
<td>1.0</td>
<td>0.4</td>
<td>0.4</td>
</tr>
<tr>
<td>Sulfur + Oxygen by diff</td>
<td>5.0</td>
<td>10.1</td>
<td>5.5</td>
<td>5.5</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>Iron</td>
<td>6</td>
<td>131</td>
<td>19</td>
<td>91</td>
</tr>
<tr>
<td>Nickel</td>
<td>31</td>
<td>258</td>
<td>54</td>
<td>107</td>
</tr>
<tr>
<td>Vanadium</td>
<td>78</td>
<td>715</td>
<td>142</td>
<td>276</td>
</tr>
</tbody>
</table>

Percentage of carbon and hydrogen in Maltene and Asphaltene, alongside typical values for PFT bitumen and full bitumen. The graph shows the boiling ranges in Celsius for different percentage of bitumen by HTSD, with Maltene and Asphaltene as key components.
PFT Bitumen improves the quality of the residual crude fraction
Carbon Hydrogen Crude Review

Consider the Carbon content measures of crude oils …

This parameter is a function of the molecular species true, but one key note is that as the liquid boiling points get higher into distillate and heavier range, the mass of Carbon to Hydrogen being added approaches an asymptotic measure due to simply adding one carbon (MW=12) molecule and nominally two hydrogen (MW=2) or equivalent bond molecules to that structure.

Ring structures, double bonds, contaminants like Sulfur and Nitrogen do play a role, but both lab measures and fundamentals imply the marginal relative results shown in the subsequent graphs.

Crude Oil Carbon numbers range from
C1- C10 for Naphthas (BP up to 350 degF) (very little C1-C3)
C10- C20 for Distillates (BP 350 to 650 deg F)
C20- C42 for Gasoils (BP 650 to 1000 deg F)
C42- C100+ for Resids (BP 1000 to ~1800 degF) One cannot measure boiling points over 1382 deg F

Many believe Crude oil density and nomenclature such as light/heavy imply dramatically different carbon hydrogen content. While refinery named fraction yields can vary greatly between LPG and light oils and onwards to vacuum bottoms/resid yield, the Carbon wt% content itself does not vary as greatly after gasoils. The variability of total carbon content amongst crudes is much smaller than many appreciate.

While methane and coke from upgrading processes are indeed quite different, “liquids” within crude oil fractions can be shown to be less different.
Carbon Hydrogen Content Examples by Fuel type and Crude Oils (3rd part source)

Carbon content is 82-85wt% for a wide range of oils.
Carbon Hydrogen Ratio by Fuel type and Crude Oils

>>> Similar range >>>
Illustration of Carbon Hydrogen Ratio model for light “Fort Sask like” Diluent …notice “levelling off” of ratio at higher Carbon numbers

Carbon Content of CFT Diluent is 84wt% Carbon, 15.99wt% Hydrogen, Sulfur 0.023 wt%, trace N and O) …this super light diluent has a C/H mass ratio of 5.25
Illustration of Carbon Hydrogen mass Ratio model for light “Fort Sask like” Diluent …notice “levelling off” of ratio at higher Carbon numbers
Fort Hills annual average assay blend

![Graph showing carbon hydrogen weight ratio per Maxxam/Hcams assay against FDB yield wt% for various fractions: Naphtha, Distillate, Gasoil, Resid. A table includes FDB wt%, whole crude, avg C.H ratio, resid fraction, avg C.H ratio, with values for Carbon, Hydrogen, Sulfur, Nitrogen, Oxygen (by diff).]
Early Fort Hills Life Cycle Assessment View …

**FRB = Fort Hills Reduced Carbon Life Cycle Dilbit Blend**

Fort Hills has measurable GHG Life Cycle improvements over SAGD dilbits …

1. First from mining/extraction of hotbit, lowering GHG footprint vs SAGD (Firebag)
2. Second from improved Bitumen quality, and with less diluent
   *In addition, precipitated Fort Hills Asphaltenes are NOT used as Fuel (Sequestered “Carbon”)*
   …few jurisdictions outside Alberta has that advantage!
3. Finally, FRB results in improved/lower coke yields at refineries, and/or less crude for same products

![Well to Tank Intensity Graph](image)

leftrightarrow Avg US Crude @ ~96
Future … more reduction in Athabasca Bitumen Blend Asphaltenes coming?

Why?

- Lower carbon crudes desired
  - Effective carbon sequestration

- More effective use of limited pipeline access
  - Reduction in diluent

- Less contentious and logistically constraining vs other partial upgrading solutions … but those can be solved with Engineering and Technology as well!

41% C5A
- • Classic Athabasca Bitumen
  • SAGD + mined

10% C5A
- • Paraffinic Froth Treatment
  • Kearl/Albian/Fort Hills
  • Mineable reserve without an upgrader

5% C5A
- • "Nsolv" process ??

Zero C5A?
- • ????
End