COMMERCIALIZING A RESIN-COATED PROPPANT

by

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Submitted in partial fulfillment of the requirements for
the degree of Master of Science

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*We also certify that written approval has been obtained for any proprietary material contained therein.
Dedicated to my parents and family.
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HD Proppants, an early stage venture requesting strategic direction, has set out to commercialize a novel coating chemistry for resin-coated sand, a proppant that operators use to extract oil and natural gas from hydraulically-fractured shale. This study discusses technologies that have made shale fracturing economically feasible, introduces the proppant’s role in hydraulic fracturing, and presents fundamental physics equations that govern proppant performance. A financial framework and competitive landscape help describe the commercial viability, technical feasibility, and marketplace value of HD Proppants in comparison to competitors’ products and strategies. Absent major developments that change the context, this study finds that HD Proppants should abandon independent business development. Alternatively, HD Proppants should aggressively pursue a licensing arrangement to initiate joint venture product development with a competitive resin-coated sand company that would most value the incremental innovation possible from using HD Proppants’ novel coating chemistry.
Conclusions and Recommendations

Section 1 covers the use of proppants in the energy and mining industry – it identifies the contribution of proppants to the cost of an average horizontal and vertical well, teaches the technical factors that differentiate different types of proppants, and presents a literature review that argues that higher quality proppants drive higher well productivity. Section 1 suggests three macro-economic factors to justify the 10-fold growth in proppant demand that occurred between 2000 and 2012; a demand trajectory that analysts predict will maintain double digit annual growth for the next five years. The rapid growth in proppant consumption, built on a foundation of fundamental trends (increased energy consumption and demand for clean energy), describes a favorable market for HD Proppants. Furthermore, the literature review advocates strongly for the market segment of high conductivity proppants (a segment to which HD Proppants will belong), further strengthening the favorable prognosis for HD Proppants when analyzed from a market need perspective.

Section 2 maps out the upstream oil and gas industry and identifies the operator as the player that makes the proppant buying decision. A review of a behavioral economics study of operators in North Dakota describes operators as incredibly risk averse – when given the choice. The study shows, operators prefer to lower the variance of well production output by using lower risk completion techniques, e.g., by deploying previously vetted proppants. Well operators avoid experimenting with new techniques that could raise profitability (lowering costs or increasing output), instead opting to optimize exiting fracturing procedures. The study of operator decision making bodes an unfavorable prognosis for HD Proppants because, as a new entrant, its proppants
inherent risk, which operators seek to avoid. Additionally, the behavioral economics study reveals a data bias by which operators overweight the value of cause and effect data points garnered from their own wells compared to competitor generated data. Section 2 concludes that not only will HD Proppants experience difficulty convincing operators to buy its proppant, but convincing one operator to buy will do little to help convince another. The sales cycle will shorten significantly only when HD Proppants can show efficacy within a portfolio of wells owned by a single operator, a process that the study of well production shows can take years. Strategic insights from Section 2 suggest HD Proppants, or its licensor, should focus on selling to operators that have shown patterns of experimenting with proppant selection (Section 2 recommends a database HD Proppants can use to identify these operators), and encourages HD Proppants to raise enough capital to fund a burn rate that can cover the time necessary to gain sales traction with multiple operators.

Section 3 analyzes HD Proppants’ proposed approach to manufacturing its resin-coated proppant. It identifies the venture as still having high technical risk, as HD Proppants has yet to successfully coat sand with its proprietary resin, even in a lab setting. Showing evidence of technical feasibility is a critical milestone that HD Proppants must prioritize to increase the possibility of commercial success. Section 3 also presents a financial framework to analyze the proposed business model of building a manufacturing plant. A minimum full scale production line of 20 tons per hour will require a $5 million investment to produce 27,000 tons of proppants annually, which HD Proppants needs to sell at approximately $210 per ton to meet required return-on-investment metrics. The financial analysis concludes the venture will be highly capital intensive (a poor
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prognosis). When studied in context of technical risk and operator risk-adverse behavior, the financial analysis determines the venture cannot proceed without strategic partners to fund two identified critical cost elements: capital equipment and sand procurement.

Section 4 discusses the benefits of using the HD Proppants coating and the resultant proppant, compared to its costs. Without performance test data to make an argument for increased well production, Section 4 generally speaks to the merits of using resin-coated proppants over uncoated sand or ceramics proppants. Section 4 also presents a framework to estimate the cost advantage of HD Proppants’ novel resin chemistry compared to two identified competitive resin chemistries. A resin-coated proppant produced by HD Proppants is predicted to have about a $20 per ton cost advantage versus the industry norm, which is about 6-10% of the average resin-coated proppant cost.

Finally, Section 5, a study of the competitive landscape, begins by rewriting proppant characteristics, discussed in Section 1 under technical pretenses, using outcome expectation terminology, a specific grammatical construct developed by business analysts to view not only direct competition (resin-coated sand) but also alternative choices and non-consumption. Section 5 briefly covers six proppant companies that fulfill the outcome expectations discussed and that already employ many of the strategic partnerships recommended for HD Proppants (again, an unfavorable prognosis for HD Proppants). Section 5 has a detailed examination of Oxane Materials, a new entrant that has succeeded with a contradictory value proposition to HD Proppants – making a top line product that garners a 100% price premium over the most expensive ceramic proppants. Studying Oxane Material’s success factors reinforces the need for strategic
industry partners to add in financing development beyond capital, such as development expertise, capital equipment, sand supply, or agreements to purchase product.

Overall, the analysis concludes with an unfavorable commercial feasibility for HD Proppants. While the proppant industry has undergone rapid growth, and analysts expect the industry to continue growing, the industry’s risk averse behavior, as described in Section 2, and capital intensity, as described in Section 3, does not favor new entrants. Furthermore, the analysis does not find HD Proppants’ cost advantage ($207 per ton competing with resin-coated proppants sold from $200 to $490 per ton) to be disruptive, that is, it would not dramatically alter marketplace dynamics. Finally, while the analysis identifies strategic options to increase HD Proppants’ competitive advantage, competitors have already implemented many of the strategies. Without any major developments that change the conclusions of the following study, HD Proppants should abandon independent business development. Alternatively, HD Proppants should aggressively pursue a licensing arrangement to initiate joint venture product development with a competitive resin-coated sand company that would most value the incremental innovation possible from using HD Proppants’ novel coating chemistry.
1 Extracting Oil and Natural Gas from Sale Formations

The energy mining industry uses proppants, sand-like particulates, in extracting natural gas and oil from resource-rich, but difficult to mine reservoirs. As shown in Figure 1, between 2000 and 2012, proppant demand grew ten-fold.¹ Market analysts estimate North America consumed 60 billion lbs. of proppants (30 thousand tons) in 2012, amounting to a $3.7 billion industry.² Predicted to maintain double digit annual growth, experts estimate yearly proppant demand will surpass 100 billion lbs., or $9.4 billion, by 2017.³

Figure 1: Growth in proppant demand by segment (The Freedonia Group, Inc., 2013)
1.1 Proppant Demand

Three macro-economic factors account for the dramatic increase in proppant demand, 14 billion lbs. (7 million tons) in 2007 to 100 billion lbs. (50 million tons) projected in 2017. As a reference, long horizontally drilled hydraulically fractured wells require 3 to 5 million lbs. of proppants (1500 to 2500 tons).\(^4\)

1.1.1 Rapid worldwide growth in demand for natural gas

Worldwide demand for natural gas has quadrupled over the last half-century, from 23 trillion cubic feet in 1965 to 104 trillion cubic feet in 2009.\(^5\) When converted to natural gas, an average home requires approximately 90 thousand cubic feet of natural gas per year, for space-heating, water-heating, cooking, etc.\(^6\) However, in 2009 the residential sector consumed only 20% of natural gas in the United States; 30% went towards generating electricity, 25% for industrial purposes, 15% for commercial, and 10% for other uses.\(^7\) In part, natural gas consumption has increased with global population growth; however, consumers view natural gas as a clean source of energy as analysts estimate it emits 44% less CO\(_2\) than coal when burned.\(^8\) Trends in clean energy have driven proportionately higher natural gas consumption than the general growth in energy demand. Among various sources of energy including petroleum, coal, renewables, etc., natural gas has grown from 15.6% of total consumption in 1965 to 24% in 2011.\(^9\)

1.1.2 Increase in withdrawal of natural gas from unconventional rock formations that require stimulation wells (vertical or horizontal)

The US Energy Information Administration categorizes natural gas withdrawals from four sources: gas wells, oil wells, shale gas wells, and coalbed methane.\(^10\) Geologists further classify withdrawal from gas wells and oil wells as “conventional” reservoirs
since the organic-rich gasses have migrated to rock formations of very high matrix permeability\(^1\). In contrast, geologists categorize coalbed methane withdrawal and shale gas fracturing as “unconventional” because, while the resultant gas still measures with high total organic content, ultra-low permeable rock formations contain the gasses.\(^{11}\) Historically, mining companies have favored conventional reserves over unconventional reserves because highly permeable rock allows for easier extraction; however, technological advances in horizontal drilling and hydraulic fracturing have allowed economic withdrawal of natural gas and oil from heretofore impervious geological formations.\(^{12}\)

1.1.3 Increased use of fracturing in horizontal wells, as opposed to vertical ones

Horizontal wells increase drilled length, and, consequently, use more proppants. For example, a vertical natural gas well in the Barnett Shale reserve in the early 2000s would require about 300,000 lbs. of proppant. Present day horizontal fracturing into shale in the same region requires 20 or more stages (evenly spaced perforations along the length of the horizontal; horizontal wells have more stages than vertical wells, requiring more proppants) and consumes 3 to 5 million lbs. of proppant.\(^{13}\)

---

\(^1\) “Matrix permeability” describes the ease at which oil or natural gas can flow through the 3-dimensional fissures in the reservoir formation, used interchangeably as “permittivity”, or just “permeability”. Darcy’s Law, described in 1.3.1, quantitatively describes formations of low permeability (difficult for mining) or high permeability (easy to mine). Operators use hydraulic fracturing to unlock resources from the abundant low permeability reservoirs, which were not otherwise economically feasible to mine.
Figure 2 shows that drillers started ~150 horizontal wells in 1991 and, by 2013, the rate of new wells increased to ~1,350 per year (an increase of ~9 times). Horizontal wells grew from a quarter of all wells drilled in 1991 (~1,000 wells drilled), to three quarters in 2013 (~1,800 wells drilled). The rapid increase in horizontally fractured wells ultimately dictated the ten-fold growth in proppant demand increase between 2000 and 2012.

1.2 Economic Withdrawal of Resources from Shale Rock
In Figure 3, author Michael Vincent quantifies the effect of horizontal well drilling and fracturing technology advances in terms of increased effective contact area between the well and rock formation. Vincent describes that drilling horizontally within resource-rich layers, as opposed to vertically across layers, increases throughput because, as research suggests, “fractures typically provide extremely low permeability in the vertical
direction.”

Vincent states that even unconventional reservoirs have a ratio of vertical to horizontal permeability of “often below 0.01 and frequently below 0.001.”

Vincent suggests shale, comprised of horizontal layers, has lower permittivity within the plane of the sheets than across multiple planes.

Hence horizontal drilling, in the plane of the sheets, helps unlock resources from shale reservoirs. Multiple transverse fractures, for example 15 fractures in a typical Marcellus horizontal shale fracture, allow for five orders of magnitude (10,000 times) more contact area to the natural gas when using a horizontal fracture (Biwing Fracture in Fig. 3) compared to an uncemented vertical well. As Vincent argues, the technological progression has allowed for economic withdrawal of oil and gas from otherwise highly impermeable geological formations, such as shale.

Figure 3: Technological progression in drilling techniques has unlocked economically justified withdrawal of resources from low permeable rock formations (Vincent, 2011) Image © Vincent, 2011
1.3 Natural Gas from Unconventional Reservoirs

Due to the technological advances Vincent describes (in Figure 3), Figure 4 shows that over the last 15 years America has seen accelerated growth in natural gas withdrawal from shale rock, an unconventional reservoir, through a process called hydraulic fracturing (“fracking”). In absolute terms, domestic shale fracking for natural gas has grown approximately five-fold, from 2 trillion cubic feet in 2007 to 10 trillion cubic feet in 2012. The US Energy Information Administration predicts absolute growth will continue to 13.6 trillion cubic feet of natural gas in 2035.21 In relative terms, shale fracturing as a mechanism for natural gas withdrawal grew from 8% of US natural gas withdrawals in 2007, to 35% in 2012.22 The US Energy Information Administration predicts growth in natural gas withdrawal from shale as a percent of total natural gas withdrawals will continue to 49% by 2035.23
Figure 4: Absolute growth of withdrawal from shale gas relative to alternate sources of natural gas (US Energy Administration, 2013)

1.3.1 Permeability of Rock

To quantify the difference between conventional and unconventional natural gas reservoirs, petrophysicists, scientists who study rock formations, define the permeability of rock as a measure of the ease with which liquid permeates a rock formation. French engineer Henry Darcy pioneered the field of petrophysics in 1856 when he experimented with fluid movement through a packed bed of soils and rock. Based on his findings, Darcy’s namesake is now the unit for the permeability of rock. The equation on the left in Table 1 simplifies the Navier-Stokes equations under the assumptions of laminar flow.
and a test sample with a known geometry. The column on the right captures Henry Darcy’s experimental conclusions.

Table 1: Darcy’s permeability experiments as derived from the Navier-Stokes Equation (Glover, 2000)

<table>
<thead>
<tr>
<th>Equation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$Q = \frac{\pi r^4 (P_i - P_o)}{8\mu L}$</td>
<td>Flow rate [cm$^3$/s]</td>
</tr>
<tr>
<td>$r = \text{radius of the tube [cm]}$</td>
<td></td>
</tr>
<tr>
<td>$P_i = \text{inlet fluid pressure [Pa]}$</td>
<td></td>
</tr>
<tr>
<td>$P_o = \text{outlet fluid pressure [Pa]}$</td>
<td></td>
</tr>
<tr>
<td>$\mu = \text{fluid dynamic viscosity [Pa-s]}$</td>
<td></td>
</tr>
<tr>
<td>$L = \text{length of tube [cm]}$</td>
<td></td>
</tr>
<tr>
<td>$Q = \frac{k A (P_i - P_o)}{\mu L}$</td>
<td>Flow rate [cm$^3$/s]</td>
</tr>
<tr>
<td>$A = \text{area of the sample [cm$^2$]}$</td>
<td></td>
</tr>
<tr>
<td>$P_i = \text{inlet fluid pressure [Pa]}$</td>
<td></td>
</tr>
<tr>
<td>$P_o = \text{outlet fluid pressure [Pa]}$</td>
<td></td>
</tr>
<tr>
<td>$\mu = \text{fluid dynamic viscosity [Pa-s]}$</td>
<td></td>
</tr>
<tr>
<td>$L = \text{length of tube [cm]}$</td>
<td></td>
</tr>
</tbody>
</table>

$26^k(\text{Conventional Natural Gas Reservoirs}) \sim 10^{-2} \text{ Darcy}$

$27^k(\text{Unconventional Natural Gas Reservoirs}) \sim 10^{-9} \text{ Darcy}$

$28^k(\text{Cured Cement}) \sim 10^{-13} \text{ Darcy [for conceptual baseline]}$

Using Darcy’s flow rate experiment, petrophysicists quantify conventional reservoirs with a permeability of ~$10^{-2}$ Darcy and unconventional reservoirs with a permeability of ~$10^{-9}$ Darcy, seven orders of magnitude less permeable. Historically, mining companies have favored conventional reserves over unconventional reserves because highly permeable rock allows for easier resource extraction; however, technological advances in horizontal drilling and hydraulic fracturing have allowed economic withdrawal of natural gas and oil from impervious geological formations. 29
1.3.2 US Shale Formations

Figure 5, a map of the major US shale plays,$^{30}$ shows fracking occurs in five general locations across the United States—the Northeast, the Southeast, the Mid-Continental states, Texas, and the Rockies.$^{31}$ Table 2 breaks down the shale formations by recoverable resources, base-lining each US shale region against total US and worldwide untapped oil and natural gas.

Emphasizing the importance of unconventional drilling (enabled by horizontal drilling and fracturing), Table 2 shows that slightly over 50% of the US remaining natural gas reserves lie in unconventional reservoirs (shale), and slightly less than 25% of US remaining oil lies in shale. At market oil and natural gas prices, the US shale reserves are worth $4.06 trillion (natural gas) and $4.29 trillion (oil); the US shale reserves contain enough natural gas to supply US 45 years and oil to supply US 7 years.

