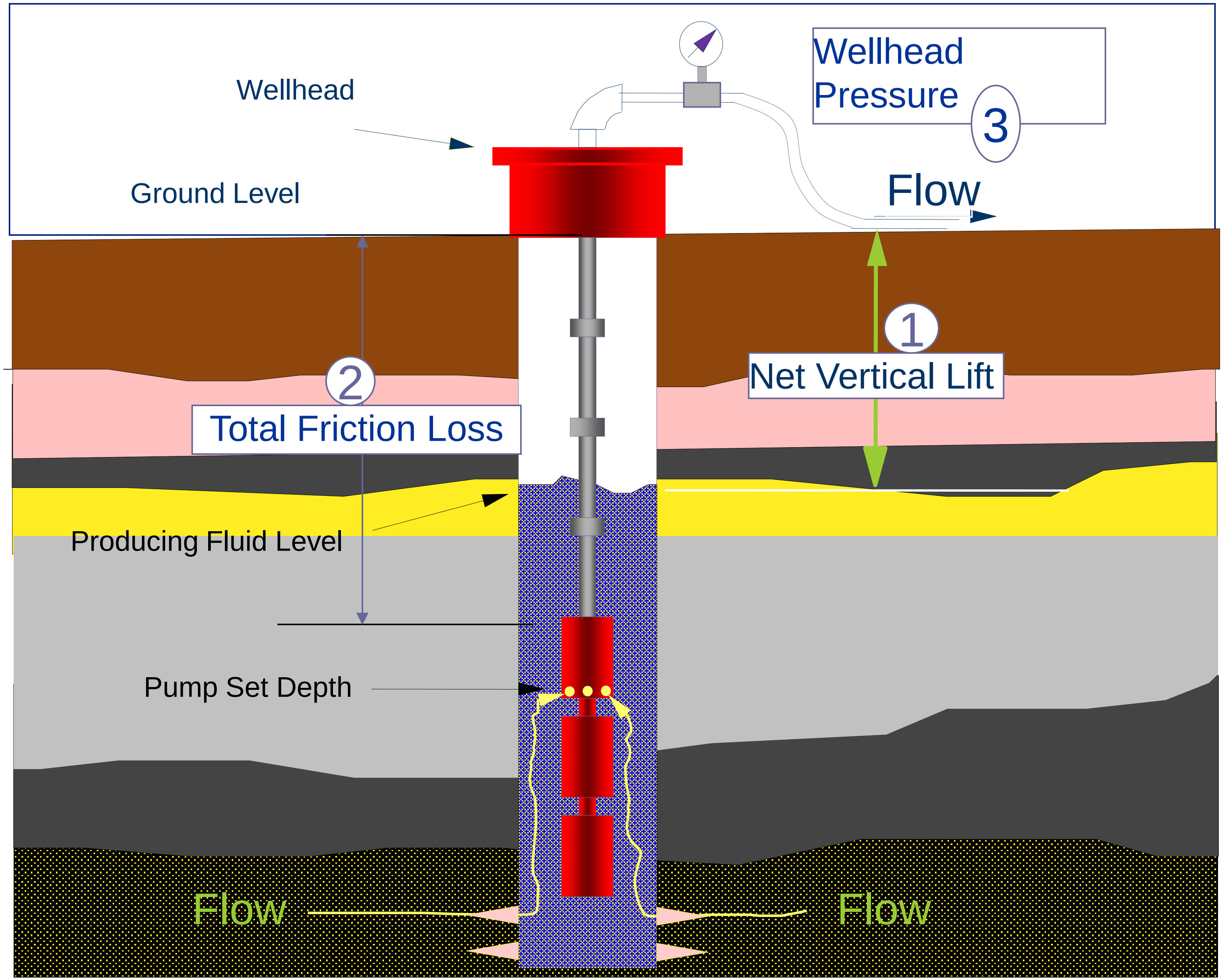
Total Dynamic Head and Pump Sizing

Components of the TDH



Total Dynamic Head

”Net vertical lift” is the vertical distance through which the fluid must be lifted to get to the surface.

