

Can Efficient Wellbore Hydraulics Optimization Help Reduce CO₂ Emissions?

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Abstract

One of the common misunderstandings of hydraulics optimization is that in order to optimize or maximize hydraulics one must run pumps even faster and/or at higher pressures. When flow rates are at a maximum or pressures are at the rig equipment limits, why bother?

It turns out that in many cases, though flow rates and or pressures are at a maximum for the rig capability, the combination of pressure and flow rate is not optimized.

Proper optimization may result in lower flow rates, lower pressures or both. Depending on the results of the optimization, significant diesel fuel savings (or other prime mover energy source) will be realized, with a commensurate reduction in total emissions, including CO₂.

Without getting into the debate on CO₂ per se, these savings in diesel and emissions may be achieved without sacrificing ROP or hole cleaning, and do not typically have any negative side-effects or unintended consequences.

This advantage of optimum hydraulics will be explored in detail and examples given, so that field or office personnel can effectively manage hydraulics and reduce fuel consumption and emissions on their very next bit run!

Introduction

An extraordinarily important aspect of the successful drilling of a well—both in terms of economic efficiency and in terms of drilling trouble-free, is to have a robust and stable mud system that is circulated at a rate sufficient to clean rock cuttings and cavings out of the well. This mud and circulation system must at the very least:

- Remove freshly broken rock (or cuttings) from underneath the bit and move them to the annulus,
- Transport cuttings up the annulus to the surface where they can be removed from the mud system,

- Be reusable, at least during the life of the well if not multiple wells,
- Be of sufficient density to provide effective control of formation pressures,
- Have sufficient rheological properties so that it can be circulated without breaking down the wellbore,
- Be environmentally acceptable.

While great strides have been made in recent decades on both drilling fluid composition and modeling, there is still much to be learned and not all drilling operations have ready access to the best modeling available today.

Many wells are drilled with an excess of mud density or volumetric flow rate in order to ensure adequate formation pressure control and/or good hole cleaning.

This excess is not necessary and hence can be considered waste. This waste in turn offers a rich opportunity for savings in multiple categories.

Wellbore Hydraulics

Wellbore hydraulics has long been misunderstood and misapplied. Due to this lack of understanding, the mud viscosity or flowrates are often higher—sometimes much higher—than are necessary. In each case, the higher viscosity or volumetric flow rate costs additional energy to pump the mud.

Producing the Pressure and Flowrate

To produce the needed pressure and flow, a rig usually starts with the energy source as diesel fuel. (In some locations, natural gas might be used, and in fewer, direct connection to a power grid may be used.) The diesel fuel is used for diesel engine generator sets, where the chemical energy stored in the diesel is converted to mechanical motion (crankshaft output of the diesel engine) and then electricity from the usually attached generator.

The electricity is then routed through appropriate controls and wiring to electric motors (AC or DC), where the electric energy is converted back into mechanical motion (motor output shaft). The mechanical energy then powers the mechanical end of the mud pumps, which convert mechanical rotary motion to mechanical reciprocating motion via a more-or-less conventional crankshaft arrangement.

The reciprocating motion is applied to pistons in cylinders on the fluid ends of the pump, and with appropriate intake and outlet port check valves, the reciprocating motion compresses the drilling mud, converting the energy once again, this time by the compression of the mud (generating pressure). At this point, the high-pressure energy stored in the drilling fluid may be used or spent in a number of different ways and parts of the well flow system.

Important to note is that when the mud returns back to the mud pits after traversing through the drill string and back up the annulus, all of the energy (that started as stored chemical energy in the diesel) has been used up.