A combination of the Marcellus and Utica shale formation, along the Appalachian Mountain region in Ohio, Pennsylvania, and West Virginia, comprises just less than half of the entire US remaining shale natural gas reserves. Similarly, the Eagle Ford and Permian shale formation in Texas contains about half of the US remaining shale oil reserves.$^{32}$ While most of the literature review cited in this paper focuses on domestic hydraulic fracturing as a technology to unlock resources in shale, Table 2 shows that only 15% of the world’s shale natural gas resources, and only 14% of the world’s shale oil resources, lie in the United States. Technologies pioneered in the United States and exported will certainly make a worldwide impact.
Figure 5: Map of US shale plays (FracTracker, 2014)  Image © FracTracker, 2011
## Table 2: US shale formations

<table>
<thead>
<tr>
<th>US Region &amp; Shale Formation</th>
<th>US Remaining Shale Resources</th>
<th>Remaining Reserves and Undeveloped Resources&lt;sup&gt;(a)&lt;/sup&gt; (Tcf)</th>
<th>Remaining Reserves and Undeveloped Resources&lt;sup&gt;(a)&lt;/sup&gt; (Billion Barrels)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>1. Northeast</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Marcellus</td>
<td>369</td>
<td>32%</td>
<td>.8</td>
</tr>
<tr>
<td>Utica</td>
<td>111</td>
<td>10%</td>
<td>2.5</td>
</tr>
<tr>
<td>Other</td>
<td>29</td>
<td>3%</td>
<td>-</td>
</tr>
<tr>
<td><strong>2. Southeast</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Haynesville</td>
<td>161</td>
<td>14%</td>
<td>-</td>
</tr>
<tr>
<td>Bossier</td>
<td>57</td>
<td>5%</td>
<td>-</td>
</tr>
<tr>
<td>Fayetteville</td>
<td>48</td>
<td>2%</td>
<td>-</td>
</tr>
<tr>
<td><strong>3. Mid-Continent</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Woodford</td>
<td>77</td>
<td>7%</td>
<td>1.9</td>
</tr>
<tr>
<td>Antrim</td>
<td>5</td>
<td>1%</td>
<td>-</td>
</tr>
<tr>
<td>New Albany</td>
<td>2</td>
<td>0%</td>
<td>-</td>
</tr>
<tr>
<td><strong>4. Texas</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Eagle Ford</td>
<td>119</td>
<td>10%</td>
<td>13.6</td>
</tr>
<tr>
<td>Barnett</td>
<td>72</td>
<td>6%</td>
<td>0.74</td>
</tr>
<tr>
<td>Permian</td>
<td>34</td>
<td>3%</td>
<td>9.7</td>
</tr>
<tr>
<td><strong>5. Rockies/Great Plains</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Niobrara</td>
<td>57</td>
<td>5%</td>
<td>4.1</td>
</tr>
<tr>
<td>Lewis</td>
<td>1</td>
<td>0%</td>
<td>-</td>
</tr>
<tr>
<td>Bakken/Three Forks</td>
<td>19</td>
<td>2%</td>
<td>14.7</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1161</td>
<td>Trillion Cubic Feet</td>
<td>47.7 Billion Barrels</td>
</tr>
<tr>
<td><strong>Total (USD)</strong></td>
<td>$4.06 trillion&lt;sup&gt;(b)&lt;/sup&gt;</td>
<td></td>
<td>$4.29 trillion&lt;sup&gt;(c)&lt;/sup&gt;</td>
</tr>
<tr>
<td><strong>Total (Years)</strong></td>
<td>45 years&lt;sup&gt;(d)&lt;/sup&gt;</td>
<td></td>
<td>7 years&lt;sup&gt;(e)&lt;/sup&gt;</td>
</tr>
<tr>
<td><strong>Shale as % of US Reserves</strong></td>
<td>53%&lt;sup&gt;(f)&lt;/sup&gt;</td>
<td></td>
<td>22%&lt;sup&gt;(g)&lt;/sup&gt;</td>
</tr>
<tr>
<td><strong>US Shale as % of World Shale Reserves</strong></td>
<td>15%&lt;sup&gt;(h)&lt;/sup&gt;</td>
<td></td>
<td>14%&lt;sup&gt;(i)&lt;/sup&gt;</td>
</tr>
</tbody>
</table>

<sup>a</sup>: “Technically Recoverable Shale Reserves” denotes reserves that are highly likely for mining companies to recover given existing technical abilities.<sup>33</sup>

<sup>b</sup>: Jan-2014 rate of $3.50/thousand cubic ft. of natural gas.<sup>34</sup>

<sup>c</sup>: Jan-2014 rate of $90/barrel of crude oil.<sup>35</sup>

<sup>d</sup>: 2013 consumption of 25,533 billion cubic feet per year.<sup>36</sup>

<sup>e</sup>: 2013 consumption of 18,490 thousand barrels per day.<sup>37</sup>

<sup>f</sup>: 2011 total 2,203 trillion cubic ft. of natural gas reserves in the United States.<sup>38</sup>

<sup>g</sup>: 2011 total 220 billion barrels of oil in the United States.<sup>39</sup>

<sup>h</sup>: 2011 total 7,795 trillion cubic ft. of shale natural gas reserves in the world.<sup>40</sup>

<sup>i</sup>: 2011 total 335 billion barrels of shale oil in the world.<sup>41</sup>
1.3.3 Fractured Well Economics

To overcome formation impermeability, which results in a few natural pathways for oil and natural gas to escape from pockets within shale, operators employ hydraulic fracturing, or “fracking.” In a fracking operation, the mining company will pressurize shale with three ingredients, water (98% by volume), proppants (sand-like particulates), and surfactant (chemical bonders). Operators will then pump out the water, leaving the proppants to maintain (or “prop-up”) the newly created pathways for natural gas or oil.

Table 3 outlines the costs and timeline of the six steps in completing hydraulically fractured shale wells, each typically costing ~$8 million. Before the hydraulic fracturing stage, the mining company secures the land, builds the site, and drills the directional well. After fracturing, the well undergoes completion and then production, shown in Table 3 to last 7 to 15 years in the Marcellus region.

Table 3: Cost structure of an average horizontal well in the Marcellus shale (Hefley et. al., 2011)

<table>
<thead>
<tr>
<th>Cost of Hydraulic Fracturing in a Marcellus Shale Well</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase</td>
</tr>
<tr>
<td>-------</td>
</tr>
<tr>
<td>1</td>
</tr>
<tr>
<td>2</td>
</tr>
<tr>
<td>3</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>4</td>
</tr>
<tr>
<td>5</td>
</tr>
<tr>
<td>6</td>
</tr>
<tr>
<td>Cost Per Well</td>
</tr>
</tbody>
</table>
The high standard deviation of returns ($13 million) in Table 4 shows the highly speculative nature of the oil and gas industry. Having low predictability of well returns suggests well operators could increase aggregate portfolio value not only by increasing the average well production (for example, by employing sophisticated geological analysis, or by using advanced fracking materials) but also by decreasing the variance in well productivity. Operators could show hesitancy in experimenting with new completion procedures, a behavioral economics topic discussed in depth in section 2.2.

1.4 Proppants in Hydraulic Fracturing

Completion companies use proppants during the hydraulic fracturing stage, which just shown in Table 3 costs about a third of overall well completion costs. Proppants are injected into the reservoir to keep shale open and allow for the release of natural gas or oil. Analysts segment proppants into four categories: raw sand, resin-coated sand, ceramics, and other (a catch all to include niche proppants such as crushed walnut shells).

Drilling companies use raw sand by a large margin constituting 80% of the proppant market. David Gallagher, Vice President at CARBO Ceramics, outlines the three different tiers of proppants as shown in Table 5.
Table 5: Three different types of proppants (Gallagher, 2011) (Driscoll, 2013) Image © Gallagher, 2011

<table>
<thead>
<tr>
<th>Tier</th>
<th>Conductivity: Type</th>
<th>Example Companies</th>
<th>General Price Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>High: Ceramics</td>
<td>-CARBO - Oxane Materials - St. Gobain</td>
<td>$.27-.90/lb $540-$1800/ton ~5-10x</td>
</tr>
<tr>
<td>2</td>
<td>Medium: Resin-Coated Sand</td>
<td>-Santrol - Atlas Resins - Momentive</td>
<td>$.10-.245/lb $200-$490/ton ~2-5x</td>
</tr>
<tr>
<td>3</td>
<td>Low: Sand</td>
<td>-Silica Sand - Badger Sand</td>
<td>$0.019--.058/lb $38-$116/ton ~x</td>
</tr>
</tbody>
</table>
1.4.1 Tier 1 Proppants

Tier 1 ceramic proppants provide the highest strength because of their uniform size and shape. Some ceramic manufacturing companies even make hollow ceramic proppants to lower the specific gravity and allow further penetration into the fracture (see detailed analysis in section 5.2).

1.4.2 Tier 2 Proppants

Slightly lower strength Tier 2 resin-coated sands have lower size and shape regularity, but the resin coating provides for proppant embedment resistance and encapsulates fines. As described in the following sections, research shows that proppant fines and embedment contribute to a lower conductivity, a measure of proppants’ ability to provide a pathway for natural gas and oil from the shale reservoir to the pipe.

1.4.3 Tier 3 Proppants

Tier 3 proppants, sands, have the lowest conductivity but also the lowest cost. Sands typically have lower strengths and irregular sizes and shapes, both of which contribute to the lower conductivity. Table 5 also includes one market analysts price ranges for the three tiers of proppants.

Figure 6 shows general proppant selection recommendations based on formation closure stress as described by Rickman et al. (2008 and 2009). Geologists can predict rock formation closure stresses prior to fracturing with electro-magnetic spectrum analysis; generally formation closure stress varies with depth and rock composition. Literature shows that sand, a Tier 1 proppant, should generally feature in formations with closure strength less than about 6,000 psi, while high-strength bauxite, the upper echelon of Tier 3 proppants, can successfully fracture up to 20,000 psi formations.
As alluded to in Figure 6, operators use the closure stress at which proppants crush (defend as proppant crush strength) as one of a few measures to select proppants. Holistically, all the measures used to select proppants combine into a factor called conductivity. The following section explores quantitative and qualitative components to conductivity and emerging research on the well productivity benefits of using higher conductive proppants.

1.5 Proppant Conductivity
Proppant conductivity measures the proppants’ ability to keep the formation open to allow a pathway for oil and natural gas. Conceptually, reservoir impermeability (a function of geology, depth, etc.) drives the demand for higher conductivity proppants to maximize productivity of the well.

Table 6 details various proppant characteristics that affect proppant conductivity. The next section reviews academic research detailing a subset of the factors, while the
following section presents recent publications on wells using higher conductive proppants to increase well productivity.

Table 6: Six proppant factors contributing to proppant conductivity (Society of Petroleum Engineers, 1989)

<table>
<thead>
<tr>
<th>Factor</th>
<th>Effect</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir Demands</td>
<td>Stress transmitted from the earth to the proppant during fracturing crushes the proppant and may also cause embedment. Larger formation closure strength reduces proppant pack conductivity (or requires higher conductivity to maintain similar production).</td>
</tr>
<tr>
<td>1 Proppant Particle Size</td>
<td>Larger particles (e.g., 12/20 mesh\textsuperscript{ii}) provide greater conductivity at lower stress levels.</td>
</tr>
<tr>
<td>3 Proppant Strength</td>
<td>Stronger proppants can withstand larger closure stress and thus help maximize flow capacity, or retained conductivity.</td>
</tr>
<tr>
<td>4 Proppant Grain Shape</td>
<td>Well rounded proppants better distribute higher loads, thus increasing sphericity also increases conductivity.</td>
</tr>
<tr>
<td>2 Proppant Concentration*</td>
<td>Fracture conductivity increases exponentially with increasing concentration, to a limit after which too many proppants flood flow.</td>
</tr>
<tr>
<td>5 Embedment\textsuperscript{iii}.*</td>
<td>Proppant penetrates the fracture wall and therefore decreases the effective width and the conductivity.</td>
</tr>
<tr>
<td>6 Proppant Fines\textsuperscript{iv}.*</td>
<td>When fractures use too weak or brittle proppants, the surrounding rock crushes the proppants into smaller components called fines. Fines drastically affect resource flow rates; even the smallest amount of fines significantly reduces conductivity.</td>
</tr>
</tbody>
</table>

*: selected for literature review

\textsuperscript{ii} Mesh refers to the proppant diameter, measured by sifting through calibrated mesh. Lower size mesh correlates to a larger proppant diameter, e.g., when sifted, 12/20 proppants are larger than the size 12 mesh, but smaller than the size 20 mesh.

\textsuperscript{iii} Embedment occurs when proppants sink into the reservoir geology; an unfavorable outcome.

\textsuperscript{iv} Oil and gas drillers and operators refer to the small particles that break off of the proppant grain under fracture closure stress and temperatures as fines.
1.5.1 Proppant Concentration

In one study, engineers investigated the effects of proppant concentration on fracture conductivity by varying the concentration of 20/40 mesh sand under various closure stresses. \(^5^8\) Figure 7 shows a power relationship between concentration and conductivity (seen as linearity on the log-log plot) with an optimal proppant concentration around 100 lbs. per 1000 square foot of propped area. Increasing concentration beyond optimal results in rapidly plugged wells, and a number of studies\(^5^9,^6^0,^6^1\) suggest various surfactants\(^7\) to garner production benefits of higher proppant concentration to reduce the plugging effect seen in Figure 7.

![Figure 7: Fracture conductivity as a function of proppant concentration using 20/40 mesh sand (Halliburton Services, 1971) Image © Halliburton Services, 1971](image)

While ideally researchers can study the contributing effects to proppant conductivity as independent variables, a literature review of the study that included Figure 7 suggests that

\(^7\) Operators use surfactants, chemical additives, in many capacities, e.g., to increase flow viscosity.
Solomon Alkhasov  Commercializing a Resin-Coated Proppant

centration and proppant embedment (discussed below) have a dependency. The review argues Halliburton, a major operator, did not consider effects in soft formations where embedment could lower fracture conductivity significantly below the numbers in Figure 7.

1.5.2 Proppant Fines

Studies on proppant fines began as early as 1972 when Coulter et al. found that 5% of fines reduced proppant conductivity by 62%. Published in 1997, a study by Lacy et al. confirmed the results. Most recently, in a study published in 2010, Terracina et al. reviewed proppant fine production and its effect on conductivity with a focus on resin-coated proppants. Terracina et al. also found that proppant fines cause significant degradation in fracture conductivity by reducing the fracture width and lowering hydrocarbon flow to the well. Santrol, a resin-coated sand manufacturer, stresses in Figure 8 that increased resource production from fine encapsulation pays off the higher proppant cost (compared to uncoated sand).

![Figure 8: Santrol, a resin-coated sand manufacturor promotes the idea that its proppants will generate fewer fines and avoid sharp decreases in flow capacity (Santrol, 2014) Image ©Santrol, 2014](image-url)
1.5.3 Proppant Embedment

Terracina et al. writes that proppant embedment occurs when the proppant sinks into the surrounding rock reducing fracture width and conductivity, leading to a lower fracture flow capacity.\textsuperscript{67} Palisch et al. found proppant embedment to be a function of both proppant diameter and the Young’s modulus\textsuperscript{vi} of the reservoir formation, in Figure 9. The authors also write that embedment has a double effect on conductivity, both the decreased width (directly proportional), and altered fluid dynamic characteristics (exponentially proportional).\textsuperscript{68}

\begin{center}
\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{depth_of_embedment.png}
\caption{Depth of embedment varies with Young’s modulus of the rock and the diameter of the proppant (Palisch, 2012) Image © Palisch, 2012}
\end{figure}
\end{center}

\textsuperscript{vi} “Young’s modulus”, also referred to as the “modulus of elasticity”, or “elastic modulus” is a measure of the amount of force required to stretch the material. In its most basic form, Young’s modulus = stress/strain. Rubber has a low Young’s modulus, steel has a high one.
1.5.4 Explaining the Relationship between Embedment and Proppant Diameter

Yuanping Gao and his colleagues derived equations that describe proppant embedment relative to the proppants and geological formation’s mechanical characteristics. First, Gao et al. modeled the proppants as spheres. Equation 1 describes the contact area between two spheres squeezed with pressure P as shown in the left embodiment of Figure 10. The contact area is proportional to the ratio of multiplied radii over added radii, meaning the contact area is largest when two spheres of equal radii come into contact; when \((R_1 R_2)/(R_1 + R_2)\) approaches \(R/2\).

**Equation 1: Contact area, \(a\), between two spheres squeezed with pressure \(P\) (Gao, 2012)**

\[
a = \left(\frac{3}{4} P C_E \frac{R_1 R_2}{R_1 + R_2}\right)^{\frac{1}{3}}
\]

\[
C_E = \frac{1 - \nu_1^2}{E_1} + \frac{1 - \nu_2^2}{E_2}
\]

C \(_E\) captures the mechanical properties of the two spheres, \(\nu\), the poisson’s ratio \(^{\text{vii}}\), and \(E\), the modulus of elasticity. A smaller poisson’s ratio and a smaller modulus of elasticity contribute to a larger contact area.

---

\(^{\text{vii}}\) The “poisson’s ratio” is a measure of a material’s cross sectional contraction when stretched.
As shown in the right image of Figure 10, Gao et al. modeled embedment as the interface between a sphere with radius R and another sphere with infinite radius, a plate, and used the fundamental principles of two-sphere interference in Equation 1 to derive 3-dimensional proppant embedment, described further in Equation 2.