The energy required to lift the fluid can be determined by the equation:

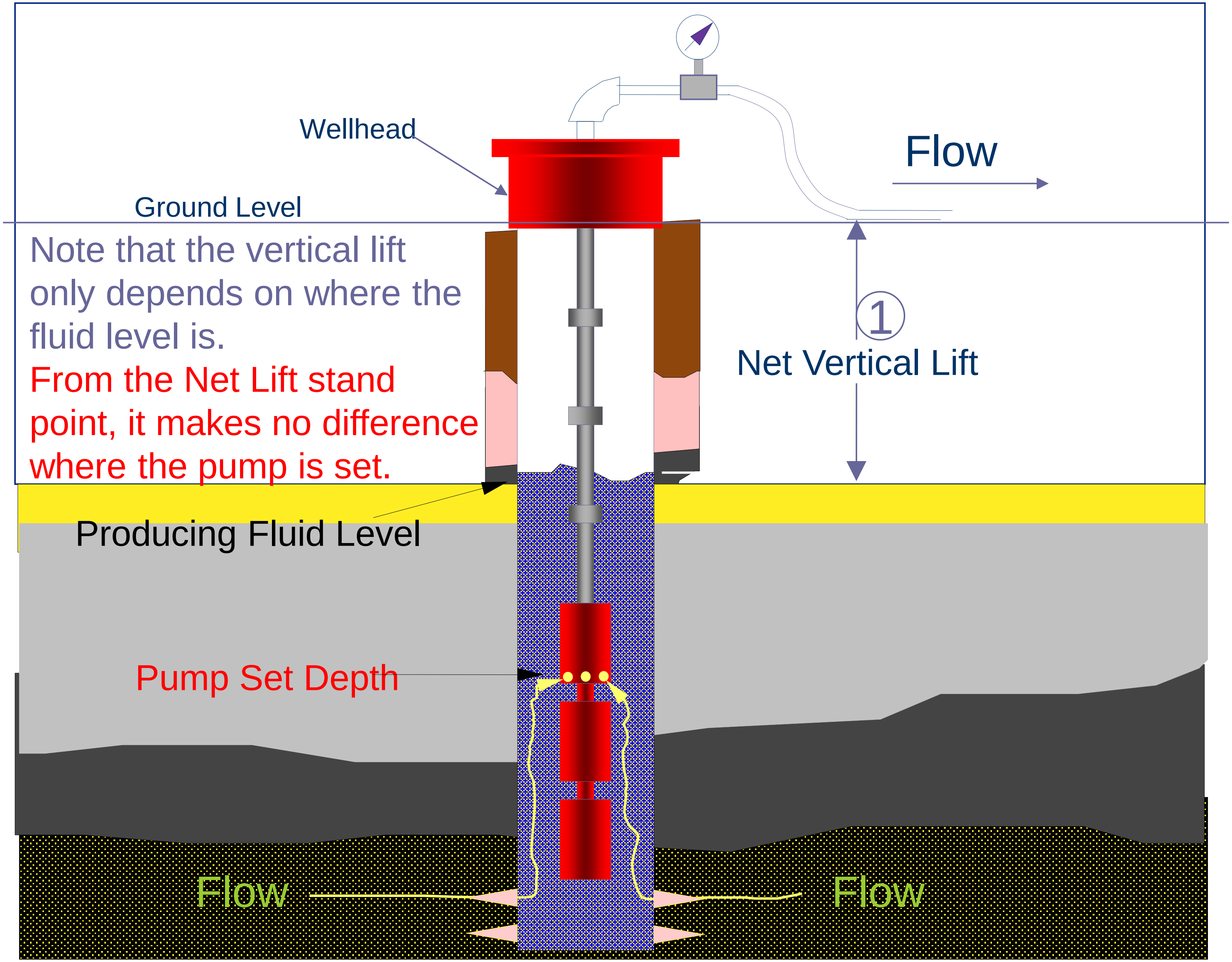
$$\text{Work (energy)} = mg\Delta h$$

