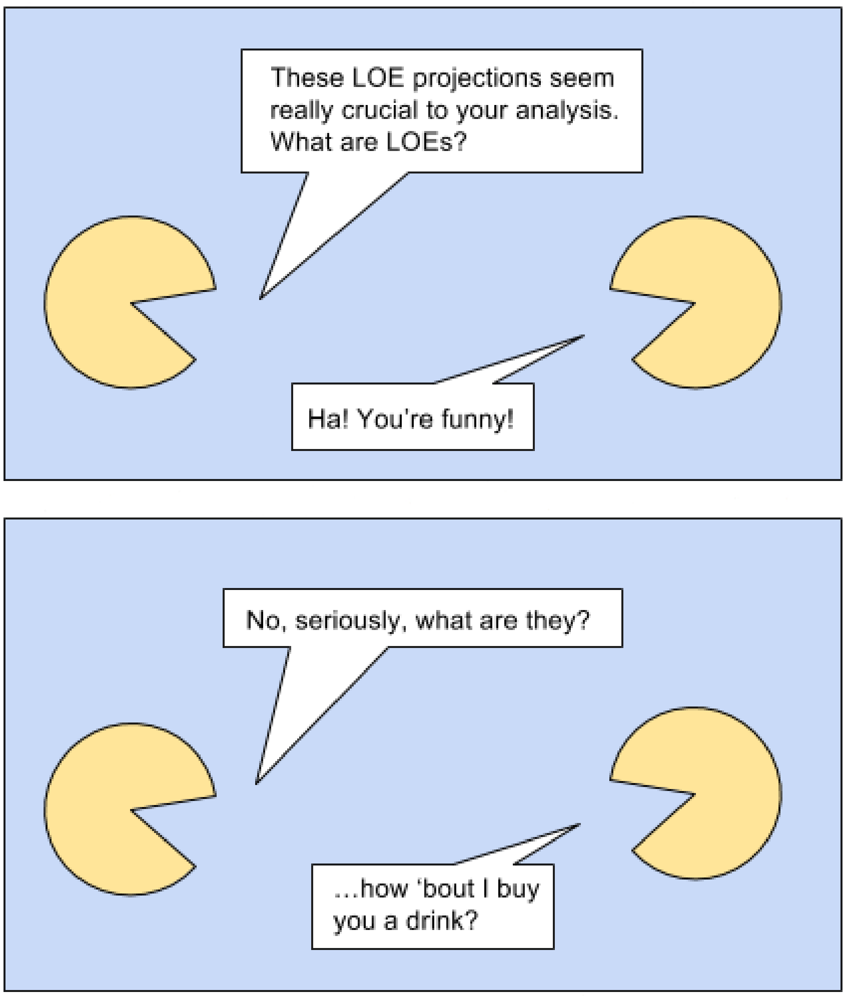
The ABCs of LOEs



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In today's environment, it's not enough to hedge against oil price volatility. Operating expenses are volatile, too. Add to that the lack of a futures market for operating expenses and the fact that survival now depends on razor-thin margins, and it becomes clear how it is more important than ever to understand the "lease operating expenses" (LOEs) so frequently cited by E&P executives. What do LOEs consist of? How do they react to changing commodity prices, production volumes, and other factors? This paper focuses on answering these questions.

What Are Lease Operating Expenses?