In Figure 11, Gao et al. extrapolate the deformation equations derived from two sphere interference into 2-dimensions (top) and 3-dimensions (bottom). In both cases the two plates, of known elastic modulus and poisson’s ratio (now indicative of reservoir geology) contract onto the stacked spheres.
Equation 2 describes proppant embedment as a function of packing efficiency ($K^\text{viii}$), proppant diameter ($D_1$), geological properties (thickness, $D_2$, elastic modulus, $E_2$, and poisson's ratio, $\nu_2$), and proppant mechanical properties ($E_1$ and $\nu_1$).

Equation 2: 3-dimensional embedment (Gao, 2012)

$$h = 1.04D_1(K^2p)^{\frac{2}{3}} \left[ \left( \frac{1 - \nu_1^2}{E_1} + \frac{1 - \nu_2^2}{E_2} \right)^{\frac{2}{3}} - \left( \frac{1 - \nu_1^2}{E_1} \right)^{\frac{2}{3}} \right] + D_2 \frac{p}{E_2}$$

Equation 2 takes the linear form of $y=mx+b$ with the slope as a function of the mechanical properties of both the proppant and formation, the pressure applied, and packing constant and the intercept as a function of the formation thickness, pressure, and formation elastic modulus. Using typical shale and sand mechanical properties\textsuperscript{72} and down hole conditions that Gao et al. used in their analysis (3mm thick shale and 40MPa down hole pressure), Figure 11 plots embedment over various proppant diameters.\textsuperscript{73}

![Figure 12: Embedment vs. proppant diameter](image)

\textsuperscript{viii} Gao et al. use “$K$” to describe packing efficiency. When the proppants lie close to each other, $K=1$, otherwise $K>1$. 
Switching from a 40/70 mesh to a higher diameter 20/40 mesh proppant, under the same down hole conditions, will increase proppant embedment by ~25% – doubly and negatively impacting conductivity through a decreased fracture width and reduced propped volume for fluid flow.

1.5.5 Brinell Hardness Number to Predict Embedment

In an effort to predict embedment susceptibility in various rock formations, Kurz et al discussed various geological tests on embedment including Brinell hardness, Rockwell hardness, microindentation, and others. The study concluded the Brinell hardness method is superior due to its ubiquity in the industry (leading to a wide array of data), and its methodology of using a larger-diameter sphere, which best represents proppants.\textsuperscript{74} Table 7 shows Brinell hardness values for some of the major formations.\textsuperscript{75} Haynesville shale and the Bossier formation have some of the lowest values, and are thus not promising for proppant embedment (indicating potential geographic segments for proppants which can resist embedment.) Stegent et al. published about embedment issues in the Eagle Ford formation, not listed in Table 7, but which has a Brinell hardness of 22.\textsuperscript{76}

Table 7: Average Brinell hardness values for various formations (Parker, 2009) \textit{Image © Parker, 2009}

<table>
<thead>
<tr>
<th>Formation</th>
<th>Brinell Hardness Number (BHN)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Woodford</td>
<td>43</td>
</tr>
<tr>
<td>Marcellus</td>
<td>32</td>
</tr>
<tr>
<td>Haynesville</td>
<td>18</td>
</tr>
<tr>
<td>Bossier</td>
<td>12</td>
</tr>
<tr>
<td>Barnett</td>
<td>80</td>
</tr>
<tr>
<td>Carthage Lime</td>
<td>82</td>
</tr>
<tr>
<td>Ohio Sandstone</td>
<td>34</td>
</tr>
<tr>
<td>Alabama Coal</td>
<td>15</td>
</tr>
<tr>
<td>Floyd</td>
<td>25</td>
</tr>
</tbody>
</table>
1.6 Effect of Proppant Conductivity on Well Production

The American Petroleum Institute (“API”) published the first proppant conductivity testing procedures in the 1980s to standardize fluid flow rates and test setups; however, the API intended to create a test for relative conductivity measurements, not absolute. As a precaution, the procedure came with a disclaimer: “CAUTION: The testing procedures in this publication are not designed to provide absolute values of proppant conductivity under down-hole reservoir conditions.”

Michael Vincent, in his article titled “Examining Our Assumptions – Have Oversimplifications Jeopardized Our Ability to Design Optimal Fracture Treatments?” argues that the conductivity tests adopted by the oil and gas industry, from the API 80s-decade standardization, do not accurately capture down-hole well conditions and consistently mislead drillers to choose non-optimal proppants for hydraulic fracturing. Vincent tabulated 200 published field studies in which drillers, operators, or service providers altered conventional proppant selection (in almost all cases using more expensive proppants with higher conductivity) and saw improved stimulation effectiveness – both more collected resources and a return-on-investment in using the higher quality proppant.

Vincent argues that a subset of down-hole complexities not captured in API’s conductivity test degrade effective proppant conductivity, requiring a higher quality proppant than suggested by Darcy flow regimens. For example, Vincent cites imperfect proppant distribution, where the API tests use a setup of 2 lbs./sq. ft. of a 20/40 proppant carefully leveled with a spatula to measure conductivity; 3–5 million lbs. of proppant used in an average horizontal frac are unlikely to settle within the frac in such an
idealized distribution. Post fracture analysis would more likely find a randomized proppant distribution, much like desert sand dunes.

To increase proppant conductivity in the 200 field studies, operators made the following adjustments to their baseline fracture design:

1. Increased proppant concentration.
2. Used larger diameter proppants.
3. Used stronger proppants.
4. Used higher quality, more uniformly sized proppant.

The studies cited by Vincent studied conventional and unconventional reservoirs (of varying permittivity), both domestic and international well sites, vertical and directional wells, and inland and marine fracking sites. To focus Vincent’s argument on the subsector of domestic unconventional horizontal wells, the following studies performed in the Bakken and Eagle Ford formations suggest utilizing higher conductivity proppants results in more resource collection. The studies show an aggressive return-on-investment on completing wells with higher conductivity proppants due to increased resource yields.

1.6.1 Bakken

As described by Rankin et al. in their 2010 review of horizontal well productivity in the Bakken region, oil and gas operators drilled more than 2,500 horizontal wells in the Bakken formation between 2001 and 2010 with a typical well costing $4–$8 million. The authors describe wells with 9,500’ laterals and 20–32 frac stages. In a comparison of seven wells drilled in the same study area, as shown in Figure 13, wells treated with higher conductivity ceramic proppants delivered 30–40% more cumulative oil than wells treated with lower conductivity Ottawa sand.
Another study in the Bakken shale compared production efficiency among 13 wells; data shown in Figure 14. Five wells comprised a test group that used 20/40 curable resin-coated sand (CRCS) while the other eight wells used 20/40 uncoated fine sand (UFS). As a result of the higher quality proppants, the five wells using CRCS had a 40% higher nine-month average production.
1.6.2 Eagle Ford

The Eagle Ford formation cuts between Houston and Austin, Texas, and follows shortly inland from the Gulf of Mexico towards the Mexican border. Based on Figure 15, the 50–1500 nanodarcy impermeable formations required advances in directional drilling and hydraulic fracturing to achieve economic resource withdrawal. Authors reviewing the region write that fracking in the Eagle Ford region started in 2008 with less than 20 wells in 2009; it grew to over 200 by 2011. Once operators set up necessary support personnel and equipment, activity skyrocketed to over 1,800 completed wells as of January 2012. Stimulating a well in the Eagle Ford formation (including proppant, water, chemical, and equipment cost), usually includes 25 fracturing stages each spaced 200–250 feet (for total horizontal lengths exceeding 5000’) and, in the longer deeper wells, costs upward of $5 million, or 60% of the total well cost.
Authors Pope, Palish, and Saldungaray report that well sites in the first few years of drilling had limited access to proppants as activity in the Eagle Ford region started alongside the nationwide boom in hydraulic fracturing. Proppant supply picked up, but “unfortunately most of the increase occurred in the uncoated sand segment, since opening new sand mines is much easier and quicker than building new RCS [resin-coated sand] or ceramic supply.”

To expose the benefits of using higher conductivity proppants, the authors published productivity reports of well sites using higher quality proppants, Tier 2 RCS or Tier 1 ceramic, instead of Tier 3 sand.

One year in, wells using higher conductivity proppants produced 35% more resources per well. Assuming $80 per barrel of oil and $4 per million cubic feet of natural gas, one year of production pays off transitioning to a more expensive proppant. The dotted lines plot the review of newer wells, where data exists only for six months. With feedback from existing well sites, drillers selected sites with higher fluid production where the data suggests “fracture conductivity becomes even more critical.”

In the six month comparison, the data suggests wells using proppants with higher conductivity produced 65% more resources with a $1.7 million incremental value.
Literature suggests early well proppant selection in the Eagle Ford Formation was based on availability at the time of stimulation, and high demand combined with low supply of high quality proppant drove up their cost. As activity transitions from transient decision making to steady state best practices, authors Pope, Palisch, and Saldungaray present data that supports the economic payoff of using higher quality proppants to increase well productivity.
2 Upstream Oil and Gas Industry

The oil and gas production value chain starts with the original owner of the mineral rights, usually an independent land owner. Operators (Chevron, BP, ExxonMobile, etc.) negotiate drilling rights to include an area based bonus, as high as $6,000 per acre in highly active regions,\(^9^0\) and royalties for top-line resource production, in some cases cited as 18–25%.\(^9^1\) In conjunction with the mineral rights, the operator negotiates drilling impact (pad size, road placement, etc.) with the landowner. Having legal rights to the land, an industry analysis report writes that the operators make the final decisions on “all facets of the well site, such as which drill bits to use, how much cement, and which technologies and services are economically viable for the project.”\(^9^2\) Before starting on the well, operators cross a return on investment confidence threshold based on geological surveying, production modeling, and geological analysis results. The geological analysis enables the operator to create a completion plan on resource withdrawal, including proppant type, fluid types, drilling plans, etc. Due to geographically widespread well sites and capital tied up in lease agreements, operators “often subcontract most well site work to other companies” to minimize capital costs and take advantage of cooperatively negotiated consumable costs (by service providers, as described below).\(^9^3\)

2.1 Subcontracted Work

Subcontracted work generally falls into two categories. First, operators contract a drilling company that owns the drilling rig and employs a team of operational staff and repairmen.\(^9^4\) The list of major US drilling companies includes Enescoc plc, Parker Drilling, Transocean, Diamond Offshore, and many more. Finally, the operator contracts service companies to provide technology expertise and any consumables. Service companies include Schlumberger, GE Oil & Gas, Baker Hughes, and many more.\(^9^5\) A
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typical off shore oil rig, for example, might have 120 people, of whom half are employed
by the driller, 10 by the lease holder, and around 50 by various service and supply
companies.\textsuperscript{96}

\textbf{2.2 Operator Behavioral Economics}
While HD Proppants plans to sell its resin-coated sand proppant to either service
contractors or operators, the engineers on the operator’s staff make the critical buying
decisions. The IBM sales model presents an analog for HD Proppants to consider. IBM
contributed to sales and marketing textbooks with its 1970s catch phrase, “nobody ever
got fired for buying IBM equipment.”\textsuperscript{97} IBM sales people engrained a notion of fear,
uncertainty, and doubt into the minds of buyers in IT departments who saw little
incentive in possible positive outcomes of buying from IBM competitors (the
technological upside of buying servers or computers from industry disrupters), and
instead feared penalization from taking the risk (due to server downtime, software
compatibility, etc.). Economist Thomas Covert argues effects similar to the IBM analog
(customers showing hesitancy to experiment with competitive options) exist in the
proppants industry, where Covert observed engineers on the operating teams did not
exhibit behavior consistent with a “reasonable” model of experimental risk taking.\textsuperscript{98}
Covert baselines “reasonable” experimental risk taking as the tendency for firms to learn
by doing, or increase productivity by increasing breadth of experience, as behavioral
scientists have studied in depth in the aerospace and automobile industries, but Covert
sees no evidence of this in his study of operators in North Dakota. Notably, Covert found
evidence of operators improving well production, but not by means of experimentation.
2.2.1 Well Site Operator Behavioral Economics

In “Experiential and Social Learning in Firms: The Case of Hydraulic Fracturing in the Bakken Shale,” Thomas Covert examines the behavioral learning of operators as they use production data to design optimal completion plans. Covert’s paper provides “one of the first empirical analyses of learning behavior in [operators] using operational choices, realized profits, and information sets.” In his findings, summarized below, Covert discusses operators’ hesitancy to experiment with operational procedures, specifically proppant volumes and by extension proppant types. An interview with Covert expanded and clarified findings in his paper and allowed an opportunity for Covert to propose strategies specific to HD Proppants as they navigate the industry.

2.2.2 North Dakota Industrial Commission

Covert starts his research with a unique dataset provided by the North Dakota Industrial Commission (“NDIC”) Department of Mineral Resources, where for $75 per year a subscriber can see the following data on all wells completed from 2005:

1. Well site operator

2. Well site location, given as longitude and latitude and translated to discrete townships

3. Horizontal length

4. Productivity logs

5. Pumping volumes including water and surfactants

6. Pumping mass including proppants

All operators must submit the data to the NDIC and Covert found that more recent submissions included details such as brand names, stimulation schedules, and fluid mix
Proportions. Covert based his studies on three different information sets. First, operators know their own data on wells. NDIC provides Covert with the information as to which wells an operator completed prior to starting a new one, as well as similarities between the new well and already completed ones. Second, operators must submit a report to the NDIC once they fracture a well, and subsequently, the regulator and tax authorities require monthly production reports on the well. However, the completion reports, permit filings, and sundry forms come with a six month non-disclosure, so the public, and competing well operators, can only see reports with a six month lag. Finally, a job typically has multiple non-operating participants – oftentimes competing operators who did not win the bid on the land with the pad, but own portions of land over the horizontal well – Covert found an average of three. However, all non-operating participants receive well production information without a six month lag. Covert collected publically available field mineral rights leases and scraped a website that records lease assignments to map the network of non-operating participants and operators involved with each well.

2.2.3 North Dakota Trends Implying Broad Industry Implications

During Covert’s study period, as many as 70 active firms operated rigs in North Dakota – the largest operator only had a market share of 13%, and the combined market share of the top five represented less than 50% of the wells. The dataset sampling patterns exhibited by a large number of operators gives Covert’s paper credibility to extend findings beyond the decision making process of a few, to that of an industry as a whole.
2.2.4 Thomas Covert’s Analysis

Covert categorized the NDIC well data from 2005 to 2011 (2,699 wells) into a model of four independent variables, location (latitude and longitude), fluid volume, proppant volume, horizontal length, affecting the main dependent variable, and production. Covert ran an ex-post analysis, determining whether operators made better fracking decisions over time using his model given today’s set of data. Also, Covert ran various ex-ante tests to analyze if firms optimized the fracturing design based on the data available at the time of fracking. Covert segmented the ex-ante tests between the three information sets, data based on the operator’s own experience, data the operator should know from competitive wells, and data the operator should know from experience as a non-operating participant in other wells.

2.2.5 Thomas Covert’s Findings

Covert’s economic study coupled with a deep industry analysis produced three profound conclusions:

1. Covert found no evidence of operators actively experimenting to improve well production. On the contrary, Covert found that operators were “willing to give up $0.62-1.11 in expected profits for a reduction of $1 in the standard deviation of profits.” With a typical horizontal well costing $8 million to drill and returning $22 million in production with $14 million in profits (and a $13 million standard deviation in the production returns), well operators preferred to reduce the standard deviation on returns rather than increasing possible returns.

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107 Ex-post refers to “after the event”, or an analysis of behavior impact on production in hindsight.
108 Ex-ante refers to “before the event”, or an analysis knowing only the information the operator would have known at the time the decision occurred.
2. Furthermore, between the 2,699 wells studied by Covert, the average well operator forgoes “$11.2 million in profits [per well] on an ex post basis and $5.8 million in profits [per well] on an ex ante basis, resulting in $14-30 billion in lost profits [Bakken shale total, over ~2700 wells and 70 operators].”

3. Finally, Covert introduced a new parameter, $\lambda$, bounded from zero to one where a firm with $\lambda=0$ sees no significance in data generated by others, a firm with $\lambda=1$ sees no significance in its own data, and a firm with $\lambda=0.5$ treats their own data and their competitors’ data equally. Of the eight firms analyzed in detail, six firms showed $\lambda<0.5$ and five of those six had a 95% confidence interval that did not include 0.5. The firms averaged to a $\lambda=0.36$. Covert concluded operators “appear to overweight data from their own operations relative to the data they observe from their competitors.”

2.3 HD Proppants Strategic Implications

Covert’s study of the operators’ behavioral decision making, in the context of the upstream oil and gas industry, creates profound implications for the commercial feasibility for HD Proppants:

1. While the final sale might occur to either a limited number of service providers, or a large number of operators, HD Proppants or its licensor would have to convince the lead operator, as the final decision maker of the well’s completion strategy, to buy its proppant.