Where: m is the mass of the fluid,

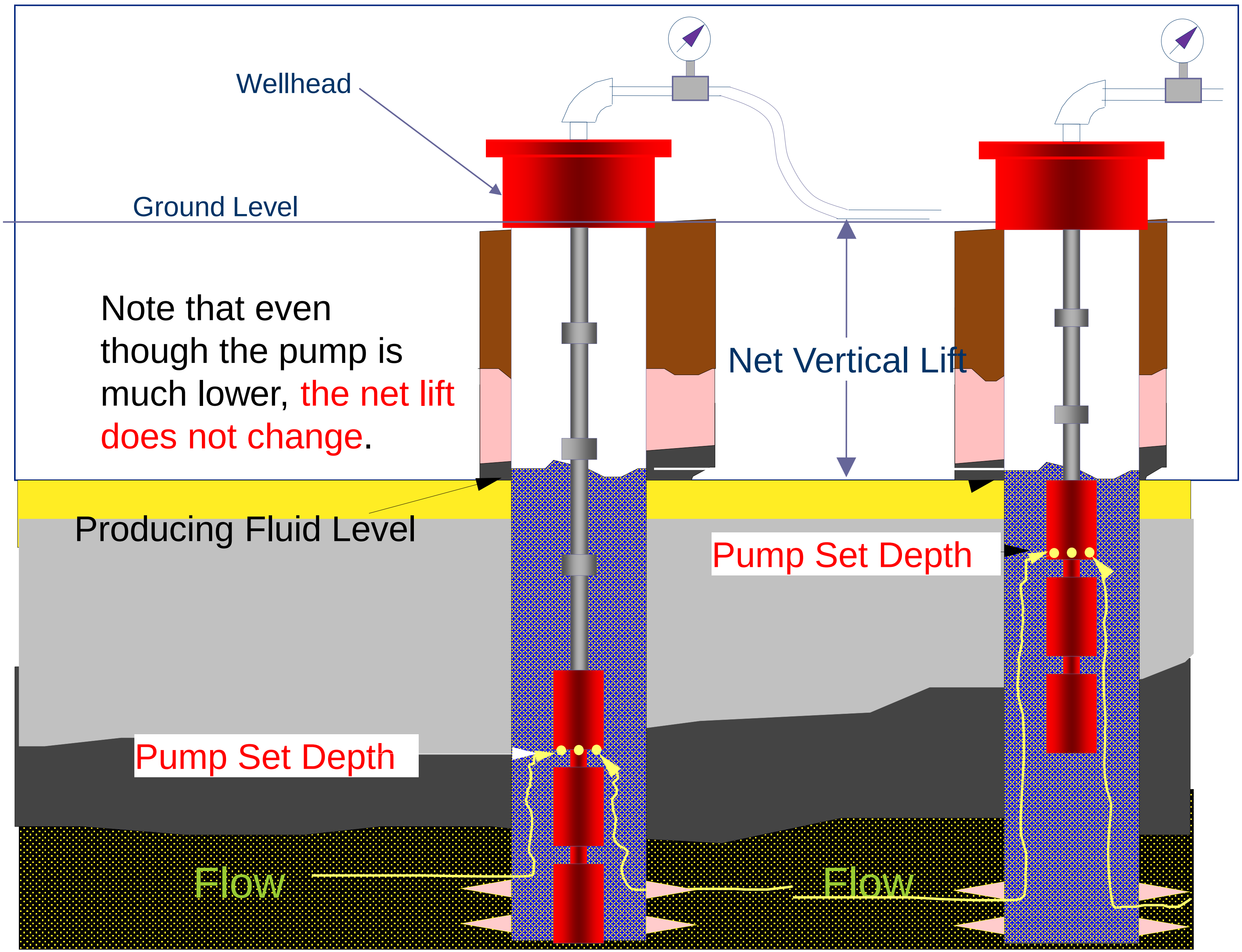
g is the acceleration due to gravity, and

Δh is the height the fluid is lifted.