<u>An Engineering Perspective</u>

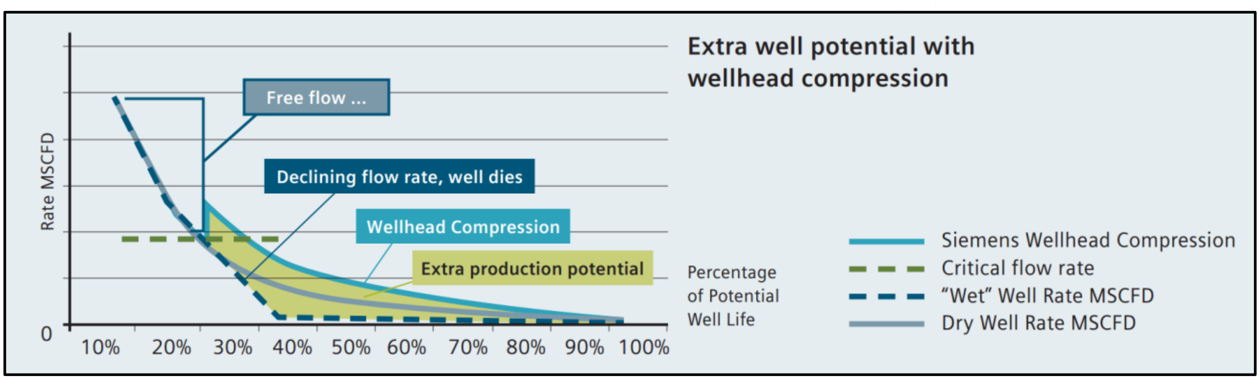
First, consider the following engineering/economic definition:

> Lease operating expenses (LOEs) are the direct costs incurred in order to maintain production at *a rate consistent with the capital investment history of the underlying well*.

To illustrate what we mean by the italics above, consider a ten-year-old natural gas well that produces into a high-pressure gathering system. The owner of that well might want to install a "wellhead compressor" to reduce the pressure on the well and, in turn, increase the well's production rate. The initial investment would be considered a development cost, but the ongoing fuel and maintenance expenses would be recorded as lease operating expenses. If these costs are not paid, the benefits of the initial investment are lost as the compressor cannot function without fuel or maintenance. This is what we mean by "costs incurred in order to maintain production at a rate consistent with the capital investment history of the underlying wells."

Figure 1 illustrates the improvements from the installing a wellhead compressor.

Figure 1



Source: http://w3.siemens.com/markets/global/en/oil-gas/PublishingImages/applications/onshore-production/Extending_value.pdf

Note that, in Figure 1, the production rate after installation (the light blue solid line) is not fixed. Rather, just like the rate before the installation (dashed blue line), it is a gradually declining rate. In this sense, it might help to think of lease operating expenses as the expenses required to keep a well on the appropriate decline *path* given its capital investment history.

A Legal Perspective

Now let's consider a legal definition of LOEs:

> Lease operating expenses are those costs incurred or incident to bringing the subsurface minerals (oil and gas) up to the surface and converting them to marketable products. *LOEs* ***do not*** *include any transportation expenses incurred to move these products from the lease to off-lease markets where they can be sold*.

According to oil and gas law and custom, the owner of the mineral rights is typically granted a royalty interest in the wells drilled within the boundaries of the lease. In most states, the default rule (if the parties do not specify otherwise) treats the royalty interest as a promise from the producer to the mineral rights owner to give the mineral rights owner a "cut" of the oil and gas produced from the lease. However, it *does not* include a promise to transport that oil and gas from the lease to a market where they can be sold.

In other words, the royalty owner takes legal title (ownership) at the point where the oil and gas come to the surface of the lease. At that point, in theory, it's up to the royalty owner to get the oil and gas to market. In practice, however, the E&P company usually transports the royalty owner's oil and gas, but begin to split the costs proportionally with the mineral rights owner. This gives rise to royalty owner lawsuits where the key issue is determining what should and should not be considered a lease operating expense. In this context, "production" and "post-production" costs are often used in place of LOE and non-LOE expenses, but the concepts are the same.

Bringing It All Together

We now have two definitions: one engineering/economic and one legal. As you can imagine, for the most part, these definitions overlap and largely find themselves in agreement. Expenses *necessary* to keep a well producing at a level consistent with its capital investment history will generally be expenses incurred by production equipment and machinery located within the lease boundary itself, which will generally be consistent with what is required to bring the oil and gas to the surface, short of transporting it to market.

However, there are situations where these two definitions can conflict. For instance, consider large compressor station that lowers the pressure for a gathering system connected to many leases. Such a compressor station would have the effect of enhancing the production profiles (paths) for all of the connected wells. Its fuel expenses would therefore qualify as LOEs under the engineering/economic definition.