Use of the Pressure and Flowrate

Upon exit from the drilling rig mud pumps, the now-stored energy in the compressed drilling fluid will begin to be used up—either efficiently or not. In a broad sense, the energy will be used or spent in the following ways:

- Flowing through the surface piping to the standpipe
- Flowing up the standpipe and through the rotary hose and top drive
- Flowing down inside the drill pipe
- Flowing down the inside of the bottom hole assembly (BHA)
- Flowing through any parasitic equipment used in the drillstring, such as MWD tools, hole openers with nozzles, or mud motors
- Flowing through the bit nozzles themselves
- Flowing up the hole by BHA annulus
- Flowing up the hole by drill string annulus
- Flowing up the casing by drill string annulus
- Flowing up the marine riser by drill string annulus

Note that this is over-simplified, and there can be multiple sized annuli for most of the last four categories.

A standard traditional simple illustration of the pumping and wellbore mud circulation system is shown in Figure 2: Typical rig circulation system.¹

Of these drilling fluid energy “users”, most are entirely waste. The prime benefit of the pumped drilling fluid is in cleaning the bottom of the hole via the bit nozzle jets, powering downhole tools, and lifting cuttings up the annulus. The other transfers of mud from one point in the well to another are simply necessary, but not particularly productive in any way.

In some cases, such as the annuli pressure losses, the higher the losses the slower the drilling progress. The higher annular losses result in a higher equivalent circulating density (ECD) and hence higher differential pressure across the rockface and the bit and a resulting slower ROP.

Example Of Good Intentions Gone Wrong

As an example, assume a service company engineer has computed the optimum pressure and flow rate for an upcoming bit run (with other downhole tools accounted for). He or she selected a flow rate suitable for cleaning the hole and operating all tools that is 800 GPM, coincidentally approximately midway between the Q_{MINIMUM} and Q_{MAXIMUM} vertical red lines in Figure 3: Operational limits (red) and PCIRC (green) shown on Log-Log plot of Pressure vs. Flow rate.

(Digitally) running along the green line that plots all pressure drops in the fluid except the bit pressure drop, he finds that will use up about 2100 psi of the stored energy in the drilling fluid. Though the pumping system is rated at 6000 psi, the engineer has decided to use only 3900 psi, perhaps due to current pump liners. This still leaves 1800 psi available for bit nozzle pressure drops, or about 46% of what will be output from the pumps. He sizes the nozzles accordingly, and his computations result in choosing 7 #11 nozzles (0.6496 square inches TNFA).

All is well until someone in the organization—a rig site supervisor, a drilling engineer, or someone else—decides to override the service company engineer’s best judgment and substitute their own judgement, which in this case is to run 7 #16 nozzles (1.3744 square inches TNFA) instead of the #11’s.

The first thing about such a scenario is to note that the effect on TNFA by going from 11/32^{nds} to 16/32^{nds} is that the TNFA roughly doubles (exactly 2.116 times). Except for potentially resulting in a significant loss of ROP, this TNFA change by itself has little to no effect on the rest of the use of hydraulic energy, or pressure, provided that the pressure drop across the bit is sufficient to power downhole tools.

However, things get more interesting when one realizes that the equation for pressure loss through bit nozzles has the TNFA as a squared term in the denominator.

Bit nozzle pressure drop is given by

$$\Delta P_{\text{BIT}} = \frac{MW \times Q^2}{12775 \times \text{TNFA}^2} \quad \text{Eq. 1}$$

Note that for this version of the equation, a pressure recovery factor of around 15% has been assumed. Other primitive forms of the equation, not accounting for the pressure recovery factor,

were commonly expressed as

$$\Delta P_{BIT} = \frac{MW \times Q^2}{10868 \times TNFA^2} \quad Eq. 2$$

Modern PDC bits, or tri-cone bits with extended or mini-extended nozzles, may have a pressure drop between that of Equation 1 and Equation 2.