Net Vertical Lift

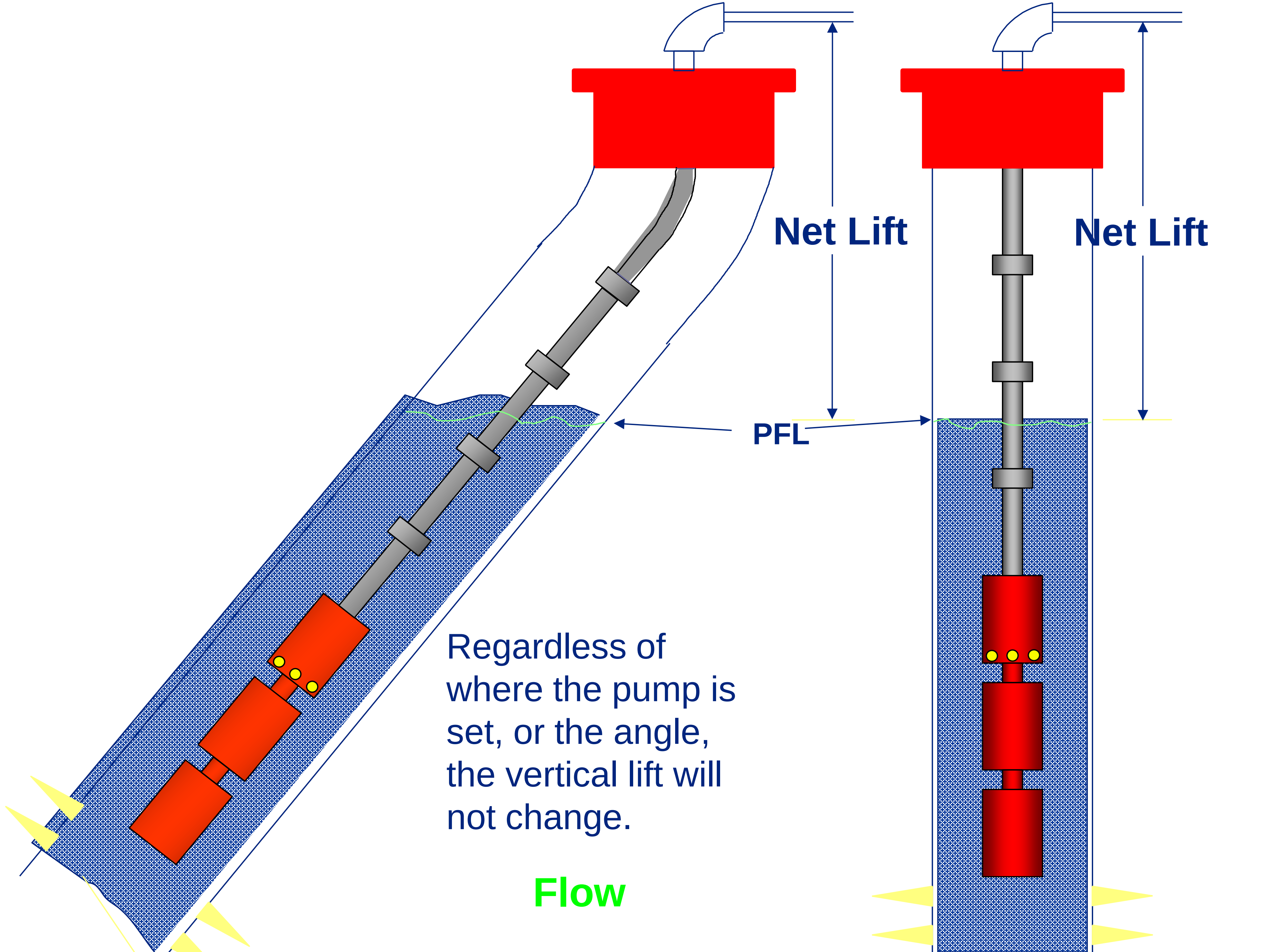


Net Vertical Lift



Determining Pump Setting Depth

Producing Fluid Level – Now and future
Gas – free, quantity
Angle and DLS
Casing Size
Stress Analysis
Temperature



Regardless of where the pump is set, or the angle, the vertical lift will not change.

Total Dynamic Head - Net Vertical Lift (1)

For the purposes of this example, we will assume we are given a fluid level of 4000 feet from surface (vertical distance).