On the other hand, if the same compressor station is necessary for the gathering system to feed into a high-pressure transportation pipeline, then the legal definition might suggest the fuel expenses are more of a "transportation" or "post-production" expense and not a lease operating expense.

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Recognizing these potential conflicts, these definitions should not be treated as rigid rules, but as guiding frameworks. They will help give you a sense of what is most likely included in LOEs and on what basis, but due to the competing purposes behind drawing LOE/non-LOE distinctions, you can never be 100% certain.

To illustrate this last point, consider Figure 2, which contains a non-exhaustive list of the possible components of LOEs.

Figure 2

Water [procurement]	Gas Marketing Service & Repair	Compressor Rentals
Trucking & Land Transportation	Safety & Supplies	Ad Valorem Tax
Boats, Water Transportation	Pollution Control	Production/Severance Tax
Helicopter, Air Transportation	Compressor Parts	Federal Fuel Use Sales Tax
Company Labor	Surface Repairs & Maintenance	State Fuel Use Sales Tax
Payroll Burden	Groceries & Food	Prod./Severance Tax (20% prop.)
Employee Pension	Other Rents	Field Expense
Contract Labor	Measurements & Testing	Facility Operations
Consultants & Professional Service	Communications	Net Profits Interest
Meals/Entertainment	Road & Location Maintenance	Overhead
Other Employee Expense	Controllable Equipment	District Expense
Chemicals & Treating	Subsurface Repairs & Maintenance	Miscellaneous
Supplies & Tools	Well Workover	Nonoperating Joint Cost
Gathering	Well Services	Advances to Operators
Transportation	Abandonment	Cutback on Insurance
Fuel & Electric	Legal	Charges to Joint Owners
Saltwater Disposal	Equipment Rental & Service	

Source: *Fundamentals of Oil & Gas Accounting*, 5th ed., Charlotte J. Wright and Rebecca A. Gallun, 2008.

Looking at Figure 2, we can ask ourselves questions and apply our definitions and common sense to sort out what is and what is not likely included in LOEs.

Here are some examples of this self-directed Q&A process:

> Will an onshore well have helicopter and air transport charges in its LOEs? No, those are only needed for offshore wells to rotate the crews. I suppose the crews are necessary, though, to keep production going, so it would be a part of LOEs for an offshore well.
>
> Would the legal fees from a shareholder lawsuit be considered an LOE? Probably not. What about legal fees from a dispute with the royalty owner? Probably yes. The company can't keep producing from the well if a court issues an injunction ordering them to stop.
>
> What about transportation and gathering fees? Well, in general, they really shouldn't be LOEs. But perhaps the gathering system includes a compressor station, like we mentioned earlier, that improves the production capacity of the wells. Or maybe this

company has unique contracts that allow it to allocate these costs back to the leases. Or maybe, if they don't, they're just taking the risk of opening themselves up to lawsuits.

Forecasting LOEs

Now that we know what LOEs are (or at least have a framework for making educated guesses), the next thing to figure out is how to forecast them (or place them within reasonable limits).