Since the TNFA has been approximately doubled, the pressure drop across the bit nozzles is divided by approximately four! (exactly 4.47!) In this example, rather than a planned bit pressure drop of around 1800 psi, the actual bit pressure drop at planned flow rate will reduce to less than 1/4 of that value, or 402 psi, as below.

$$\Delta P_{BIT-ACTUAL} = \Delta P_{BIT-PLANNED} \times \frac{TNFA_{PLANNED}^2}{TNFA_{ACTUAL}^2} \quad Eq. 3$$

Or

$$\Delta P_{BIT-ACTUAL} = \Delta P_{BIT-PLANNED} \times \left(\frac{TNFA_{PLANNED}}{TNFA_{ACTUAL}} \right)^2 \quad Eq. 4$$

$$\Delta P_{BIT-ACTUAL} = 1800 \times \left(\frac{.6496}{1.3744} \right)^2 = 402 \text{ psi}$$

When on bottom, instead of the planned maximum standpipe pressure of 3900 psi, the loss of pressure drop across the bit results in a standpipe pressure of about 2502 psi.

In this situation, the pumps would then commonly be run faster in order to bring up the standpipe pressure.

Since annular pressure loss increases exponentially with increased flow rate according to the proportional relationship:

$$P \sim Q^u \quad Eq. 3$$

(Note: the exponent u is also the slope of the wasted energy line in Figure 3: Operational limits (red) and PCIRC (green) shown on Log-Log plot of Pressure vs. Flow rate.)

The exponent u in equation 3 is commonly taken to be 1.8, though it can be easily adjusted based on well data for a more accurate relationship, and commonly ranges from 1.4 to 1.9. Note that the physics of the flow system restricts this exponent between 1.0 (fully laminar flow), and 2.0 (fully turbulent flow).

As pump rate is increased in our example, say to 1000 GPM, the wasted energy represented by the green line in figure 1 rises to around 3000 psi, (900 psi higher wasted energy than planned), leaving only about another 900 remaining for the bit without going higher than the planned 3900 psi—an improvement from the bit pressure drop at 800 GPM, but still

not design value and now with approximately 900 psi extra pressure loss on the annulus side.

This higher annular pressure loss translates to a higher ECD, and slower ROP if the well does not break down.

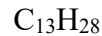
Though the pressure loss across the bit is lower, the hydraulic horsepower used will generally be greater than originally planned. With this increased power requirement will be increased prime mover requirements, ultimately leading backward in the pressure production train to a higher diesel fuel usage.

Adjustments to How Pressure and Flow rate are Utilized

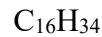
The useful parts of the drilling fluid energy may be adjusted, but the wasteful parts are wholly a function of fluid rheology, density, and flowrates. As such, optimizing the various “levers” available to the design engineer to maximize beneficial spending of energy while simultaneously reducing waste of energy – without sacrificing well drilling performance – is obviously desirable. More detail on how to accomplish this may be found in the author’s hydraulics book [1-Ramsey, (book) 2019], as well as the prior AADE paper by the author [2-Ramsey, (AADE) 2019].

CO₂ Production with Diesel Usage

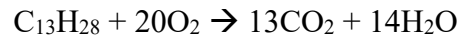
When diesel is burned, CO₂ is a product of combustion. While diesel contains a mixture of organic hydrocarbon molecules, typical and common ones are:



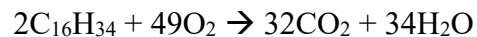
and



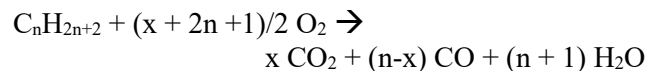
In perfect textbook combustion, oxygen combines with the hydrocarbon to yield heat energy, carbon dioxide, and water, as shown below:



or



Or more generically for imperfect combustion:



Though a relatively efficient fuel source, note that a product of combustion is CO₂. The commonly used amount of CO₂ produced is 22.3 lb_m of CO₂ per gallon of diesel, or 936.6 lb_m of CO₂ per barrel of diesel. Put another way, a ton of CO₂ is produced for every 90 gallons of diesel burned, or about 3.15 lb_m CO₂ for every lb_m diesel burned. (Note: In a similar reaction in air, nitrogen would also be involved but would not affect the C, H, O balance or take part in the reaction. Additionally, in air there would not be perfect combustion, so some carbon monoxide (CO) would also be produced.)