1

Net Vertical Lift = 4000 ft

Remember if the well is deviated, the total measured distance from surface could be much greater but, since the work done in moving the fluid sideways is zero, only the vertical distance matters.

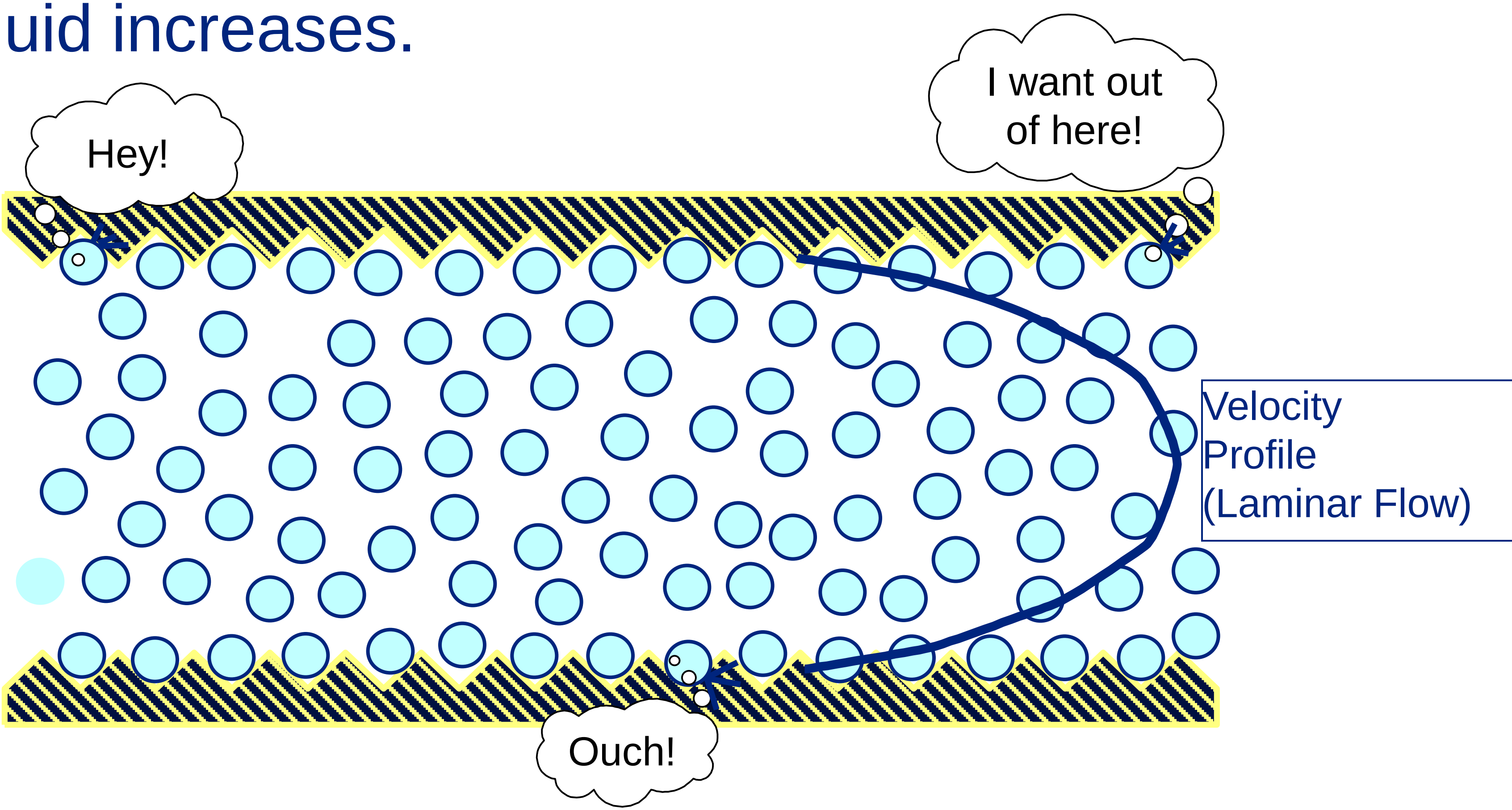
Total Dynamic Head - Friction Loss (2)

Friction is an energy loss (we actually measure it as a pressure loss) due to viscous shear of the flowing fluid.