2. In Covert’s analysis of the Bakken he found that the North Dakota drilling market had light concentration. Further to the point, Table 8 shows that the top 20 US operators (sorted by the number of directional wells drilled between January 1 and
April 1, 2014) only represent 50% of the market.\textsuperscript{112} The reverse income statement, section 3.3.1, suggests HD Proppants must sell into 20 wells a year to justify the smallest manufacturing unit, a single line producing 20 tons of resin coated sand per hour. Since an operator is unlikely to risk more than a small percent of wells on an experimental proppant, HD Proppants would certainly have to sell to more than one early adopter of its proppant (at least two, each having a portfolio the size of Chevron Corporation, shown in Table 8.)

3. Covert found operators showed “own-data bias,” weighing the completion trends garnered from their own results higher than those from competitors. While HD
Proppants might see a shorter sales cycle within a single operator (once well production data convinces the operator HD Proppants would not risk the well), HD Proppants should not expect a shorter sales cycle horizontally across multiple operators (selling into one operator will help little when selling into another. As one strategic implication, the data-bias suggests HD Proppants should overestimate initial capitalization requirements because of very long independent sales cycles.

4. Finally, Covert’s study reveals that operators show hesitancy in taking on any additional production risk and see more value in reducing well uncertainty rather than increasing well profitability. To frame Covert’s argument, Table 9 presents approximate average well economics for a vertical well (based on a well in the Wolfberry formation) and a horizontal well (based on wells in the Bakken formation). The first three rows show average well costs and proppant volume used in the wells. A $13 million standard deviation on a well with revenues of $22 million and costs of $8 million shows the speculative nature of the oil and gas industry. The following three lines show the savings from $100 per ton, $175 per ton, and $250 per ton proppant savings. Comparing the aggregate savings from a $250 per ton cost reduction in the proppant (an almost 50% reduction when estimating $500 per ton costs for resin-coated sands) to the total well returns (often over 200 times more) crystalizes Covert’s argument. While the proppants add significantly to the completion costs, well economics depend on lowering return risk, not completion costs.
Table 9: Approximate well economics and savings in Proppant Cost reductions, weighed as percentage of well returns

<table>
<thead>
<tr>
<th>Avg. Approx. Well Cost</th>
<th>Example Vertical Well</th>
<th>Example Horizontal Well</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avg. Approx. Well Returns (standard deviation)</td>
<td>$1.33 million</td>
<td>$8 million</td>
</tr>
<tr>
<td>Avg. Approx. Well Returns</td>
<td>$5.22 million</td>
<td>$22 million</td>
</tr>
<tr>
<td>Unpublished</td>
<td>$13 million</td>
<td></td>
</tr>
<tr>
<td>Avg. Proppants per Well</td>
<td>150 tons</td>
<td>2000 tons</td>
</tr>
<tr>
<td>$100</td>
<td>$22,500</td>
<td>.4%</td>
</tr>
<tr>
<td>$175</td>
<td>$26,250</td>
<td>.5%</td>
</tr>
<tr>
<td>$250</td>
<td>$37,500</td>
<td>.7%</td>
</tr>
<tr>
<td>$200,000</td>
<td>.9%</td>
<td></td>
</tr>
<tr>
<td>$350,000</td>
<td>1.6%</td>
<td></td>
</tr>
<tr>
<td>$500,000</td>
<td>2.3%</td>
<td></td>
</tr>
</tbody>
</table>

1: Based on vertical well analysis in Mack, 2013
2: Based on horizontal well analysis in Covert, 2014a
3: Based on horizontal well cost estimates in Hefley et al, 2011
4: Calculated from Mack, 2013 – for an NPV break even, the authors required a 2.3% production increase to justify a $120k cost increase.
5: Calculated from Covert, 2014a – author gave standard deviation of well output, converted using oil barrel prices for the same year, 2011, also from the author
6: Based on proppant use estimates in Clark, 2011

2.3.1 Industry Analysis Strategic Recommendations

Given the industry challenges HD Proppants needs to overcome, Thomas Covert presented two strategic recommendations for HD Proppants to pursue in the interview, based on his experience studying operator behavior in the Bakken shale:

1. Covert recommended scouring the NDIC data for operators who have already used alternate proppants to sand, perhaps to operators using CARBO Ceramic proppants (which he saw listed by name on a few reports) or even resin-coated sand proppants, and focusing on those operators as first customers.

2. Covert recommended focusing on the operators with a large geographic presence, either due to sheer corporate size, or because they are owned as subsidiaries of larger oil companies. Covert suggested larger operators with more wells might risk a higher number of wells on untested, or marginally used, lower cost
proppants (of comparable quality). He also surmised that larger operators might have a stronger focus on cost management; frequent well turn-over might give them enough data and confidence to employ lean cost cutting techniques (for example, purchasing a cheaper proppant) as a mechanism to boost corporate profits.\footnote{Karl-Heinz Schofalvi holds a B.A. in chemistry from Miami University and an M.S. in macromolecular science from Case Western Reserve University. He first invented the coating chemistry central to HD Proppants.}

3 Approach

HD Proppants has set out to commercialize innovative resin chemistry for manufacturing a resin-coated proppant. The project first started under the business model of coating a spent alumina base with the innovative non-epoxy and non-urethane petroleum pitch or furfuryl alcohol resins. HD Proppants sourced a spent alumina supply chain that was very cost competitive to synthetic ceramic proppants and even mined sand. However, initial lab testing, described below, identified that the spent alumina base had high size variation that was unacceptable for the popular mesh sizes in fracking. The current business model, as described in the financial models below, is based the innovative coating applied to uncoated sand.

3.1 Completed Lab Scale Testing

In September of 2013 Karl-Heinz Schofalvi\footnote{Karl-Heinz Schofalvi holds a B.A. in chemistry from Miami University and an M.S. in macromolecular science from Case Western Reserve University. He first invented the coating chemistry central to HD Proppants.} coated a spent alumina base proppant with a thermo-set (non-epoxy and non-urethane) coating using a lab-scale process proxy to the thermo spray capable rotary dryer process proposed for full-scale manufacturing. When testing the coated proppant, the lab determined that the coated proppants did not have consistent diameters; when separating the proppants into respective mesh sizes, the lab
did not have enough of a single mesh to perform testing. Furthermore, the lab found a majority of the proppant fell into the lowest of sieve sizes, a 70/140 mesh. Schofalvi attributed the inconsistent sizes to the spent alumina base; accordingly he gave up on alumina. HD Proppants pivoted to coating sand instead. Figure 16 shows 400x magnification photos from the 2013 testing.

![Figure 16: Spent alumina coated with HD Proppants proprietary coating](image)

3.1.1 Key Process Steps

Figure 17 details the proposed manufacturing process for HD Proppants’ one-part thermo-set coating. HD Proppants plans to use a modified rotary dryer, with a retrofitted thermal spray, to process the sand in three steps: first, pre-heating the sand; second, spraying the melted non-urethane non-epoxy coating (and additional additives); and third, processing the mixture at a third, higher, temperature to initiate cross-linking between the coating and sand. The key processing steps all occur in the modified rotary dryer. Since the rotary dryer represents both a key piece of process equipment and a significant cost, the following section analyzes the purchase and operation of a rotary dryer.
Figure 17: HD Proppants process using a single-part non-urethane, non-epoxy thermo-set coating

3.2 Rotary Dryer

Generally, ovens, dryers, and kilns differ in their maximum operating temperature. Having a rotary axis allows the material to evenly coat and prevents unwanted agglomeration. Figure 18 shows a cross-sectional view of a rotary dryer. The entire machine sits at a slight angle so sand, and its axial rotation, moves the material (on the left) to the product discharge (right).
Figure 18: Mechanical construction of a direct heat fired rotary dryer (FEечно International, 2014)  
Image © FEечно International, 2014

FEечно International, Inc. (“FEечно”) located in Green Bay, Wisconsin, makes three types of rotary thermal exchangers. Table 10 differentiates between the three product lines based on heating type (direct vs. indirect), presence of a refractory lining, operational temperature range, and general cost. An interview with a FEечно Sales Engineer helped HD Proppants estimate purchase, maintenance, and installation costs for a rotary dryer.117

Table 10: FEечно rotary thermal machines (Rittenhouse, 2014)

<table>
<thead>
<tr>
<th>Type</th>
<th>Refractory Lining</th>
<th>General Cost</th>
<th>Temp Range</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Rotary Dryer</strong></td>
<td>Direct</td>
<td>No</td>
<td>$</td>
</tr>
<tr>
<td><strong>Rotary Kiln</strong></td>
<td>Direct</td>
<td>Yes</td>
<td>$$</td>
</tr>
<tr>
<td><strong>Rotary Calciner</strong></td>
<td>Indirect</td>
<td>Yes</td>
<td>$$ $$</td>
</tr>
</tbody>
</table>

0°–700°F
0°–3,000°F
0°–3,000°F
3.2.1 Direct vs. Indirect Fired Dryers

In a direct fired rotary dryer or kiln (as pictured in Figure 18), the burner discharges flame coaxially to the dryer for direct heat transfer to the sand. Analogously, in an indirect fired rotary calciner, the heat flows from burners placed along the outside of the kiln. FEECO can strategically place burners along the length of the calciner, and vary activation, to control sand and solvent temperature much more precisely than in a direct fired kiln or dryer. Budgetary pricing will establish cost for an indirect fired calciner since it enables higher temperature control.

3.2.2 Refractory Linings

Given a projected 700°F top temperature for initiating cross-linking, the FEECO sales engineer warned that HD Proppants was on the cusp of needing a refractory lining to insulate the kiln. However, whether the final design will need a lining ultimately depends on the coating process specifics, which HD Proppants has not yet to determine.

The sales engineer encouraged HD Proppants to estimate costs using both cases. For diameters between 6’ and 12’, and 7.5” to 9” of lining, a brick refractory lining would add approximately $15,000 per meter. So lining on the estimated 125’ dryer adds an additional ~$600,000 in cost.

3.2.3 Estimated Dryer Size

Recently, Saint-Gobain issued a public permit application for a new ceramic proppant manufacturing facility, in which it described the coating operation. The Saint-Gobain facility processed calcined bauxite ore, a typical base for ceramic proppants. To produce a maximum feed rate of 29 tons per hour, the Saint-Gobain plant used a 132’ rotary dryer, 8’ in diameter. With slight interpolation to account for the projected 20 tons per hour
Solomon Alkhasov  Commercializing a Resin-Coated Proppant

feed rate, a 125’ long and 8’ diameter natural gas fired rotary dryer provides the basis for a first-pass estimate for budgetary pricing.

3.2.4 Purchase Costs

The FEECO sales engineer estimated a direct fired 125’ long, 8’ diameter rotary dryer would cost around $1 million. He explained that FEECO cannot manufacture indirect fired kilns nearly as long as 125’, because the length portions could not have burners with loadbearing supports, which would create a weak cantilevered design. FEECO has manufactured an indirect fired dryer as long as 75’, and 8’ in diameter, costing around $2 million. A 75’ long and 8’ diameter direct fired kiln would cost ~$700,000, or a third of the indirect fired alternative. The three times cost multiplier extends generally across analogous indirect and direct fired rotary dryers.123

3.2.5 Installation Costs

The FEECO sales engineer explained that quite a few of his customers have plants where the rotary dryer, or kiln, comprises about half of the total capital equipment cost for the entire plant. HD Proppants is as an example of such a plant. In this case, he has noticed a trend, which he now uses as a rule of thumb, where the FEECO capital equipment costs account for about 40% of total plant costs, including all installation. Table 11 summarizes estimated installation as comprising 25% of total capital expenditure costs.
### Table 11: Total plant installation costs in plants where the rotary dryer costs ~half of CAPEX

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>FEECO Dryer</td>
<td>$1 mill</td>
<td></td>
</tr>
<tr>
<td>Rest of CAPEX</td>
<td>$1 mill</td>
<td></td>
</tr>
<tr>
<td><strong>Total CAPEX</strong></td>
<td><strong>$2 mill</strong></td>
<td></td>
</tr>
<tr>
<td>FEECO Dryer/40%</td>
<td>$2.5 mill</td>
<td></td>
</tr>
<tr>
<td>Delta Installation</td>
<td>$500k</td>
<td></td>
</tr>
</tbody>
</table>
| Costs                |             | $500k = 25% of total CAPEX

#### 3.2.6 Control Systems

The estimated cost includes a dryer controller that has industry standard handshaking and communication protocols to connect to the plant controller. FEECO has developed an OEM partnership with Rockwell to provide full plant control installation as well as dryer integration. The sales engineer estimated plant-wide controls at around $100,000 with a slight efficiency (estimated at 10% to 20%) if HD Proppants purchases both dryer and plant controls from FEECO.\(^{124}\)

#### 3.2.7 Maintenance Costs

For a direct fired dryer with a refractory lining, the FEECO sales engineer bounded maintenance costs from $30,000 per year for traditional plants that keep the dryer in constant operation, to $200,000 per year for processes in early development stages, which include frequent shut downs and start-ups.\(^{125}\) Yearly maintenance for processes with constant shut downs may include refractory lining replacement, gear drive assembly tuning, and burner adjustments, but following industry best practices by keeping the rotary dryer in constant operation will minimize these costs. A geometric mean estimates about $80,000 in maintenance (8% of purchase price).
3.2.8 Operational Costs

The FEECO sales engineer uses a rule of thumb where a direct fired kiln requires 1,500 Btu of energy to evaporate one pound of water. Clearly the kiln has some inefficiency such as burner gas leakage, thermal radiation, convection to outside air, etc. The 1,500 Btu rule of thumb can help estimate rotary dryer system inefficiency by comparing the theoretical energy required to evaporate one pound of water against 1,500 Btu. The latent heat of water, 2,260 kJ/kg, defines the energy required to evaporate it. Assuming the inefficiency extends across materials, the inefficiency factor calculated using water, extended to the theoretical energy needed to heat sand to 700°F, estimates the approximate operational cost of the dryer. Equation 3 shows the estimated dryer system inefficiency of approximately 65%.

\[
\text{Equation 3: Estimating the dryer system efficiency} \\
(\Delta H_{vap,water} \times 1 \text{ lb}_{water}) = 1,500 \text{ Btu} \times n_{dryer} \\
\Delta H_{vap,water} = 2,260 \text{ kJ/kg} = 970 \text{ Btu/lb} \\
n_{dryer} \approx 65\% 
\]

\[
\text{Equation 4: Energy to coat one pound of sand} \\
(c_{p,sand} \times \Delta t_{room\rightarrow700\text{F}}) = \text{Operational Energy} \times n_{dryer} \\
c_{p,sand} = 930 \text{ J/kg°C} = .1776 \text{ Btu/lb°F} \\
\text{Operational Energy} = 2.2E5 \text{ Btu/ton} 
\]

\[
\text{Equation 5: Imperial to metric unit conversion for energy} \\
1 \text{ thousand cubic feet of natural gas}/1.023 = E6 \text{ Btu} 
\]

Assuming the dryer heats sand from room temperature to the maximum temperature in the patent, 60°F to 700°F, Equation 4 uses the specific heat of sand and the thermal efficiency of the dryer, calculated in Equation 3, to estimate 2.2E5 Btu of energy required to process per ton of sand. The US Energy Information Administration reported that industry in the state of Ohio spent on average $5.28 per thousand cubic feet on natural
gas in January 2014. Using Equation 5 to convert units reveals that processing one ton of sand through the rotary dryer costs approximately $1.20.

FEECO also pointed out that indirect fired kilns not only cost more, but also serve as less efficient heat exchangers. In an indirect kiln, burners need to heat the entire shell, which loses energy to radiation. In a directly heated dryer, with internal convective effects and external heat loss, burner temperatures of about 250°F will elevate particle temperatures to 1,000°F. Analogously, indirect kilns must heat to the full 1,000°F to reach particle temperatures of 1,000°F. Extending the sales engineer’s approximate efficiency comparison of one-to-four, processing sand in an indirectly heated kiln will cost about $4.80 per ton.

3.2.9 Rotary Dryer Costs from FEECO

Table 12 summarizes the three options for a rotary thermal exchanger from FEECO: directly fired dryer, refractory lined directly fired dryer, and an indirectly fired dryer.