Example 1: Land Rig

In the previous example of good hydraulics planning gone wrong, the result in terms of carbon dioxide production is significant. A real-world example previously reported of a similar but not identical situation had an unoptimized diesel usage of about 2108 gallons per day. Due to the chemistry, even assuming perfect combustion (which of course is never achieved), this results in around 42147 pounds mass of carbon dioxide being produced daily. Partially optimizing the bit nozzles decreased this to around 33360 pounds mass CO₂ per day, and further optimization reduced it again to around 20739 pounds mass CO₂ per day—a savings of 21408 pounds or a little over 50%!

Referring to Figure 4: Carbon Dioxide Production for Running Diesel Prime Mover Powered Pumps, the estimate for CO₂ production for this land case is shown in the bar chart (left vertical axis), along with the diesel usage for the non-optimized, partially optimized, and fully optimized cases (right vertical axis.)

Example 2: Deepwater Floating Operation

In a deepwater example, after setting a 16" casing string, the daily drilling report showed the following:

MW in	=	13.1 ppG
MW out	=	13.1 ppG
Flow rate	=	988 gpm (downhole)
Flow rate	=	450 gpm (riser)
Standpipe	=	4610 psi
Bit TNFA	=	1.296 square inches
ECD	=	13.5 ppge

With this set of operating parameters, the bit pressure drop was computed to be 695 psi—only about 15% of the total system pressure loss, which is somewhat low. However, the previous FIT was only 14.7 ppge, hole cleaning Key Performance Indicators (KPIs) were adequate (though on the low side), and penetration rate was controlled (by geologic LWD considerations) and adequate.

With regard to CO₂ production, the higher flowrates and pressures (as compared to the first land rig example) resulted in a computed 46% increase in the diesel usage, and hence CO₂ production. Unless flowrates could be decreased without risking hole cleaning problems or downhole equipment malfunction, it might be difficult to further reduce hydraulic expenditures without hurting drilling KPIs.

In other cases, especially if geologic LWD requirements are not artificially constraining the rate of penetration, excessive pump rates have been reported. As the hydraulic horsepower required to deliver the drilling fluid at volume and pressure is

$$HHP = \frac{P \times Q}{1714} \quad \text{Eq. 5}$$

Increasing the operating pressure, say to 6000 psi or more, and flowing at 1200 GPM would increase the diesel usage by another 58% from the floating example above. It is likely that by properly optimizing hydraulics to effectively both clean the bit and clean the hole, that a significant amount of this increase could be saved.

Clearly, with advanced computer modeling taking the tedium out of hydraulic calculations, industry is doing an improved job of optimizing. Even still, optimizations can be usually improved with careful understanding of the problems, close attention to what the wellbore requires. As such, key performance indicators can be improved.

A second result in hydraulics optimization may be the reduced usage of diesel or other fuels to run the rig pumps, resulting in a corresponding significant decrease in carbon dioxide production.

Extrapolation

By extrapolation, assuming 2000 drilling rigs are in operating, that they experience an average 900 gallons per day of diesel savings—resulting in around 20,000 lbm/day savings in CO₂ production, and that they operate year-round, the savings is quite significant.

Each average rig would save 7.3 million pounds CO₂ production per year.

Worldwide this would be **14.6 billion pounds** of CO₂ production. In more common reporting terms, this translates to **6.622 million metric tons** of CO₂.

Referring to Figure 5: Current EPA estimated production and effect of 2.5% savings, the 2017 CO₂ production for petroleum and natural gas extraction and production industries is shown. The 17-year average is about 260 million metric tons. The golden area is the level by year, except for the potential savings, shown in, appropriately, green. Note the scale is exaggerated to show the effect of approximately 2.5% savings in this category of generation.

Four Questions

Though not the purpose of this paper, it should be noted that even a complete elimination of anthropogenic carbon dioxide may or may not be a desirable goal. In this author's opinion there are four relevant considerations to the global warming/climate change debate as relates to CO₂ in particular. None is stand-alone, and all must be clearly answered before a meaningful solution, if any is required, is designed and implemented.