In a fluid, molecules are free to move past each other but there may be a little resistance. This resistance is due to shear forces which must be overcome.

Total Dynamic Head - Friction Loss (2)

The walls of the pipe, however, will tend to "stick" to the fluid so shear forces between the pipe and the fluid can be quite large and increase as the velocity of the fluid increases.



Total Dynamic Head - Friction Loss (2)

The amount of friction present can be represented by a "friction factor" - *f* . *Given "f" we can calculate the pressure loss from the following:*

$$\Delta P = \frac{f \rho v^2}{2 g_c d}$$

Where ***ΔP = pressure loss***

ρ = fluid density

v = fluid velocity

gc = gravity constant

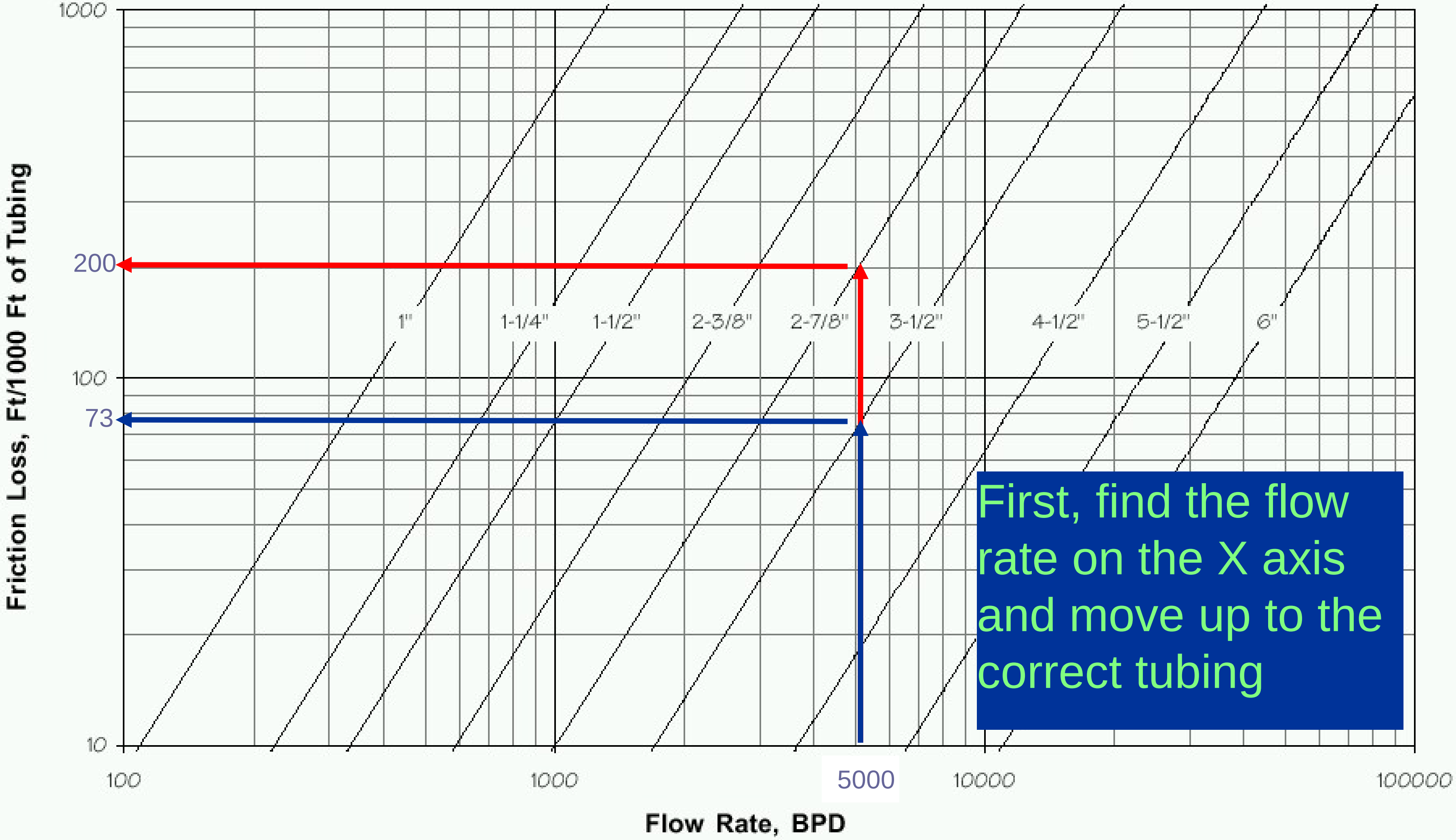
d = pipe diameter

Total Dynamic Head - Friction Losses (2)

When Calculating Friction Loss by hand a chart is generally used

Say, for example, we have a total tubing length of 6500 feet and we want to produce 5000 bpd. We have both 2 7/8" tubing and 3.5" tubing in stock. What will the friction be?

Friction Loss



Based on Hazen Williams Formula:

$$F = 2.083(100/C)^{1.85}(Q/34.3)^{1.85}/ID^{4.8655}$$

Where: F = Ft Loss / 1000 Ft

Q = BPD

C = 120

Table 2C- Friction Loss in A.P. I. Tubulars

Total Dynamic Head - Friction Losses (2)

Since we have 6500' of tubing:

For 2 7/8", Friction = 200*6.5 = 1300 feet of loss 2

For 3 1/2", Friction = 73*6.5 = 475 feet of loss

If we can use 3 1/2" tubing, this will allow us to use a smaller pump and motor which will reduce cost.

Let's assume we can't get 3 1/2" tubing

Total Dynamic Head - Friction Losses (2)

Is bigger tubing always better?

No

…potential problems due to solids in suspension (sand).

Unfortunately the best teacher here is experience.