<table>
<thead>
<tr>
<th></th>
<th>Direct Fired</th>
<th>Direct Fired, with Refractory Lining</th>
<th>Indirect Fired</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Purchase Cost</strong></td>
<td>$1,000,000</td>
<td>$1,600,000</td>
<td>$3,000,000</td>
</tr>
<tr>
<td><strong>Yearly Maintenance Cost</strong></td>
<td>$37,500$³</td>
<td>$80,000</td>
<td>$112,500$³</td>
</tr>
<tr>
<td><strong>Operational Cost</strong> (per ton)</td>
<td>$1.20$²</td>
<td>$1.20</td>
<td>$4.80</td>
</tr>
</tbody>
</table>

¹: Assuming HD Proppants could convert dryer diameter and length into a manufacturable length (<75’), otherwise HD Proppants will purchase two smaller indirectly fired dryers.
²: The refractory lining will add some thermal efficiency making the directly fired dryer slightly more expensive; however, minor difference is captured in the estimated cost analysis.
³: As an approximation, the maintenance cost is scaled using the purchase cost.
3.3 Reverse Income Statement

Business school professors Rita McGrath (Columbia School of Business) and Ian MacMillan (University of Pennsylvania Wharton School of Business) write about the reverse income statement, a tool for first-pass financial analysis, in “Discovery-Driven Growth: A Breakthrough Process to Reduce Risk and Seize Opportunity.” The reverse income statement breaks down costs and revenues of a smallest possible business unit to distill insights about financial feasibility, necessary scale, and capital intensity of a business model. Figure 19 diagrams the components to the reverse income statement analysis, as applied to HD Proppants. Sections 3.3.1 and 3.3.2 describe two ways the model calculates earnings before interest and tax (“EBIT”), once through an income statement and another time as a feedback loop using a required return-on-investment.

Figure 19: Two streams calculate EBIT in the reverse income statement – the left through an income statement, and the right using an expected return-on-investment analysis.
3.3.1 HD Proppants Reverse Income Statement

The reverse income statement model for HD Proppants starts with the minimum full-scale production unit – a manufacturing line which churns 20 tons of proppants per hour. HD Proppants chose 20 tons per hour as a first pass for financial modeling based on line capacity of sand processing equipment recommended by a manufacturing consultant hired for early stage plant design. First, the model captures total gross revenue as a function of average sale price per ton of proppant and monthly manufacturing capacity (which accounts for downtime). Second, to arrive at the contribution, the model subtracts direct variable costs from the gross revenues including sand, resin, and additives. Next, the model captures operating profit by subtracting direct costs, such as labor, maintenance, and capital equipment depreciation, from the contribution. Finally, EBIT is calculated by subtracting sales, general, and administrative (“SG&A”) costs from the operating profit.

3.3.2 Feedback Loop

The financial model has a feedback loop to determine if the EBIT calculated using an income statement sufficiently covers the required investment to start the plant. The feedback loop compares the calculated-EBIT with a required-EBIT, expected return-on-investment (“ROI”) times the investment. For modeling purposes, the ROI was set to 15%, so a $5 million investment (including working capital and capital equipment), requires an EBIT of $750,000. As described in Figure 19, if the required-EBIT ends up less than the calculated-EBIT, HD Proppants knows to reduce costs (variable, fixed, or SG&A) or increase revenues (higher capacity, or increased sales price).
3.3.3 Investment: Capital Equipment and Working Capital Needs

The model breaks down capital expenditures into nine line items (rotary dryer, thermal spray, control systems, silos, etc.) such that, including installation, add up to $3 million. Capital equipment costs contribute to the operational expense through depreciation (linear, five years). Additionally, the model approximates working capital needs to cover HD Proppants until it reaches breakeven. The working capital needs are calculated assuming it takes four months for HD Proppants to sell into a well, each month burning $80,000 to cover fixed overhead. It also takes into account cash flow, supplier, and customer terms. Ultimately, the model suggests HD Proppants needs to raise an additional ~$2 million to cover the business until cash flow breaks even.

3.3.4 Base-Case Key Line Items

Table 13 shows key line items from the base-case reverse income statement where HD Proppants must sell its resin-coated proppant for $207/ton to achieve a 15% ROI required-EBIT. Doing so, it would have built a business that generates ~$5 mill. in yearly revenues by selling 27,000 tons of proppants into ~14 horizontal wells. If indeed HD Proppants can raise the $5 mill. in financing, execute through the manufacturing nuances, and sell the resin-coated proppants at $207/ton, the model suggests HD Proppants can further duplicate the minimum business unit of 20 tons per hour into a much larger scale, limited either by financing, market saturation, or production material supply.

<table>
<thead>
<tr>
<th>Table 13: Key line items from the base-case reverse income statement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Expenditure</td>
</tr>
<tr>
<td>Working Capital</td>
</tr>
<tr>
<td>Monthly Burn Rate</td>
</tr>
<tr>
<td>Yearly Manufacturing Capacity</td>
</tr>
<tr>
<td>Sale Price to Meet Required EBIT</td>
</tr>
<tr>
<td>Yearly Revenues</td>
</tr>
</tbody>
</table>
3.3.5 Critical Model Variables

While many assumptions, calculations, and data points collectively build the model, all tabulated in Appendix 3, four critical variables will drive strategic insights from the reverse income statement:

1. Expected ROI: The model takes a 15% expected return on investment to drive a required-EBIT of $750,000 in the base case.

2. Sale Price: The model uses a variable sale price to arrive at the required EBIT. For the base case, to arrive at a $750,000 EBIT, the model shows HD Proppants needs to sell its proppant at $207/ton.

3. Sand Cost: The base case assumes HD Proppants procures sand at $100/ton, the average price in the market analysis. Potential strategic partnerships that lower the sand cost could make profound impact on a sale price to meet the required ROI.

4. Capital Expenditure Costs: Lowering the capital expenditure cost doubly effects the potential sale price – both by reducing the operational expenses (through depreciation) and by lowering the required-EBIT (since it’s derived through a percentage of investment, which includes capital equipment costs).

3.3.6 Scenario Analysis

Table 14 describes three scenarios that HD Proppants could explore, and their respective impact on the sale price required to meet an EBIT based on a 15% ROI. In one case, HD Proppants could reduce capital equipment costs (strategically achieved by partnering with a plant which has some of the capital equipment or by buying the equipment used). In another case, HD Proppants could attempt to procure sand at below market costs by partnering with a sand mine. The choice of cases reflects the fact that capital equipment
and sand costs critically drive the financial analysis. Finally, a third case models the combined effects.

While this section explores price point impact by lowering capital equipment or sand cost, HD Proppants should note model limitations. For example, lowering the capital equipment costs by virtue of a strategic partnership might require an additional royalty (not included in the model), or lowering cost by buying used equipment could increase maintenance costs or decrease up-time (neither captured in the analysis).

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Model Variation</th>
<th>Example Implementation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Reducing capital expenditure by 25%</td>
<td>Forming a strategic partnership with a plant which already owns equipment</td>
</tr>
<tr>
<td>2</td>
<td>Reducing sand cost by 25%</td>
<td>Forming a strategic partnership with a sand mine and procuring sand at below market cost.</td>
</tr>
<tr>
<td>3</td>
<td>Reducing capital expenditure and sand cost by 25%</td>
<td>A combination of scenarios 1 and 2.</td>
</tr>
</tbody>
</table>

Table 15 shows the resulting sale price from the three scenarios described above, and in Table 14. Reducing the sand price by 25% has a higher impact on the sale price than a similar reduction in capital equipment. Interestingly, a $25 reduction in sand cost does not correlate to a $25 reduction in sales price because of working capital requirements.
3.4 Strategic Implications

Reviewing HD Proppants’ approach to commercializing the resin-coated sand proppant reveals three key insights about the venture:

1. **Technical Risk:** As described in section 3.1.1, HD Proppants has yet to coat sand with the innovative resin. HD Proppants requires time and capital to complete lab-scale proof of concept testing. Additionally, void of any test data (conductivity, crush strength, specific gravity, etc.), HD Proppants has no baseline of its proppants’ performance relative to competitive resin-coated sands. As described further in Section 4, benefits-to-cost analyses, HD Proppants can currently only rely on its resin cost advantage when building its competitive advantage. Possible strategies to combat the technical risk include building lab-scale manufacturing and testing partnerships (either as strategic in-kind investments, or at reduced costs through off-hour testing), and to bring on board a team member with expertise in petroleum pitch or furfuryl alcohol based coating (perhaps from other industries).

2. **Capital Intensity:** The estimated $5 million required to open the plant will create capacity to manufacture 27,000 tons of proppant per year, or enough for roughly 14 horizontal wells (based on proppant estimates in Clark, 2011\(^{132}\)). According to a Baker Hughes report, operators drilled ~1,300 horizontal wells in 2013,\(^{133}\) so a $5 million investment buys approximately 1% market share in the proppants industry – an incredibly capital intensive endeavor. Furthermore, the technical and adoption risk (can HD Proppants execute? will anyone buy the proppant if they can?) reduces the favorability of the investment, especially since HD Proppants
cannot mitigate the adoption risk until the plant is built. Potential venture investment sources will require high ownership stake or, worse yet, pass on the investment all together. The analysis explored one strategy to combat the high upfront investment – forming partnerships with manufacturing plants already owning some of the capital equipment, and having excess space or human capital. Finally, The analysis was performed one a one-line plant. In subsequent financial modeling, HD Proppants should consider a second line for redundancy (if the first line goes down), and to buffer capacity.

3. **Licensing the Technology** – The reverse income statement analysis was created to analyze opening a plant. Instead, the capital intensity and technical risk profile suggests HD Proppants should view the venture from the opposite end of the spectrum, licensing the technology to either a player looking to enter the proppants industry (a coating company or sand mine for example) or existing proppant manufacturers looking for a competitive edge.

### 3.5 Patent Application

On October 23, 2012, HD Proppants filed utility patent application number 61717354 titled “Proppants for use in hydrofracking.”

On April 22, 2014, the US Patent and Trademark Office released the application into the public domain. As of May 2014, no formal patent examination on the novelty, non-obviousness, or usefulness of the application has occurred.

The main independent claim, claim 1, describes the method of manufacturing a proppant with the following key elements:

A. Inserting a plurality of particles into a heating device
B. Heating said particles to a first temperature
C. Heating a non-epoxy, non-urethane thermoset coating to at least its melting point, or dissolving said coating material in a solvent
D. Spraying said melted or dissolved non-epoxy, non-urethane thermoset coating into said heating device and onto said particles
E. Heating said particles to a second temperature higher than said first temperature

An additional 15 dependent claims limit the scope of the patent application, for example specifying a petroleum pitch coating (claim 12) or furfuryl alcohol coating (claim 3).

Appendix 4 visualizes all the claims, arranged by dependency with the main independent claim (1) on the left and each dependent claim stemming off to the right.

4 Benefits to Costs Analysis
A lack of performance test data to baseline strength, specific gravity, and conductivity of HD Proppants resin-coated sand to direct competitors, indirect substitutes, and alternatives, limits the scope of a benefits to costs analysis for HD Proppants. The following section analyzes two benefits of using resin-coated sand as opposed to ceramic or uncoated sand (applicable assuming HD Proppants can manufacture a resin-coated sand at least as good as the existing competition), and describes a framework to quantify the cost advantage of using the proposed non-epoxy and nonurethane (petroleum pitch or furfuryl alcohol) coating chemistry.

4.1 Encapsulating Fines
Terracina et al. found resin-coated sand less susceptible to fine production as the coating “encapsulates proppant fines and keeps fines from migrating through the proppant
Figure 20 compares uncoated ceramic proppants and resin-coated sand under similar 10,000 psi crush tests. Literature suggests the resin adds critical value in encapsulating fines to prevent the drastic decreased flow capacity described in section 1.5.2. However, research by Underdown et al. shows the resin coating encapsulation breaks down after around 10,000 psi, at which point fine production mimics uncoated ceramic proppants.

The CAT scan in Figure 20 (right) shows grain-to-grain bonding – a phenomenon caused by the resin coating on the proppants encapsulating the fines and preventing them from degrading fracture quality, in turn reducing well efficiency.

4.2 Reduced Proppant Embedment

Compared to uncoated sand and ceramic proppants, Terracina et al. claims that curable resin coated sands show less embedment into the shale compared to their uncoated sand counterpart because the coated grains bond together and form a pack that redistributes stress over a larger area reducing the pressure on any single point and resulting in less
embedment. The proppants industry broadly advertises resin-coated sand as the preferred solution to proppant embedment; for example, Momentive identifies proppant embedment resistance as the center point in its OilPlus promotional video describing its product line.

Figure 21, on the left, shows how resin coated proppants form bonds intermittent to the proppant and collectively the pack has more effective surface area to lower point pressure and embedment into the shale. In the right image, Momentive compares its resin-coated embedment resistant proppants to uncoated ceramic proppants, which Momentive claims embed farther into the shale, thus decreasing the pathway for natural gas.

4.3 Cost Benefits of HD Proppants Innovative Coating
Karl-Heinz Schofalvi started HD Proppants to exploit the cost advantage of using an industry byproduct, petroleum pitch, as the base chemistry for resin-coated proppants. The following section creates an order-of-magnitude framework to quantify the cost advantage of using the petroleum pitch compared to resin, urethane, or phenol-formaldehyde base chemistries.
4.2.1 Framework for Analysis

When cured, resin adds an incremental radial volume to the base sand. Using diameters from standard mesh sizes, 40/70 and 20/40, and assuming the resin adds 2.5% to the radius, 5% to the diameter (confirmed by Karl-Heinz Schofalvi as reasonable for first-pass analysis), Figure 22 calculates an approximate 10% volume of resin in resin-coated sand. Momentive’s EPON 828,\(^\text{139}\) an industry standard epoxy, published resin density of 10 lbs per gallon. Phenol-formaldehyde was found with similar resin density, and Schofalvi suggested HD Proppant resin will fall within the same range, so the 10 lbs per gallon was used as a constant across the cost analyses for the three chemistries.

![Figure 22: Resin cost contribution to a ton of resin-coated sand](image)

4.2.2 HD Proppants resin cost advantage

Bulk resin cost was the final variable necessary to calculate the cost advantage. Karl-Heinz Schofalvi secured pricing for petroleum pitch from a supplier, as well as epoxy pricing from a bulk distributor. Phenol-formaldehyde bulk pricing was estimated from a bulk distributor on Alibaba, priced at \(~$2500/\text{ton}\).\(^\text{140}\) Using the pricing estimates, and the assumed densities from Figure 22, Table 16 summarizes the estimated cost contribution
Solomon Alkhasov  Commercializing a Resin-Coated Proppant

of the three coating chemistries (Urethane or Epoxy, Phenol-formaldehyde, and HD Proppants) to a ton of resin-coated sand.

Table 16: Resin cost contribution to resin-coated sands selling at $200-$490 per ton

<table>
<thead>
<tr>
<th>Coating Chemistry</th>
<th>Approx. incremental cost to one ton of resin-coated sand</th>
</tr>
</thead>
<tbody>
<tr>
<td>Urethane or Epoxy</td>
<td>$70.00</td>
</tr>
<tr>
<td>Phenol-formaldehyde</td>
<td>$25.00</td>
</tr>
<tr>
<td>HD Proppants</td>
<td>$3.00</td>
</tr>
</tbody>
</table>

Based on the framework presented in Figure 22, using its innovative resin-coating chemistry should give HD Proppants ~$20 per ton cost advantage over resin-coated sand using a phenol-formaldehyde based resin chemistry. The analysis also concluded that urethane or epoxy two-part resin chemistries, hypothesized by HD Proppants as possible chemistries used by competitors in the industry, are not economically feasible for a resin-coated proppant as the phenol-formaldehyde competitors have a significant cost advantage of ~ $45 per ton.
5 Competitive Landscape
First, this section rewrites proppant qualities that operator’s use for differentiation, described in depth in section 1.5, into Outcome Driven Innovation terminology, a specific grammatical construct developed by Tony Ulwick to view not only direct competition (resin-coated sand) but also alternative choices and non-consumption. Sections 5.1.3 and 5.1.4 identify six companies already providing competitive and alternative proppants and section 5.2 describes one of them, Oxane Materials, in detail. As a recent entrant in a space dominated by large existing players, Oxane Materials set a growth strategy roadmap that HD Proppants can use in its own planning. Also, as indicated by ongoing fundraising and plant expansion, the team has convinced drillers to buy a high-cost alternative to sand with a return-on-investment sales pitch based on increased well-productivity; a pitch similar to the one HD Proppants will ultimately deliver.

5.1 Outcome Driven Innovation
Outcome Driven Innovation (“ODI”) encourages market analysis by desired function rather than classic market segmentation. Rival innovation thought leaders Clayton Christenson and Anthony Ulwick teach that customers hire products to solve a specific problem. Ulwick further developed this thinking into jobs-to-be-done statements and Outcome Expectations.

5.1.1 Job Statement
While customers buy many types of proppants, they have a unifying job-to-be-done: Prop reservoir geology during hydraulic fracturing e.g., in low permeability shale deposits.
5.1.2 Outcome Expectations

In response to this JTBD, key outcome expectations include:

1. Increase proppant pack conductivity of the fracture during hydraulic fracturing, e.g., by using geometrically uniform high strength proppants, by engineering a mixture which will suspend proppants further into the fracture, etc.

2. Increase flow rates after proppants are lodged in the shale, e.g., minimize the percentage fines or the likelihood of proppant embedment.

3. Minimize the time required for the proppant pack to reach ultimate bond strength in the formation, e.g., as measured from the moment the proppant reaches its destination in the shale formation.