1. Is our planet's climate significantly changing?
2. Is this change, if happening, the result of anthropogenic carbon dioxide, or is it due to alternative mechanisms?
3. Is this change, if happening and if anthropogenic, harmful?
4. If climate change is happening, if it is anthropogenic, and if it is harmful, then are any proposed solutions workable and are they the most efficient ways to deal with the issues?

Addressing the first, and not the second, third, and fourth questions, does a disservice or worse to humanity and our planet, especially given the stunning advances in civilization that are directly attributable to the use of low cost, abundant, and naturally biodegradable organic energy supplies.

Conclusions

- Tools are available to optimize the use of hydraulics for improved ROP and hole cleaning.
- Incorrect optimization can result in lower ROP.
- Correct optimization can result in less diesel being used to power the rig pumps, resulting in a significantly lower production of CO₂ without sacrifice of drill well performance.
- Other factors such as low pore pressure fracture pressure margins, requirements for hole cleaning can limit what can be achieved with hydraulics optimization.
- Control drilling, such as may be required for LWD tools, can limit what can be achieved with hydraulics optimization.

Acknowledgments

I would like to thank everyone who made this work possible over my career thus far, (far too numerous to mention individually, but especially members of the IADC Technical Publications committee), and all those who will help build on this and distribute it further. Additional details on these and other aspects of both hydraulics and hole cleaning may be found in the published book, *Practical Wellbore Hydraulics and Hole Cleaning*.²⁰ The author may be contacted at:

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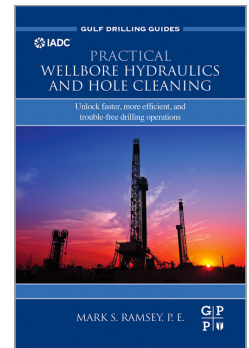


Figure 1

Nomenclature

<i>BHA</i>	=	<i>Bottom hole assembly</i>
<i>CCI</i>	=	<i>Cuttings Carrying Index or Carrying Capacity Index</i>
<i>CO</i>	=	<i>Carbon Monoxide</i>
<i>CO₂</i>	=	<i>Carbon Dioxide</i>
<i>PV</i>	=	<i>Plastic Viscosity, cP</i>
<i>ROP</i>	=	<i>Rate of Penetration, ft per hour</i>
<i>ECD</i>	=	<i>Equivalent Circulating Density, ppg</i>
<i>PWD</i>	=	<i>Pressure While Drilling</i>
ΔP_{bit}	=	<i>Pressure drop across the bit, psi</i>
$\Delta P_{bit\ opt}$	=	<i>Optimum pressure drop across the bit, psi</i>
<i>E_m</i>	=	<i>Mechanical Efficiency</i>
<i>E_v</i>	=	<i>Volumetric Efficiency</i>
<i>F</i>	=	<i>Force</i>
<i>GPM</i>	=	<i>Gallons Per Minute</i>
<i>HP</i>	=	<i>Horsepower</i>
<i>HHP</i>	=	<i>Hydraulic Horsepower</i>
<i>KPI</i>	=	<i>Key Performance Indicator</i>
<i>M</i>	=	<i>Mass</i>
<i>MW</i>	=	<i>Mud Weight, ppg</i>
<i>P_{bit}</i>	=	<i>Pressure drop across the bit</i>
<i>P_{circ}</i>	=	<i>Pressure drop through rig circulating system exclusive of the pressure drop through the bit</i>
<i>Power_{MAXIMUM}</i>	=	<i>-1 sloped rig power limitation line on a log log plot of pressure vs flowrate</i>
<i>Psi</i>	=	<i>pounds per square inch</i>
<i>P_{max}</i>	=	<i>P_{MAXIMUM}, Maximum surface pressure available on a rig</i>
<i>PPG</i>	=	<i>Pounds Per Gallon</i>
<i>ppg</i>	=	<i>Pounds Per Gallon</i>
<i>PPGE</i>	=	<i>Pounds Per Gallon Equivalent</i>
<i>P_{surf opt}</i>	=	<i>Standpipe pressure at the surface under optimum conditions</i>
<i>Q</i>	=	<i>Flow rate</i>
<i>Q_{crit}</i>	=	<i>Flow rate where the two operating limits of maximum pressure and maximum available hydraulic power intersect</i>
<i>Q_{opt}</i>	=	<i>Optimum flow rate for optimized hydraulics across the bit</i>
ρ	=	<i>Rho - density</i>
<i>t</i>	=	<i>Time</i>
<i>TFA</i>	=	<i>Total Flow Area, square inches (Interchangeable with TNFA)</i>
<i>TNFA</i>	=	<i>Total Nozzle Flow Area, square inches (Interchangeable with TFA)</i>
<i>u</i>	=	<i>“Unknown” exponent of flow rate in the power law equation, and, slope of best fit line on logarithmic paper when plotting pressure vs. flow rate</i>
<i>v</i>	=	<i>Velocity</i>
<i>V_C</i>	=	<i>Velocity of cuttings, fpm</i>
<i>V_A</i>	=	<i>Velocity of bulk drilling fluid, fpm</i>