Total Dynamic Head - Wellhead Pressure (3)

Up to this point, we have been calculating everything in terms of "feet". This is very convenient when sizing a pump.

WHY?

Total Dynamic Head - Wellhead Pressure (3)

For example, given:

Well head pressure	=	200 psi
Water Cut (1.07 sp. Gr.)	=	60%
API of Oil		30

Total Dynamic Head - Wellhead Pressure (3)

This is the equation to convert from psi to feet but we still need to know the specific gravity.

$$\text{Wellhead "Feet"} = \frac{\text{Wellhead Pressure}}{0.433 \times \text{sp.gr.}}$$

Total Dynamic Head - Wellhead Pressure (3)

Petroleum Engineers prefer to use the API gravity because it is a larger number and easier to "get a feel for". The equations for converting from one unit to the other are:

$$Sp.Gr. = \frac{141.5}{131.5 + API}$$

$$API = \frac{141.5}{Sp.Gr.} - 131.5$$

Total Dynamic Head - Wellhead Pressure (3)

For our example, use an oil with an API gravity of 30. This means that we are assuming the oil specific gravity is 0.876.

$$Sp.Gr. = \frac{141.5}{131.5 + 30} = 0.876$$

Total Dynamic Head - Wellhead Pressure (3)

$$Sp.\,Gr. = (f_w \times \gamma_w) + (f_o \times \gamma_o)$$

Where :

f_w is the water fraction

γ_w is the water specific gravity

f_o is the oil fraction

γ_o is the oil specific gravity

Total Dynamic Head - Wellhead Pressure (3)

For our example, the “composite” specific gravity is 0.992

$$\text{Sp. Gr.} = (f_w \times \gamma_w) + (f_o \times \gamma_o)$$

$$\text{Sp. Gr.} = (0.60 \times 1.07) + (0.40 \times 0.876) = 0.992$$

Total Dynamic Head - Wellhead Pressure (3)

Using the numbers in our example:

$$\text{Wellhead "Feet"} = \frac{200\ \text{psi}}{0.433\ \text{psi/ft} \times 0.992} = 465\ \text{ft}$$