5.1.3 Noteworthy Resin-Coated Sand Suppliers

HD Proppants should continue study of the resin-coated sand proppants offered by the following three companies, Atlas Resin, Santrol, and Momentive, as they fulfill many of the Outcome Expectations listed in 5.1.2.

1. Atlas Resin Proppants, based in Wisconsin, manufactures a series of resin-coated sand proppants, differentiated by their closure strength qualities. Atlas was formed from a strategic partnership with Badger Mining Corporation, a Wisconsin sand mining company selling into the proppant marketplace. With zero patents and no strategic acquisitions since formation (2007), of the six discussed competitors, Atlas Resin Proppants seems least focused on research and development.

2. Founded in 1976, Santrol owns over fifteen patents associated with proppants in hydraulic fracturing, and has published numerous papers in the Society of Petroleum
Engineering on resin-coated proppant selection and value proposition. In 1991 Santrol was acquired by Fairmount Minerals, Cleveland based sand mining company. Through the partnership with Fairmount Minerals, Santrol has cost effective access to sand, logistics systems, and company owned facilities. Santrol’s most recent product line was acquired from Soane Energy, Cambridge, MA, based material engineering firm, in May of 2013. Soane developed a resin coating which, when applied to sand, dramatically reduces its specific gravity. As described in detail in Oxane Material’s value proposition, section 5.5.2, a lower specific gravity allows for a proppant to flow deeper into the fracture, increasing effective contact area and resultant well productivity. Santrol advertises a specific gravity of 1.3 for the new proppant, compared to a 2.6 specific gravity of conventional sand proppants. Patent application PCT/US2012/053134 describes the self-suspending proppant (“SSP”) technology developed by Soane Energy.
Figure 23: Innovative resin-coated proppant technology allows the coating to swell 300% in water reducing specific gravity to nearly that of water and allowing full proppant suspension in water (Santrol, 2014) Image © Santrol, 2014

Santrol launched a new website (http://propelssp.com/) to document lab and well testing of the innovative low-specific gravity proppant; on the website, Santrol details how the proppant dramatically reduces specific gravity, described also in Figure 23.

3. Momentive, a Columbus, OH, based coatings company, manufactures a portfolio of resin-coated proppants. As shown in Figure 21, taken from a promotional video, Momentive heavily advertises its resin-coated sand proppants ability to reduce fine production and reduce proppant embedment. Strategically, Momentive captures the cost advantage of partnering with a resin manufacturer by likely sourcing phenol-formaldehyde at significantly lower prices than those used in the cost benefit analysis in Section 4.2.2.
5.1.4 Noteworthy Ceramic Proppant Suppliers

HD Proppants should continue study of the ceramic proppants offered by the following three companies, Oxane Materials, CARBO Ceramics, and Saint-Gobain, as they fulfill many of the Outcome Expectations listed in 5.1.2.

1. Oxane Materials is a recent new entrant in the proppants industry. Section 5.2 takes a deep dive into Oxane Materials’ value proposition of manufacturing a hollow ceramic proppant with a lower specific gravity. Oxane Materials grew from a startup in 2006 to today’s estimated 108 million pounds yearly capacity, or capturing 2% of the ceramic proppant market.

2. CARBO Ceramics (“CARBO”) is the largest supplier of ceramic proppants in the world. CARBO advertises a flagship new product, KRYPTOSPHERE, as capable of resisting 20,000 psi wells. KRYPTOSHEPRE “significantly exceeds the conductivity, compressive strength, and durability of the strongest bauxite proppants currently available on the market…which makes it the ideal choice for deep-water wells with high closure stress.”\textsuperscript{145} CARBO completed construction of its most recent manufacturing plant in 2013. Management anticipates operations will begin in Q2 of 2014, increasing total ceramic proppant capacity to 2 billion pounds per year (1 million tons per year and roughly 500 tons per hour if operating 8 hours per day for 250 days per year).\textsuperscript{146} Market analysts estimate 5.4 billion pounds of ceramic proppant consumed in 2014, which means CARBO captured about 40% of the ceramic proppant market.\textsuperscript{147} CARBO also sells resin-coated proppants, completing its most recent facility in 2012 with capacity of 400 million pounds per year (200,000 tons per year and roughly 100 tons per hour if operating 8
hours per day for 250 days per year). CARBO has plans for a second facility with capacity of 600 million pounds per year (300,000 tons), deferred until evidence of additional demand for its resin-coated proppant materializes.148

3. In 2001, Saint-Gobain, a French multinational corporation producing a variety of industrial and high-performance materials,149 completed the purchase of Norton Proppants. The sellers were Norton Company, producer of ceramic proppants exclusively from ExxonMobil since 1973 and commercially since 1977, and 50% shareholder, Alcoa, who invested in Norton Proppants in 1984.150 Saint Gobain Proppants is now the second largest ceramic proppant producer, with approximately 25–50% capacity of CARBO, or 250,000 to 500,000 tons per year.151

5.2 Oxane Materials
In 2006, Oxane Materials spun out of Rice University with a patent detailing a manufacturing process to produce low density ceramic proppants.152

5.2.1 Value Proposition
The founding team, Dr. Andrew Barron, technology founder from Rice University, and Chris Coker, CEO, identified that proppants generally exhibited “a fairly consistent strength-weight relationship.”153 Figure 24 shows a plot of closure stress against specific gravity. Existing proppants, graphed as red dots, follow a trend in which various technologies have increased proppant strength, but as strength increases so does the specific gravity. Oxane Materials has released four proppants breaking the strength to weight relationship: OxFrac 1.0, competitive in strength to sands and resin coated sands but with a 25% lower specific gravity, OxBall 1.0, competitive in strength to mid-grade
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ceramic proppants but a 17% lower specific gravity, OxSteel 1.0, competitive in strength with sintered bauxite high-end proppants but 19% lower specific gravity, and OxSteel 2.0, an iteration on the OxSteel 1.0, but with 26% lower specific gravity than bauxite proppants of the same strength.

Table 17: Oxane Materials proppant analysis

<table>
<thead>
<tr>
<th>Oxane Proppant</th>
<th>Strength, Specific Gravity</th>
<th>Proppant Type With Comparable Strength</th>
<th>% Lower Specific Gravity to Strength Comparable Proppant</th>
</tr>
</thead>
<tbody>
<tr>
<td>OxFrac 1.0</td>
<td>(6.5kpsi, 2.0)</td>
<td>Sand and resin-coated sand</td>
<td>25%</td>
</tr>
<tr>
<td>OxBall 1.0</td>
<td>(12kpsi, 2.7)</td>
<td>Mid-grade ceramics</td>
<td>17%</td>
</tr>
<tr>
<td>OxSteel 1.0</td>
<td>(15kpsi, 2.9)</td>
<td>High-grade bauxite</td>
<td>19%</td>
</tr>
<tr>
<td>OxSteel 2.0</td>
<td>(15kpsi, 2.65)</td>
<td>High-grade bauxite</td>
<td>26%</td>
</tr>
</tbody>
</table>

Figure 24: Oxane Materials breaks the strength/specific gravity curve set by existing industry proppants to make stronger and lighter proppants (Mack, 2013) Image © Mack, 2013

The vice president of technology, Mark Mack, and CEO, Chris Coker, discuss Oxane’s competitive advantage in a published paper titled, “Development and Field Testing of Advanced Ceramic Proppants.” As seen in Figure 25, Oxane Materials controls the manufacturing process to make uniformly hollow spheres as opposed to the random porosity of competitive ceramic proppants.
Figure 25: [L] Oxane Materials’ uniformly hollow sphere ceramic proppant; [R] Ceramic proppant with non-uniform holes and higher specific gravity (Mack, 2013) Image © Mack, 2013

The hollow center gives the Oxane Materials ceramic proppants low specific gravity.

Mack and Coker also write that the engineered process “results in very consistent size and strength distributions, and exceptional sphericity and roundness, which create direct benefits in both pack conductivity and proppant transport.”

5.2.2 Competitive Advantage

Oxane Materials has identified at least three advantages over competitive ceramic proppants, resin coated sands, and uncoated sands: 1) increased pack permeability due to uniform sphericity, 2) deeper settlement within a fracture due to a lower static friction coefficient, and, 3) higher coefficient of restitution. Oxane Materials’ higher conductive ceramic proppants transport further into the fracture – resulting in higher well productions as seen in field trials.

5.2.3 Uniform Sphericity

Bruce Meyer, Lucas Bazan, and Doug Wells set out to explain the effect of proppant diameter and shape uniformity on conductivity in a book chapter titled “Modeling of proppant permeability and inertial factor for fluid flow through packed columns.” The authors applied empirical testing and fundamental fluid theory to detect the following
relationship for an undamaged proppant pack, rearranged algebraically for order-of-magnitude analysis:

**Equation 6:** Proppant permeability in terms of the proppant diameter, porosity, slot width, and sphericity (Meyer, 2013)

\[
k_f = \frac{\phi^3 \Phi^2 d_p^2}{72 \lambda_m (1 - \phi)^2} \left( 1 + \frac{\Phi d_p}{3 (1 - \phi) w} \right)^{-2}
\]

\[
k_f = \frac{\phi^3 (d_p \Phi)^2}{72 \lambda_m (1 - \phi)^2} \left( \frac{3 (1 - \phi) \left( \frac{w}{d_p \Phi} \right)}{1 + (1 - \phi) \left( \frac{w}{d_p \Phi} \right)} \right)^2
\]

- \( k \equiv \text{proppant permeability} \)
- \( \phi \equiv \text{uniform porosity} \)
- \( d_p \equiv \text{diameter} \)
- \( w \equiv \text{slot width for hydraulic flow} \)
- \( \Phi \equiv \text{sphericity} \)
- \( \lambda_m \equiv \text{friction factor multiplier} = \frac{25}{12} \text{ from experimental results}^{157} \)

Figure 26: From [L] to [R] – Bauxite, sphericity = 0.90; Northern White Sand, sphericity = 0.73; Resin-Coated Sand, sphericity = 0.80; Brown Sand, sphericity = 0.50 (Meyer, 2013) Image © Meyer, 2013

The relationship in Equation 6 suggests that sphericity, \( \Phi \), has a magnified effect (\( k_f \sim \Phi^2 \)) on permeability, and ultimately, conductivity. Figure 26 shows various proppants sorted by descending sphericity left to right. Oxane Materials’ primary competitors, bauxite ceramic proppants, have a sphericity of 0.90. Oxane Materials manufactures proppants with a sphericity of 0.95, thereby delivering a little over 20% more proppant pack permeability (using Equation 6, assuming constant diameter, slot width, and porosity).
Increased permeability directly correlates to conductivity and ultimately results in more resource production.\textsuperscript{158}

5.2.4 Coefficient of Static Friction – Suspension Velocity

Oxane Materials studied the effect of static coefficient of friction on the settling velocity of proppants within a fracture. Thomas Camp published a paper on sediment settlement and the velocity required to move particles as a function of the coefficient of static friction.\textsuperscript{159} Scholars have discussed the relationship in depth, deciphering the variables with common ranges and analysis; however, the only insight from Equation 7 relevant to Oxane Materials is that the velocity is proportional to the square root of static friction, $\mu$.\textsuperscript{160} Decreasing the friction also decreases the scouring velocity, allowing a lower velocity to move more particles and results in proppants penetrating deeper into the fracture.

**Equation 7: Camp’s relationship of particle friction, $\mu$, to the scouring velocity (Camp, 1946)**

$$v_s = \sqrt{\frac{8 \times (1 - n) \times \mu (\rho_p - \rho_w) \times g \times d_p}{\lambda \times \rho_w}}$$

To derive the coefficient of static friction, Oxane Materials ran a proppant settling test through a funnel (see Figure 28) and measured the formation angle for various proppants. Figure 27 and Equation 10 describe the fundamental physics that relate the cone’s formation angle to the coefficient of static friction.\textsuperscript{161}
The two cases in Figure 27 analyze the forces on a block at the cusp of a forward force overcoming static friction. Equation 6 breaks up the forces in the horizontal axis to define the static friction in terms of the force required to push the block divided by the resistance force. In an ideal case, where friction approaches zero, the resistance force also approaches zero.

Equation 9 balances the two components of the weight against the resistance force and the limiting force.

**Equation 8:** A balance of forces on the horizontal axis, Figure 27 [left]

\[ \vec{f}_{\text{limiting}} = R \hat{\mu}_{\text{static}} \]

**Equation 9:** A balance of forces on the angled model, Figure 27 [right]

\[ \frac{W \sin \phi}{W \cos \phi} = R \vec{f}_{\text{limiting}} \]

Combining the two cases, Equation 10 describes the static force as a function of the incline angle.

**Equation 10:** Combining Equation 8 and Equation 9

\[ \tan \phi = \mu_{\text{static}} \]
Using the same principle as the block on an angled ramp, Oxane Materials funneled proppants through cone and measured the resulting angle of incline. Using Equation 10, Oxane Materials was able to back calculate the static coefficient of friction, $\mu$. As seen in Figure 28, Oxane Materials claims a 20% lower friction coefficient than competitive ceramic proppants and almost 40% lower than resin-resin coated sands.

![Figure 28: Oxane Materials claims a 20% lower friction coefficient than competitive ceramic proppants and almost 40% lower than resin-resin coated sands (Mack, 2013) Image © Mack, 2013](image)

Applying the settling velocity relationship in Equation 7, fluid velocities 20% lower than those for sand and 10% lower than those for conventional ceramic particles can mobilize Oxane Materials proppants. Due to the lower static coefficient of friction, theory dictates that Oxane Materials proppants should reach farther into the fracture to extend the fracture length and contact area and result in more oil and gas production.

5.2.5 Coefficient of Restitution

First developed by Sir Isaac Newton in 1687, the coefficient of restitution (“COR”) measures the elasticity of a material when bounced on a surface. A collision between two objects of perfect elasticity represents a COR of 1, while a COR of 0 occurs when an
object stops after collision.\textsuperscript{164} Equation 11 describes COR for an object bouncing off of a stationary object, like the floor, and in negligible drag, such as air.

\textbf{Equation 11: COR with one stationary object (Wikipedia 2014)}

\[ COR = \frac{velocity_{after\,impact}}{velocity_{before\,impact}} = \sqrt{\frac{bounce\,height}{drop\,height}} \]

Oxane Materials used Equation 11 on hundreds of proppant grains to compare the COR of their ceramic proppants to sand and conventional ceramic proppants.\textsuperscript{165} Figure 29 shows how Oxane used a high magnification 28 fps camera to record the particle trajectory and measure the bounce height.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{image}
\caption{Three frames of a proppant bouncing off of a surface using a 20X magnification 28 fps camera (Mack, 2014) Image © Mack, 2014}
\end{figure}

Professor Daniel Joseph from the University of Minnesota published two articles, one in 2001 and another in 2004, which estimated the COR in slickwater as 40\% of the COR measured in air.\textsuperscript{166,167} Using the conversion factor, Table 18 shows how Oxane Materials has a COR 15\% higher than sand and 22\% higher than conventional ceramics.\textsuperscript{168}

\begin{table}[h]
\centering
\begin{tabular}{|l|c|c|}
\hline
 & COR (Air) & COR (slickwater) \\
\hline
Oxane Materials & 0.67 & 0.27 \, 100\% \\
Sand & 0.58 & 0.23 \, 85\% \\
Conventional Ceramic & 0.53 & 0.21 \, 78\% \\
\hline
\end{tabular}
\caption{COR in air and slickwater for sand, conventional ceramics, and Oxane Materials hollow ceramic proppant (Mack, 2014)}
\end{table}
Theory dictates that the lower coefficient of friction and higher coefficient of restitution should propel the Oxane Materials proppants further into the fracture. Once lodged, the higher proppant pack permeability should keep the fracture open for increased well productivity.\footnote{169}

5.2.6 Field Trials

Oxane Materials published a 20-well study comparing well productivity using its proppants (10 wells) and competitive conventional ceramic proppants (10 wells). Figure 30 compares raw production values across all 10 geographically matched pairs of wells. Production varied by a factor of three across the 10 wells, thus indicating the highly speculative business of oil and gas drilling. Production in wells propped with Oxane Materials exceeded those completed using intermediate strength proppants in five of the pairs, approximately tied in three pairs, and was lower in two pairs.\footnote{170}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure30.png}
\caption{12-Month cumulative oil production across all wells (Mack, 2013) Image © Mack, 2013}
\end{figure}
While the operator captured meticulous data for Oxane Materials’ field trial, except in proppant selection, the wells were drilled to maximize profit, which dictated completion and stimulation differences between each pair and timeline variations, including:

- Some formations not breaking down within the well, causing abandoned zones
- Operator stimulating some pairs same day and others as much as six weeks apart
- Miscalculations or operational errors causing volumes above or below pump/pipe design

To further analyze the data, authors Stoker and Mack set up a statistical framework to capture the independent factors differentiating one pair of wells from another. The authors noted the complications were not unusual for the highly complex oil and gas industry, however, they did require statistical normalization.\textsuperscript{171} A multi-regression analysis assumed a linear relationship between various independent variables and the dependent oil production. The analysis had the form of Equation 12 with each variable having either a binary option (for example, proppant time) or an analog value (for example, timing differences). Key variables included:

- Proppant type
- Timing of pump instillation
- Stimulation strategy
- Location within the prescribed area

\textit{Equation 12: Linear regression analysis disaggregating variables to determine Oxane Materials’ impact on well productivity (Mack, 2013)}

\[ \text{production} = \text{base production} + C1 \times \text{Proppant Type} + C2 \times \text{Timing} + \ldots \]

Disaggregated from the other independent variables using the statistical analysis, the Oxane Materials proppant contributed to a 20% increase in well production, with a
variance “acceptable for typical oilfield field trials.” Based on the field trial reports, Table 19 summarizes average production, costs, and profitability of using Oxane Materials proppants.