Important Equations

Bit nozzle pressure drop is given by

$$\Delta P_{BIT} = \frac{MW \times Q^2}{12775 \times TNFA^2} \quad Eq. 6$$

Total Nozzle Flow Area, TNFA:

$$TNFA = \sqrt{\frac{MW \times Q^2}{12775 \times \Delta P_{BIT}}} \quad Eq. 4$$

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Table 1: Properties of Selected Fuels

Fuel	Liquid density	Specific carbon content	Specific Energy content		Specific CO ₂ emission (amount of fuel basis)		
	kg/l	kg _c /kg _{fuel}	kWh/kg _{fuel}	Btu/lb _{fuel}	KgCO ₂ /kg _{fuel}	KgCO ₂ /gal _{fuel}	lbCO ₂ /gal _{fuel}
Methane (natural gas)		0.75	15.4	23900	2.75		
Propane	0.51	0.82	13.8	21300	2.99	5.78	12.7
Butane	0.564	0.83	13.6	21100	3.03	6.47	14.3
Gasoline	0.737	0.9	12.9	19900	3.3	9.2	20.3
Kerosene (Jet)	0.821	0.82	12	18500	3	9.33	20.6
Diesel	0.846	0.86	12.7	19605	3.15	10.1	22.3

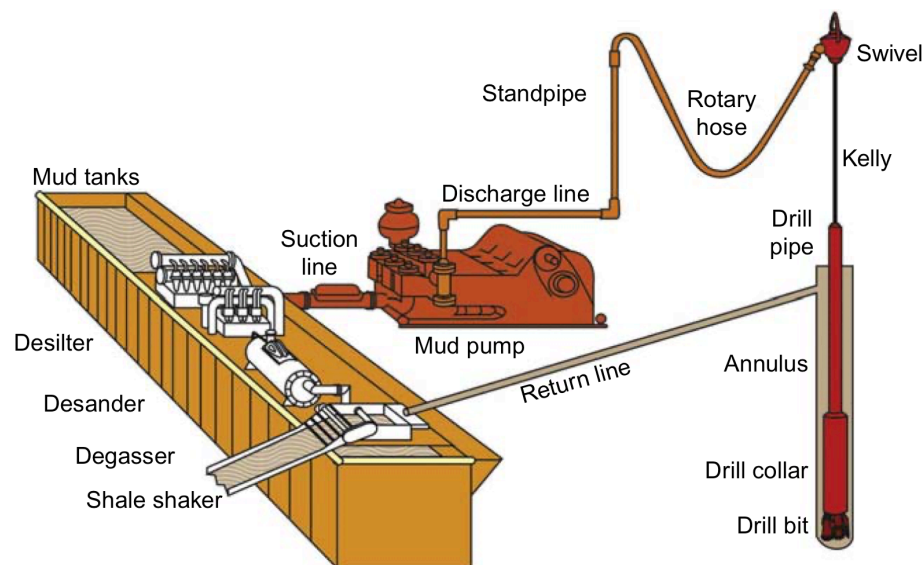


Figure 2: Typical rig circulation system

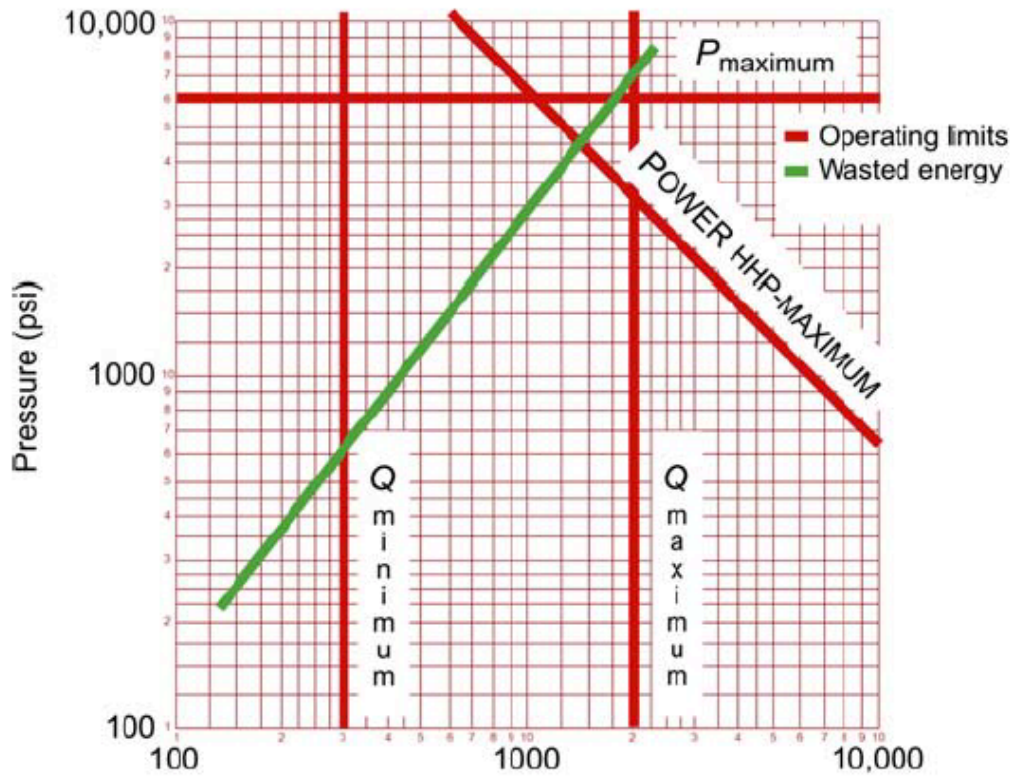


Figure 3: Operational limits (red) and PCIRC (green) shown on Log-Log plot of Pressure vs. Flow rate