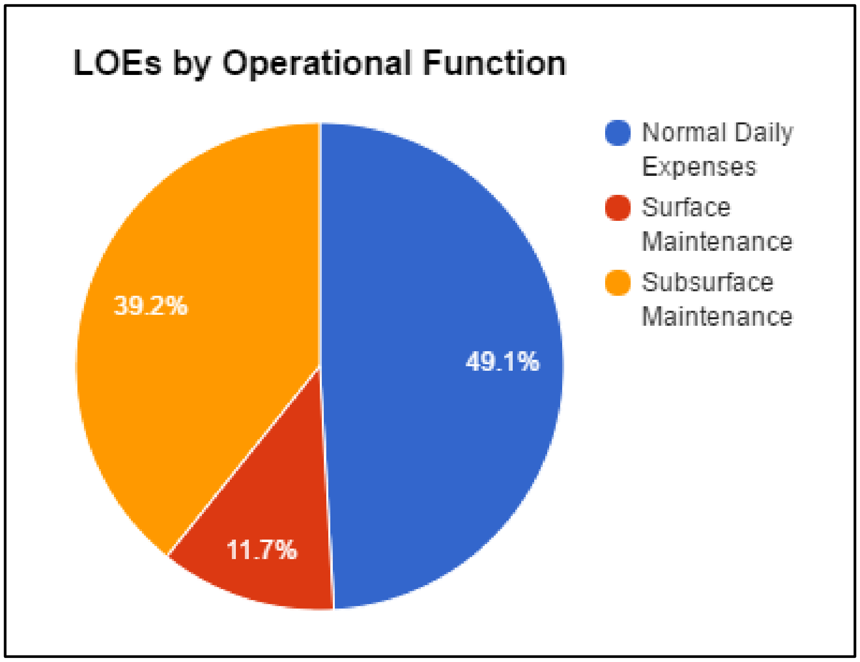
For starters, a company may choose to report a component of LOEs as a separate line item, or it may disclose the amount in a footnote. For example, companies will often report severance taxes as a separate line item, while lumping ad valorem taxes in with the rest of LOEs. The ad valorem component is then reported later in a footnote. In such cases, if we know the dynamics of the separately reported component, it is almost always a good idea to forecast that component separately.

Severance and ad valorem taxes, for instance, are determined by relatively stable (or otherwise knowable) tax rates. Consequently, future taxes can be reasonably forecasted by applying the historical tax rates to revenue forecasts. Other LOEs, such as COPAS-determined fees for non-operated properties are charged on a per-well basis using a relatively stable rate. In that case, a forecast of the non-operated well count can be used with the historical COPAS fees to reach a reasonable forecast for this LOE component.

Unfortunately, the bulk of LOE components will not be reported separately, leaving us with an amorphous bundle of expenses that needs to be projected. In that case, we first want to take an inventory of which components are remaining, which are likely to dominate, which can be deferred when cash flows are constrained, and how they will vary with factors such as production levels, oil and natural gas prices, etc.

Figures 3 shows data from a discontinued EIA series that recorded oil and gas lease equipment and operating costs from 1994 to 2009. For illustrative purposes, the figure uses the 2006-2009 averages for wells in the Rocky Mountain region producing from a depth of 8,000 feet.

Figure 3



As you can see from Figure 3, roughly half of the expenses are normal day-to-day operational activities, while the other half is entirely directed towards remedial and repair operations. This might sound like a high percentage for repairs ("Why not just make the wells right in the first place?"), but these maintenance expenses are more like getting an oil change or new tires for your car. For the most part, they are not unexpected. They are due to the simple wear and tear that the various parts endure.

The important point for our purposes is that these are expenses that (like getting an oil change or getting new tires) can be deferred for quite a while. And these expenses represent a very large portion of the total LOEs. These are expenses that can be cut immediately, though not indefinitely. It may be unwise in the long run, but if there is a temporary cash flow problem, this does remain an option to help ride out the storm. The current level of production will not drop off a cliff just these expenses are delayed. In some cases an individual well might stop production altogether (the equivalent of getting an unexpected flat tire), but this will not happen for an entire oil field all at once.