Table 19: Average well economics using Oxane Materials in the 10 vertically drilled well pairs (Mack, 2013)

<table>
<thead>
<tr>
<th></th>
<th>Intermediate Strength Proppant</th>
<th>Oxane Materials</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td>$5.22 mill $1</td>
<td>100%</td>
</tr>
<tr>
<td>Cost</td>
<td>$1.33 mill</td>
<td>25%</td>
</tr>
<tr>
<td>Profit</td>
<td>$3.89 mill</td>
<td>75%</td>
</tr>
</tbody>
</table>

1. For an NPV to break even, authors required a 2.3% production increase to justify a $120k cost increase. Thus authors infer original production of $120k/2.3%.

2. Oxane Materials added $120k to the cost.

Oxane Materials charges drillers a premium to use its ceramic proppants. In the field trial report, Oxane Materials cited a cost premium of $120,000 for substituting their proppant into a vertical well. Market analysts estimate vertical wells using about 300,000 lbs of proppant, thus inferring Oxane Materials holds an $800/ton price premium over competitive ceramic proppants. In another Society of Petroleum Engineering article, Mark Mack suggests Oxane Materials adds $700,000 in cost to a well that uses 1,050 tons of proppants, inferring a price premium over competitive ceramic proppants of about $600 per ton.

5.2.7 Oxane Materials Financing

Since incubation, Oxane Materials has raised over $160 million in debt and equity with all but one identified investment coming from strategic sources. Oxane Materials received at least $2.5 million in early stage funding from one of its first strategic industry investors, Carrizo Oil & Gas, Inc. with $2 million in 2008 in exchange for warrants and preferential purchase rights on the proppant and an additional $500,000 as a convertible
Oxane Materials raised one institutional investment round from Energy Ventures, a venture capital fund from Norway; the size is undisclosed but it occurred at the end of 2008. Oxane Materials received a second round investment of $1.5 million from Energy Ventures in June of 2010.

Between 2008 and 2013, Oxane Materials raised around $140 million in equity financing from one venture capital fund, Energy Ventures, but otherwise relied on strategic investors such as BP Ventures, Chevron Ventures, Carrizo Oil & Gas, and ConocoPhilios Technology Ventures. Figure 31 plots fundraising over time and Appendix 1 features a detailed list of investment rounds.

Figure 31: Oxane Materials raised $160 million in financing since inception (Carrizo Oil & Gas, 2014) (Smith, 2013) (Xconomy, 2010) (Oil and Gas Investor, 2008)
5.3 Oxane Materials – Key Success Factors

In October of 2013, Oxane Materials was featured in an article published in the *Journal of Petroleum Technology*. The article identified the current Q3-2013 capacity at 1.8 million lb/month. Furthermore, the interview projected Q4-2013 capacity at 4 million lbs/month and Q4-2014 capacity at 9 million lbs/month. Assuming Oxane hit their 2013 projections and assuming an average sale price of $400/ton, Oxane Materials has built a company with $10 million in revenue, undergoing 100% growth in 2014 thus far – a very impressive outcome. Studying the commercialization pathway of Oxane Materials reveals three key strategic decisions that HD Proppants can emulate to increase their probability of success: strategic industry financing, early industry analysis, and industry recognition.

5.3.1 Strategic Financing Partners

First, Oxane Materials secured funding from strategic industry partners. As indicated by the $160 million raised by Oxane Materials, and also the financial analysis for HD Proppants, HD Proppants has embarked on a very capital intensive business that cannot earn sales before the deployment of millions of dollars to build manufacturing capacity. Raising capital from strategic partners, in a variety of partnership styles as described below, will extract additional value from the fundraising process and create incentivized partnerships to build early traction, thus increasing chances of commercial success.

Figure 32 organizes strategic partners into three tiers, ascending the pyramid in strategic value and descending in the number of options to choose from. Tier 1 partners, HD Proppants potential customers, add the most strategic value with product development feedback and potential purchase order commitments. Many of the recommended
strategies for HD Proppants included Tier 2 and Tier 3 companies, synergy and industry partners, that can reduce development costs and technical execution risk in exchange for company ownership, royalty, etc. Oxane Materials partnered with a Tier 3 strategic for early research and development, and, later, with a multitude of Tier 1 partners, as seen in Appendix 6.

![Figure 32: Organizing strategic investment for HD Proppants into three tiers, ascending with strategic value]

5.3.1.1 Tier 1 Partners

Table 20 lists the major oil and gas industry venture capital funds, at least five of which represent investment arms of oil and gas drilling companies, described in Figure 32 as a Tier 1 strategic partner. High venture activity from Tier 1 strategic investors serves as a positive indicator HD Proppants could seek funding from these sources.

Table 20: A list of oil and gas industry venture capital funds, at least five of which are investment arms of oil & gas drilling companies (London Environmental Investment Forum, 2013) Image © London Environmental Investment Forum, 2013
5.3.1.2 Case Study – FTS International
FTS International serves as an example of a company receiving strategic financing from its customers, oil and gas drillers. FTS International, a fully horizontally integrated hydraulic fracturing company, mines sand, produces resin coated sand, manufactures hydraulic pumps, assembles hydraulic fracturing machines, formulates the chemical blend used in the fracturing fluids, and transports the raw sand to job sites using its own distribution network. In 2010, Chesapeake Energy Corporation made a $100 million equity investment into FTS International, taking possession of 25.8% of the company. In 2011 Chesapeake Energy’s venture arm followed the 2010 investment with a $200 million equity investment, providing cash and Chesapeake Energy shares, and increasing the company’s ownership of FTS International to 30%. Chesapeake Energy was also one of FTS International’s main customers, accounting for, in dollars and as a percent of total revenues, $100 million (20%), $40 million (10%), and $110 million (10%) in 2008, 2009, and 2010.183

5.3.2 Early Industry Analysis
Oxane Materials succeeded in identifying its value proposition early in its business development, and recruited talent to build its industry expertise. Oxane Materials has the same value proposition now as listed in an Energy Ventures fund presentation dated 2008.184 The proppant manufacturing business does not lend itself to iterative pivots in value proposition and product feature-sets because of the large purchase orders, which creates a long and detailed sales cycle, and large cost in process changes (involving months of time and hundreds of thousands of dollars). Oxane Materials spent two years evaluating the commercial viability of its technology under the guidance of Dr. Andrew
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Barron, a Rice University professor who identified commercial markets ripe for technological disruption on at least five occasions previous to starting Oxane Materials. Furthermore, Oxane Materials recruited Mark Mack as Vice President of Engineering from his previous position at Schlumberger, one of the largest horizontal drilling completion companies. Incidentally, Mark Mack was hired shortly after Oxane Materials completed their first investment with Energy Ventures; at least three partners from Energy Ventures worked previously at Stumberger. Undoubtedly Mark Mack added deep industry experience and product development knowledge to Oxane Materials and the timing suggests the due diligence with Energy Ventures helped with the recruitment. Studying Oxane Materials suggests two strategies for HD Proppants:

1. HD Proppants should identify industry talent needs, for example resin coating development expertise. Partnerships with a Tier 1 or Tier 2 strategic can help with the recruitment efforts.

2. A partnership with a university for research and development can help with research and development, especially if HD Proppants can align with a professor or department focused on commercialization. Universities have various equity or royalty technology transfer policies, which HD Proppants should evaluate in detail; however, partnering with a university could help unlock non-dilutive funding to cover development costs.

5.3.3 Industry Recognition

Oxane Materials identified the Society of Petroleum Engineering (“SPE”) as a medium of disseminating well productivity results and publishing articles that describe their value proposition. SPE holds biannual fracturing technology conferences with conference
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papers aimed at both a technical base and non-technical audience. The articles are subsequently published for purchase online; the three articles posted by Oxane Materials documenting its value proposition and well productivity results cited in this study have received 400 downloads. HD Proppants should investigate similar avenues to distribute its value proposition and success stories to the players in the upstream oil and gas industry.
## Appendices

### Appendix 1: Directional Wells Drilled by Operators 1-Jan-2014 to 1-April-2014 (RigData, 2014)

<table>
<thead>
<tr>
<th>Company (1-40)</th>
<th>Directional Wells</th>
<th>% of All Directional Wells</th>
<th>Directional Wells as % of Company's Total Wells</th>
<th>Company (41-80)</th>
<th>Directional Wells</th>
<th>% of All Directional Wells</th>
<th>Directional Wells as % of Company's Total Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anadarko Petroleum Corporation</td>
<td>416</td>
<td>6.42%</td>
<td>98%</td>
<td>Penn Virginia Corporation</td>
<td>39</td>
<td>0.60%</td>
<td>100%</td>
</tr>
<tr>
<td>Chesapeake Energy Corporation</td>
<td>330</td>
<td>5.10%</td>
<td>100%</td>
<td>Kodiak Oil &amp; Gas Corp.</td>
<td>38</td>
<td>0.59%</td>
<td>100%</td>
</tr>
<tr>
<td>EOG Resources, Inc.</td>
<td>240</td>
<td>3.71%</td>
<td>95%</td>
<td>EXCO Resources, Inc.</td>
<td>36</td>
<td>0.56%</td>
<td>92%</td>
</tr>
<tr>
<td>Occidental Petroleum Corporation</td>
<td>208</td>
<td>3.21%</td>
<td>47%</td>
<td>Bonanza Creek Energy Operating C</td>
<td>36</td>
<td>0.56%</td>
<td>97%</td>
</tr>
<tr>
<td>Southwestern Energy Company</td>
<td>191</td>
<td>2.95%</td>
<td>99%</td>
<td>Cabot Oil &amp; Gas Corporation</td>
<td>36</td>
<td>0.56%</td>
<td>100%</td>
</tr>
<tr>
<td>Apache Corporation</td>
<td>173</td>
<td>2.67%</td>
<td>64%</td>
<td>Southwestern Energy Production C</td>
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<td>0.54%</td>
<td>100%</td>
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<td>Devon Energy Corporation</td>
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<td>88%</td>
<td>Swanson Companies, Inc.</td>
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<td>0.51%</td>
<td>94%</td>
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<td>Windsor Energy, Inc.</td>
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<td>0.48%</td>
<td>72%</td>
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<tr>
<td>Chevron Corporation</td>
<td>145</td>
<td>2.24%</td>
<td>47%</td>
<td>Yates Petroleum Corporation</td>
<td>30</td>
<td>0.46%</td>
<td>100%</td>
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<tr>
<td>Pioneer Natural Resources Company</td>
<td>136</td>
<td>2.10%</td>
<td>67%</td>
<td>Midstates Petroleum Company, LLC</td>
<td>30</td>
<td>0.46%</td>
<td>100%</td>
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<tr>
<td>ConocoPhillips Company</td>
<td>135</td>
<td>2.08%</td>
<td>79%</td>
<td>Hilcorp Energy Company</td>
<td>30</td>
<td>0.46%</td>
<td>94%</td>
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<td>Noble Energy, Inc.</td>
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<td>0.42%</td>
<td>100%</td>
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<td>Hess Bakken Investments II, LLC</td>
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<td>Consol Energy, Inc.</td>
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<td>100%</td>
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<td>Oasis Petroleum North America, LLC</td>
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<td>100%</td>
<td>Chief Oil &amp; Gas, LLC</td>
<td>27</td>
<td>0.42%</td>
<td>100%</td>
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<tr>
<td>Newfield Exploration Company</td>
<td>101</td>
<td>1.56%</td>
<td>94%</td>
<td>Tekton Windsor, LLC</td>
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<td>0.40%</td>
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<td>Gulfport Energy Corporation</td>
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<td>Murphy Oil Corporation</td>
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<td>100%</td>
<td>Petro-Hunt, LLC</td>
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<td>98%</td>
<td>Vantage Energy, LLC</td>
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<td>100%</td>
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<tr>
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<td>52</td>
<td>0.80%</td>
<td>100%</td>
<td>Sanchez Oil &amp; Gas Corporation</td>
<td>18</td>
<td>0.28%</td>
<td>100%</td>
</tr>
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<td>Ultra Petroleum Corp.</td>
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<td>0.73%</td>
<td>100%</td>
<td>Hunt Oil Company</td>
<td>16</td>
<td>0.25%</td>
<td>80%</td>
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<tr>
<td>Mewbourne Oil Company</td>
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<td>0.73%</td>
<td>100%</td>
<td>Freeport-McMoRan Oil &amp; Gas, LLC</td>
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<td>100%</td>
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<td>95%</td>
<td>Enduring Resources, LLC</td>
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<td>0.23%</td>
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6475 total directional wells
Top 120 operators drilled 5869
### Appendix 2: Income Statement, Base Case Financial Analysis

<table>
<thead>
<tr>
<th></th>
<th>Monthly</th>
<th>Annual</th>
<th>%</th>
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<tr>
<td><strong>Revenue</strong></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Proppant Sales</td>
<td>$460,000</td>
<td>$5,520,000</td>
<td>100%</td>
</tr>
<tr>
<td><strong>Total Gross Revenue</strong></td>
<td>$460,000</td>
<td>$5,520,000</td>
<td>100%</td>
</tr>
<tr>
<td><strong>Operational Expense</strong></td>
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<td></td>
</tr>
<tr>
<td>Variable</td>
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<td></td>
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<tr>
<td>Sand Cost</td>
<td>$224,000</td>
<td>$2,688,000</td>
<td>48.7%</td>
</tr>
<tr>
<td>Solvent Cost</td>
<td>$11,200</td>
<td>$134,400</td>
<td>2.4%</td>
</tr>
<tr>
<td>Coating Cost</td>
<td>$11,200</td>
<td>$134,400</td>
<td>2.4%</td>
</tr>
<tr>
<td>Dust Capture and Disposal</td>
<td>$14,246</td>
<td>$170,957</td>
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<td><strong>Total Variable</strong></td>
<td>$260,646</td>
<td>$3,127,757</td>
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<td><strong>Contribution</strong></td>
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<tr>
<td>Fixed</td>
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<tr>
<td>Operators</td>
<td>$10,000</td>
<td>$120,000</td>
<td>2.2%</td>
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<td>Maintenance</td>
<td>$20,000</td>
<td>$240,000</td>
<td>4.3%</td>
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<td>Depreciation</td>
<td>$50,333</td>
<td>$603,996</td>
<td>10.9%</td>
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<tr>
<td>Web Page</td>
<td>$90</td>
<td>$1,080</td>
<td>0.0%</td>
</tr>
<tr>
<td>Utilities</td>
<td>$9,032</td>
<td>$108,384</td>
<td>2.0%</td>
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<tr>
<td><strong>Total Fixed</strong></td>
<td>$89,455</td>
<td>$1,073,460</td>
<td>19.4%</td>
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<tr>
<td><strong>Operating Margin (GM)</strong></td>
<td>$109,899</td>
<td>$1,318,783</td>
<td>23.9%</td>
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<tr>
<td><strong>SG&amp;A</strong></td>
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<td></td>
<td></td>
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<tr>
<td>Lease Cost</td>
<td>$18,750</td>
<td>$225,000</td>
<td>4.1%</td>
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<td>Salary, Manager</td>
<td>$6,667</td>
<td>$80,000</td>
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<tr>
<td>Salary, Receptionist</td>
<td>$2,917</td>
<td>$35,000</td>
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<td>Salary, Sales</td>
<td>$7,083</td>
<td>$85,000</td>
<td>1.5%</td>
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<td>Benefits</td>
<td>$4,167</td>
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<td>Accounting</td>
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<td>Legal</td>
<td>$167</td>
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<tr>
<td>Telephone</td>
<td>$6,000</td>
<td>$72,000</td>
<td>1.3%</td>
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<tr>
<td>Internet</td>
<td>$1,080</td>
<td>$12,960</td>
<td>0.2%</td>
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<tr>
<td>Insurance</td>
<td>$2,083</td>
<td>$25,000</td>
<td>0.5%</td>
</tr>
<tr>
<td><strong>Total SG&amp;A</strong></td>
<td>$49,747</td>
<td>$596,960</td>
<td>10.8%</td>
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<tr>
<td><strong>EBIT</strong></td>
<td>$60,152</td>
<td>$721,823</td>
<td>13.1%</td>
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</table>
### Commercializing a Resin-Coated Proppant