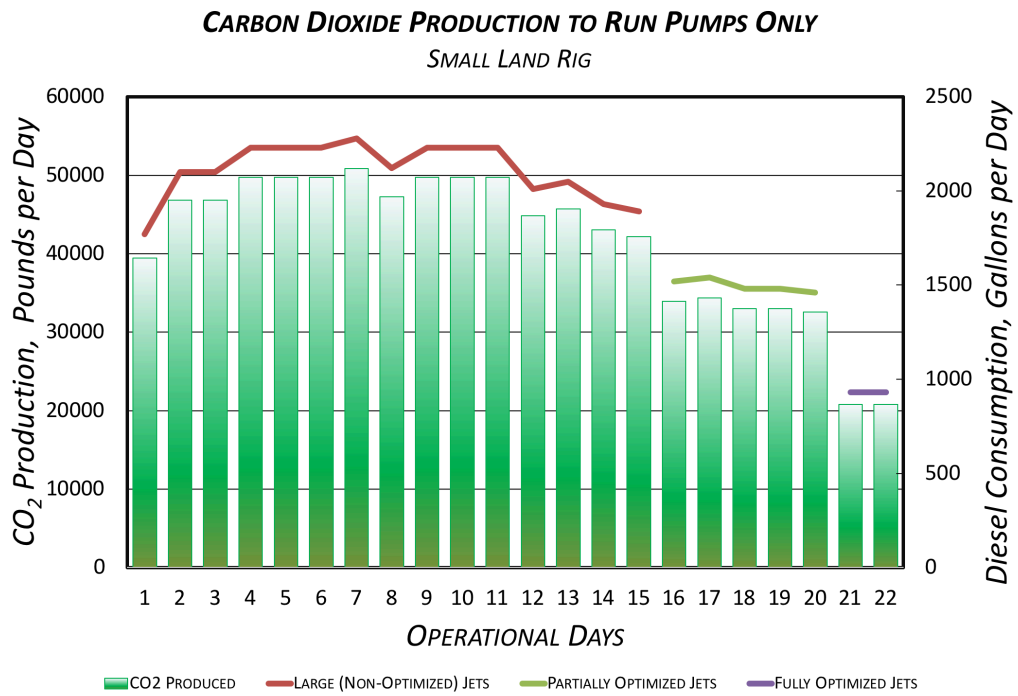


Figure 4: Carbon Dioxide Production for Running Diesel Prime Mover Powered Pumps

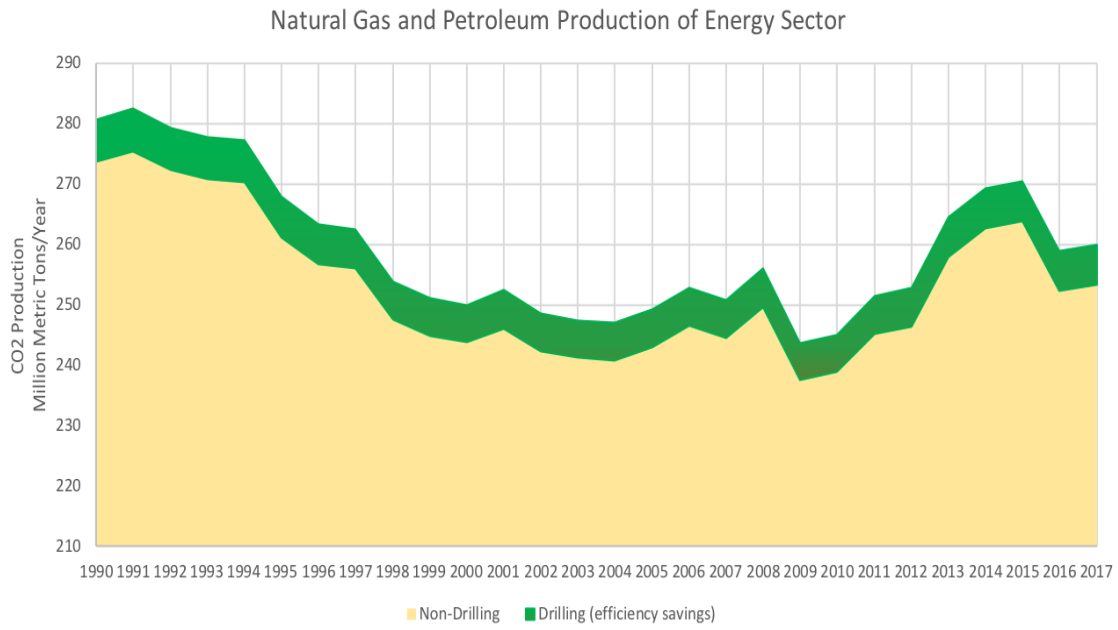


Figure 5: Current EPA estimated production and effect of 2.5% savings (note vertical scale is offset for emphasis)

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