Figure 4

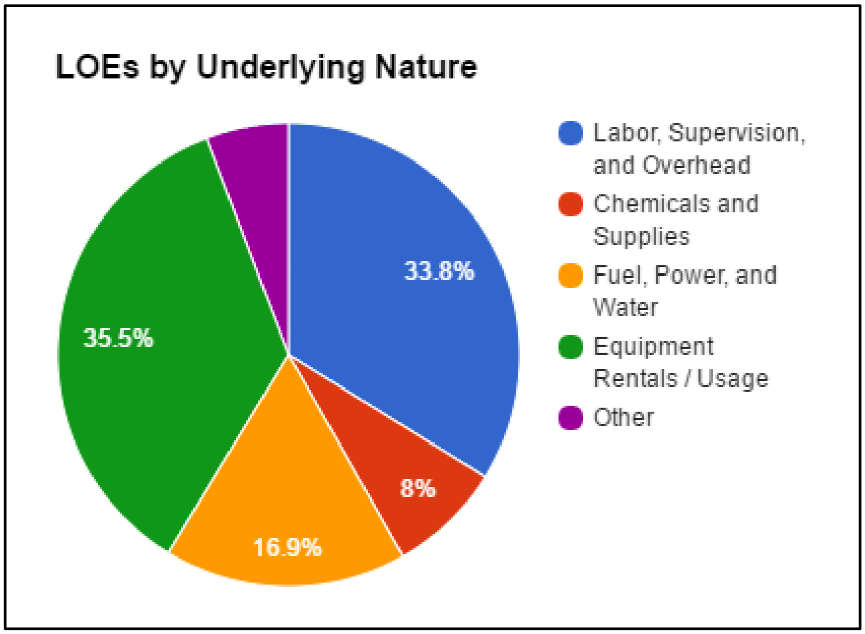


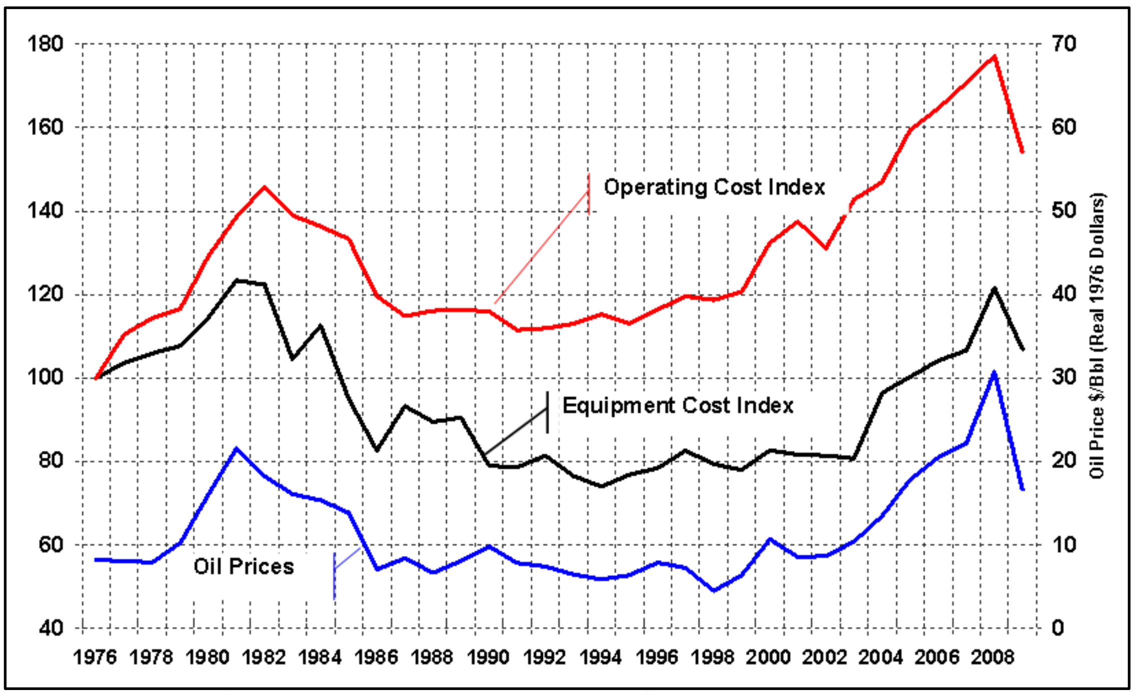
Figure 4 is based on the exact same data as Figure 3, however, this time it is separated based on the underlying nature of the goods and services purchased through the LOEs incurred. This helps us get a sense of what forces will be driving the overall level of LOEs. Over a third of the LOEs go to Labor, Supervision, and Overhead, meaning payments to oil and gas professionals. As such, these expenses will move in tandem with boom and bust cycles in the industry. Layoffs, pay cuts, reduced bonuses, and in some cases lower share-based compensation will all lower reported LOEs.