**Appendix 3: Assumptions that Drive the Base Case Income Statement**

<table>
<thead>
<tr>
<th>Proppant Direct Costs</th>
<th>Model Assumptions</th>
<th>Notes</th>
<th>Source</th>
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<tbody>
<tr>
<td>Sand cost $100 Per ton</td>
<td>Leasehold Improvements $200,000</td>
<td>Office and warehouse infrastructure</td>
<td>Assumption</td>
</tr>
<tr>
<td>Solvent Cost $5 Per ton</td>
<td>Lease rate, industrial $7.00 Sq ft/yr. -- Industrial Space</td>
<td>Joe-Experience</td>
<td></td>
</tr>
<tr>
<td>Coating Cost $1 Per ton</td>
<td>Lease rate, office $11.00 Sq ft/yr. -- Office</td>
<td>Joe-Experience</td>
<td></td>
</tr>
<tr>
<td><strong>Total Direct Costs $106 Per ton</strong></td>
<td>Lease, land $3.00 Sq ft/yr. -- Land</td>
<td>Joe-Experience</td>
<td></td>
</tr>
<tr>
<td><strong>Proppant Revenue (Potential)</strong></td>
<td>Lease, Term 5 Years</td>
<td>Assumption</td>
<td></td>
</tr>
<tr>
<td>Hourly Capacity 20 Tons Per Hour</td>
<td>Area, Industrial 20,000 Sq ft/yr. -- Industrial Space</td>
<td>Joe-Experience</td>
<td></td>
</tr>
<tr>
<td>Utilization Rate 70%</td>
<td>Area, Office 5,000 Sq ft/yr. -- Office</td>
<td>Joe-Experience</td>
<td></td>
</tr>
<tr>
<td>Daily Capacity 112 Tons Per Day @ Utilization</td>
<td>Area, Production 10,000 Sq ft/yr. -- Land</td>
<td>Joe-Experience</td>
<td></td>
</tr>
<tr>
<td>Monthly Capacity 2240 Operating days per year</td>
<td>Lease Cost, Annual $225,000 Gross, less utilities</td>
<td>Calculation</td>
<td></td>
</tr>
<tr>
<td>Yearly Capacity 27,000 12 months per year @ Utilization</td>
<td>Office Equipment and Furniture $20,000</td>
<td>For employees</td>
<td>Assumption</td>
</tr>
<tr>
<td><strong>Per Ton Sale Price $207 Dollars</strong></td>
<td>Capital Equipment $3,000,000</td>
<td>Carry over, see break out</td>
<td>Calculation</td>
</tr>
<tr>
<td><strong>Total Daily Revenue $23,184 Dollars</strong></td>
<td>Web Design $2,500</td>
<td>Assumption</td>
<td></td>
</tr>
<tr>
<td><strong>Total Weekly Revenue $115,920 Dollars</strong></td>
<td>Working Capital $1,700,000</td>
<td>Assumption</td>
<td></td>
</tr>
<tr>
<td><strong>Total Monthly Revenue $460,000 Dollars</strong></td>
<td>Investment $5,000,000</td>
<td>Assuming Unamortized Leasehold Improvements</td>
<td>Calculation</td>
</tr>
<tr>
<td><strong>Total Annual Revenue $5,600,000 Dollars</strong></td>
<td>Expected ROI, per cent 15% Including cash</td>
<td>Mgt. Decision</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Operational Expense</th>
<th>Capital Equipment</th>
<th>Notes</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operator $60,000 Per year</td>
<td>Rotary Dryer $1,000,000</td>
<td>Direct Fired 125' Long, 8' Diameter Rotary Dryer</td>
<td>Soft Quote</td>
</tr>
<tr>
<td>Maintenance $240,000 8% of est. Equipment per year</td>
<td>Controls $100,000</td>
<td>Plant level under regulatory requirements</td>
<td>Soft Quote</td>
</tr>
<tr>
<td>Depreciation $604,000 Per year</td>
<td>Conveyors-warm $60,000</td>
<td>Joe-Experience</td>
<td></td>
</tr>
<tr>
<td>Webpage $90 Per month</td>
<td>Conveyors-room $40,000</td>
<td>Joe-Experience</td>
<td></td>
</tr>
<tr>
<td>Cap Ex Operational Costs $4,032 Per Month For dryer + rest of cap Ex 50% over dry</td>
<td>Silo $300,000</td>
<td>400 ton silo used = 45k</td>
<td>Calculation</td>
</tr>
<tr>
<td>Dust Capture and Disposal $6.36 Per Ton = 6% COGS less permit</td>
<td>Dust Collector $80,000</td>
<td>50,000 cfm from FCM</td>
<td>Joe-Experience</td>
</tr>
<tr>
<td>Building Operation Costs $5,000 Per month for building, electric + gas</td>
<td>Screener $125,000</td>
<td>40 tons in 2 hours Midwestern Industries</td>
<td>Joe-Experience</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>S.G.&amp;A</th>
<th>Fudge Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lease cost $225,000 Per year</td>
<td>Total $1,845,000</td>
</tr>
<tr>
<td>Salary, Manager $80,000 Per year</td>
<td>Installation $2,306,250</td>
</tr>
<tr>
<td>Salary, Receptionist $35,000 Per year</td>
<td><strong>Fudge Factor $3,000,000</strong> 25% more</td>
</tr>
<tr>
<td>Salary, Sales $85,000 Per year</td>
<td></td>
</tr>
<tr>
<td>Benefits 25% percent of salaries</td>
<td></td>
</tr>
<tr>
<td>Accounting + Bookkeeping $10,000 Per year</td>
<td></td>
</tr>
<tr>
<td>Legal $2,000 Per year</td>
<td></td>
</tr>
<tr>
<td>Telephone $500 Per month</td>
<td></td>
</tr>
<tr>
<td>Internet $300 Per month</td>
<td></td>
</tr>
<tr>
<td>Insurance $25,000 Per year – Joe to provide guidance</td>
<td></td>
</tr>
<tr>
<td>Depreciation 20% 5 Years</td>
<td></td>
</tr>
</tbody>
</table>
# Appendix 4: Working Capital Needs (of $1.7 million) Used in the Base Case Financial Analysis

<table>
<thead>
<tr>
<th>Months</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
<th>9</th>
<th>10</th>
<th>11</th>
<th>12</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wells Sold</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Cash Out</td>
<td>-</td>
<td>-</td>
<td>(216,032)</td>
<td>(428,032)</td>
<td>(216,032)</td>
<td>(428,032)</td>
<td>(216,032)</td>
<td>(428,032)</td>
<td>(216,032)</td>
<td>(428,032)</td>
<td>(216,032)</td>
<td>(428,032)</td>
</tr>
<tr>
<td>Cash In</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>414,000</td>
<td>828,000</td>
<td>414,000</td>
<td>828,000</td>
<td>414,000</td>
<td>828,000</td>
</tr>
<tr>
<td>Burn Rate</td>
<td>(80,000)</td>
<td>(80,000)</td>
<td>(80,000)</td>
<td>(80,000)</td>
<td>(80,000)</td>
<td>(80,000)</td>
<td>(80,000)</td>
<td>(80,000)</td>
<td>(80,000)</td>
<td>(80,000)</td>
<td>(80,000)</td>
<td>(80,000)</td>
</tr>
<tr>
<td>Total</td>
<td>(80,000)</td>
<td>(80,000)</td>
<td>(296,032)</td>
<td>(508,032)</td>
<td>(296,032)</td>
<td>(94,032)</td>
<td>531,968</td>
<td>94,032</td>
<td>531,968</td>
<td>94,032</td>
<td>531,968</td>
<td>94,032</td>
</tr>
<tr>
<td>Cumulative</td>
<td>(80,000)</td>
<td>(160,000)</td>
<td>(456,032)</td>
<td>(964,064)</td>
<td>(1,260,096)</td>
<td>(1,354,128)</td>
<td>(822,160)</td>
<td>(916,192)</td>
<td>(384,224)</td>
<td>(478,256)</td>
<td>53,712</td>
<td>(40,320)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Cost</th>
<th>Per Month</th>
<th>Value</th>
<th>Unit</th>
<th>Note</th>
<th>Cash Rqrd</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lease</td>
<td>$18,750</td>
<td>23%</td>
<td>Well Capacity</td>
<td>2000</td>
<td>Tons per well</td>
</tr>
<tr>
<td>Operators</td>
<td>$10,000</td>
<td>13%</td>
<td>Production Capacity</td>
<td>2240</td>
<td>Tons per month</td>
</tr>
<tr>
<td>Maintenance</td>
<td>$20,000</td>
<td>25%</td>
<td>Supply Chain Terms</td>
<td>30</td>
<td>Days</td>
</tr>
<tr>
<td>Building Operational Expenses (with benefits)</td>
<td>$5,000</td>
<td>6%</td>
<td>Operating Cost</td>
<td>$4,032</td>
<td>Per month</td>
</tr>
<tr>
<td>Accounting</td>
<td>$833</td>
<td>1%</td>
<td>Variable Cost</td>
<td>$106.00</td>
<td>Per ton</td>
</tr>
<tr>
<td>Legal</td>
<td>$167</td>
<td>0%</td>
<td>Sales</td>
<td>$207</td>
<td>Per ton</td>
</tr>
<tr>
<td>Phone/Internet</td>
<td>$590</td>
<td>1%</td>
<td>Sales</td>
<td>$414,000</td>
<td>Per well</td>
</tr>
<tr>
<td>Insurance</td>
<td>$2,083</td>
<td>3%</td>
<td>Total</td>
<td>$80,000</td>
<td>100%</td>
</tr>
</tbody>
</table>

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### Commercializing a Resin-Coated Proppant

#### Appendix 5: Patent Claims Arranged by Dependency

<table>
<thead>
<tr>
<th>Claim Number</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>A method of manufacturing a proppant comprising:</td>
</tr>
<tr>
<td>2</td>
<td>inserting a plurality of particles into a heating device;</td>
</tr>
<tr>
<td>3</td>
<td>heating said particles to a first temperature;</td>
</tr>
<tr>
<td>4</td>
<td>heating a non-epoxy, non-urethane thermoset coating to at least its melting point, or dissolving said coating material in a solvent;</td>
</tr>
<tr>
<td>5</td>
<td>spraying said melted or dissolved non-epoxy, non-urethane thermoset coating into said heating device and onto said particles;</td>
</tr>
<tr>
<td>6</td>
<td>heating said particles to a second temperature higher than said first temperature.</td>
</tr>
<tr>
<td>7</td>
<td>wherein the particles produced by said method are in a range from 400-600 microns.</td>
</tr>
<tr>
<td>8</td>
<td>wherein the particles produced by said method have a final apparent density in the range of 2.0 to 3.1 g/cc.</td>
</tr>
<tr>
<td>9</td>
<td>where the said particles produced by said method have a crush strength where 10% or less is crushed at a compression force of 7500 psi with a balance greater than 7500 psi.</td>
</tr>
<tr>
<td>10</td>
<td>wherein said particles include ceramic particles.</td>
</tr>
<tr>
<td>11</td>
<td>wherein the ceramic particles comprise aluminosilicate material from spent hydrocarbon cracking catalyst, hollow aluminosilicate spheres, silicon carbide flakes, natural mica flakes, chemically modified mica flakes, aluminum diboride flakes, boron nitride platelets, sodium silicate coated ceramic spheres, potassium ion modified mica flakes, alumina flakes, hollow alumina spheres, zirconia particulates, hollow zirconia spheres, sol gel or aerosol produced silica, or a mixture of two or more thereof.</td>
</tr>
<tr>
<td>12</td>
<td>wherein said non-epoxy, non-urethane thermoset coating includes petroleum or coal tar pitch or a combination thereof.</td>
</tr>
<tr>
<td>13</td>
<td>further comprising the step of diluting said non-epoxy, non-urethane thermoset coating.</td>
</tr>
<tr>
<td>14</td>
<td>wherein said heating device is a rotary tunnel kiln.</td>
</tr>
<tr>
<td>15</td>
<td>wherein said first temperature is between 100 and 200 degrees Celsius.</td>
</tr>
<tr>
<td>16</td>
<td>wherein said coating comprises a carbon based thermoset coating.</td>
</tr>
<tr>
<td>17</td>
<td>wherein said coating comprises furfuryl alcohol.</td>
</tr>
<tr>
<td>18</td>
<td>wherein said non-epoxy, non-urethane thermoset coating is sprayed into said heating device while said particles are moving.</td>
</tr>
<tr>
<td>19</td>
<td>wherein said non-epoxy, non-urethane thermoset coating is sprayed into said heating device while said particles are at a temperature between 40 and 60 degrees Celsius. Or where the coating is dissolved before spraying onto the particle surface.</td>
</tr>
<tr>
<td>20</td>
<td>wherein said second temperature is between 300 and 400 degrees Celsius.</td>
</tr>
</tbody>
</table>
### Appendix 6: Oxane Materials Investment Rounds

<table>
<thead>
<tr>
<th>Oxane Materials, Inc. expects to receive $65 million in funding.</th>
<th>5-10-2013</th>
<th>Private Placement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oxane Materials, Inc. announced an equity round of funding for gross proceeds of $65,000,000 on May 10, 2013. The minimum investment accepted from any outside investor is $2. Pareto Securities Inc. will act as the placement agent to the company. The company will pay sales commissions of $630,000. As of May 24, 2013, the company received $54,404,643 from 17 investors in its first tranche. <strong>Source:</strong> Capital IQ Transaction Database</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Oxane Materials, Inc. expects to receive $6 million in funding.</th>
<th>11-12-2012</th>
<th>Private Placement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oxane Materials, Inc. announced that it will raise $6 million in funding on November 13, 2012. The company will accept a minimum investment of $1 from each investor. The company will issue convertible debt in the transaction pursuant to Regulation D. As of November 28, 2012, the company had raised $2,937,571 in funding from four investors. On February 20, 2013, the company announced that it will raise an additional $12,352,942 in this transaction from two investors. The total proceeds raised will be $18,352,942. As of March 4, 2013, the company raised an additional $12,352,942. <strong>Source:</strong> Capital IQ Transaction Database</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Oxane Materials, Inc. raises $5 million in private offering.</th>
<th>10-15-2012</th>
<th>Debt Financing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oxane Materials, Inc. has raised $5 million in debt offering. The company will use the funds for operating expenses including ordinary course compensation of officers and directors. <strong>Source:</strong> Datamonitor NewsWire</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Oxane Materials, Inc. expects to receive $50 million in funding.</th>
<th>1-08-2012</th>
<th>Private Placement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oxane Materials, Inc. announced that it will raise $50 million in its round of equity funding on January 9, 2012. As part of the round, the company will issue equity securities to the investors pursuant to Regulation D of the Securities Act. The company will accept a minimum investment of $1 from any outside investor. Dundee Securities Ltd. will serve as placement agent and will receive $500,000 as sales commission. Sales commission will be based on a formula to be determined at completion of transaction. <strong>Source:</strong> Capital IQ Transaction Database</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Oxane Materials, Inc. expects to receive $7.44 million in funding. 10-31-2011 Private Placement

Oxane Materials, Inc. announced on October 31, 2011, that it will raise $7,441,497 in funding. The company will accept a minimum investment of $1 from each investor. The company will issue convertible debt to the investors. As on November 18, 2011, the company raised $4,047,000 from six investors. On September 28, 2012, the company announced that it will raise $5 million in additional funding, thus bringing the aggregate proceeds to be raised in the transaction to $12,441,497.

Source: Capital IQ Transaction Database

Oxane Materials, Inc. expects to receive $9.5 million in funding. 12-22-2010 Private Placement

Oxane Materials, Inc. announced that it will raise $9.5 million through the issuance of equity shares on December 22, 2010. As of December 30, 2010, the company raised $5 million in funding from one investor. As of February 10, 2011, the company raised $7,994,954 from 21 investors.

Source: Capital IQ Transaction Database

Oxane Materials, Inc. expects to receive $12 million in funding. 2-22-2010 Private Placement

Oxane Materials, Inc. announced it will receive $12 million in a round of funding on February 23, 2010. The company will issue common shares pursuant to Regulation D under the Securities Act. An investor can invest a minimum of $1. As of March 9, 2010, the company has raised $10 million in funding led by existing investor Energy Ventures AS. The round included participation from a single investor. As of April 19, 2010, the company has raised $11,441,690 in its series B round of funding from 24 investors in the transaction.

Source: Capital IQ Transaction Database

Oxane Materials Inc. has received funding from Energy Ventures. 12-10-2008 Private Placement

Oxane Materials, Inc. announced that it has raised a round of funding from Energy Ventures AS on December 11, 2008. Jim Sledzik served as the placement agent for Energy Ventures AS. The financial terms of the transaction were not disclosed.

Source: Capital IQ Transaction Database

Oxane Materials has received $1.20 million in funding. 3-07-2007 Private Placement

Oxane Materials, Inc. announced that it has raised $1.2 million in funding on March 7, 2007.

Source: Capital IQ Transaction Database
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