Equipment Rentals/Usage also makes up roughly a third of LOEs. These are expenses incurred for the services of large pieces of equipment, such as workover rigs, cement pumping trucks, and leased compressors. In other words, expenses tied to the costs of the large pieces of equipment used in the oil and gas industry. These will be affected by steel prices, the interest rates to finance these equipment purchases, supply and demand for their use, and the down-the-line labor that goes into their manufacturing. Since a given inventory of such equipment already exists at any moment in time, the rental rates will be sensitive to the inventory of existing equipment in the short-term and steel prices and other construction inputs in the longer term.

The third most important category in terms of the underlying nature of the expenses is Fuel, Power, and Water. While water might seem like it's out of place, the EIA most likely combined these items because they are all procured from utilities or utility-like entities with rate setting processes and procedures. This means these expenses will generally change very slowly with little, if any, volatility. The only exceptions to this are when natural gas is used as a fuel for oil field equipment or when water disposal (as opposed to water procurement) is a significant factor. Natural gas and water disposal are more driven by market-based pricing than regulated rates. As such, if they are significant for a particular operator, they should to be considered on a case-by-case basis. Water disposal may have challenges in Oklahoma that won't be present in New Mexico. Natural gas may be cheap in Pennsylvania but not in California.

Based on these three dominating inputs (professional compensation, equipment costs, and utility costs) it seems as though nearly all LOEs have at least some tendency to move in tandem with oil and gas prices. To get a sense of just how much them move (i.e. their sensitivity) with respect to oil and gas prices, we turn to Figure 5. This figure is derived from the same discontinued data set that was used in Figures 3 and 4. In this case, it shows EIA computed indices for operating and lease equipment costs for U.S. production in the lower 48 states, excluding production from the Gulf of Mexico.

Figure 5



Clearly, there is a strong correlation between oil prices and lease operating expenses. In fact, the correlation is so strong that it would be tempting to create a correlation-based formula to do all the LOE forecasting for us. However, as an index, the numbers have not only been corrected for inflation but they have also been corrected for the effects of declining production. In other words, these index numbers assume a set of wells that have flat production rates (that is, they never decline). This conceals the dynamics of fixed vs variable costs. It is especially important to keep this in mind when considering royalty trusts or E&P companies rapidly increasing production from freshly leased acreage. In such cases, the extent to which field and overhead expenses can be spread out across more barrels or Mcfs can have a big impact on the economics.

What Is One To Do?

What you need to do is get to a point where you have an intimate sense of how the LOEs move for the particular E&P company you are investigating. Go back through their history and see how LOEs have changed both on an LOE/boe basis and on a total LOE basis, and see what clues you can gather from both. Did the absolute level of LOEs stay flat while production fell? This would suggest high fixed costs or an unwillingness to cut semi-variable costs such as labor. If there was a sudden change in LOEs, what was the explanation? If it was caused by a change in electric utility rates, then this is likely a larger portion of the overall LOEs.

Make sure, in the end, that the quantitative story from the historical financials adds up with your qualitative understanding from the discussion and the general guidelines and perspectives from this article. Then, finally, use your understanding of these dynamics and interrelationships to project the LOEs for a variety of scenarios. If oil prices were to go higher, vendors would likely charge more, and the company would likely find it more worthwhile to spend heavily on their maintenance programs to squeeze every last barrel out of their existing wells. Thus, you should expect rising LOEs to wipe out some of the gains from higher prices. Unless, of course, higher oil prices mean they will be accelerating production, thus spreading more of their fixed costs across more barrels, lowering LOEs on a per BOE basis.

What if oil prices fall still further below their currently depressed prices? Will some wells become completely uneconomic and get shut-in, thus saddling the remaining wells with their share of the fixed LOEs? Or do the company’s worst wells eat up so much of the LOEs that the average LOEs/BOE across the company would actually be reduced by shutting them in, actually netting a larger profit for the company?

These questions can only be answered by looking in depth into each E&P company and having a sense of where in the economic spectrum their producing assets fall. Unfortunately, there is no short cut. However, the framework and examples in this article will save you time by helping you navigate as you go through the process. It is your map of the terrain. However, it is the particular E&P company you are analyzing that will determine where in that map you will find yourself.

Happy hunting!