3

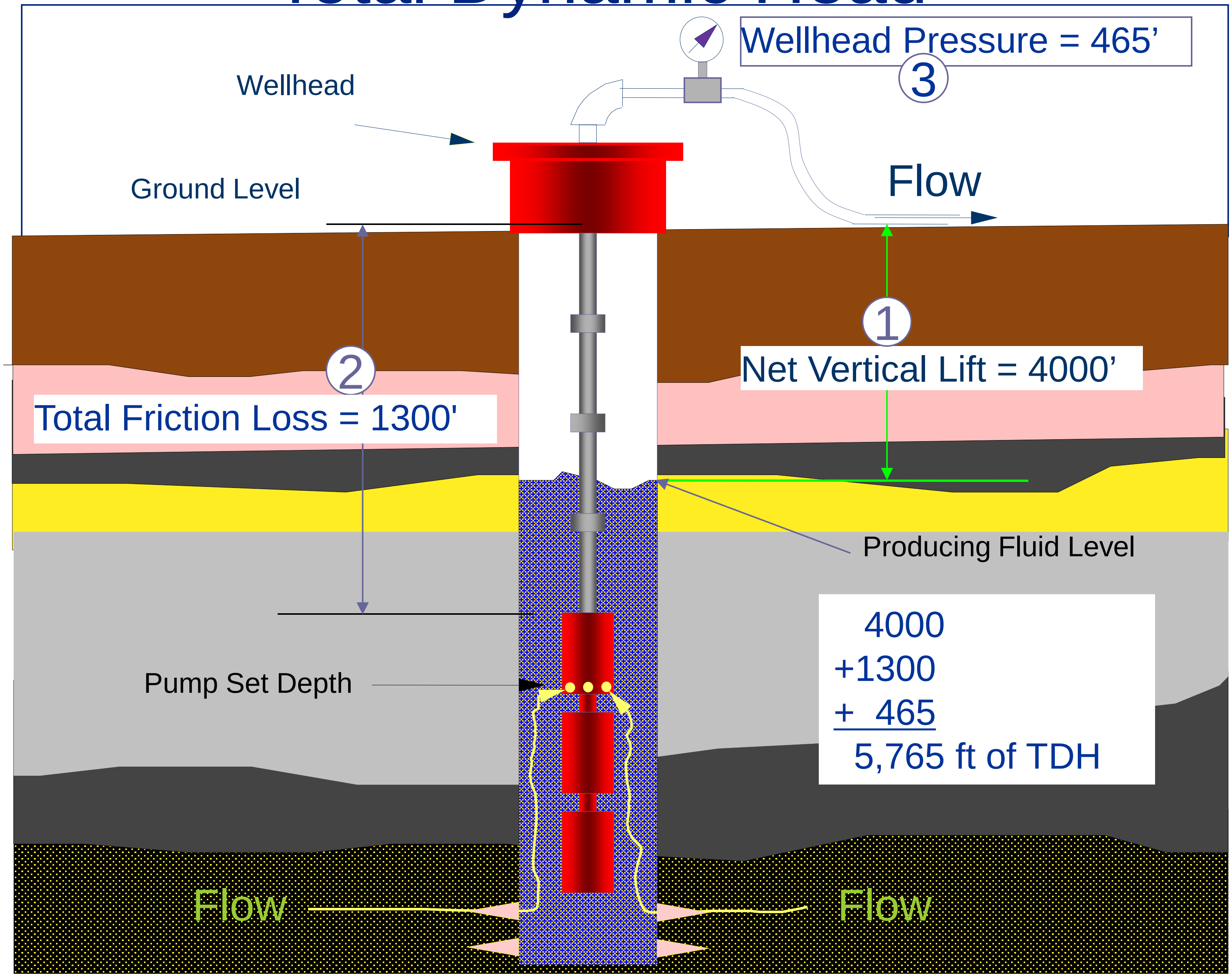
Total Dynamic Head

The TDH will be the sum of:

Net Lift,
Friction Loss, and
Wellhead pressure.

We will assume 2 7/8" tubing since it was in inventory:

Total Dynamic Head



Total Dynamic Head

So we would need to design a pump with enough stages to produce 5765 feet of head.

What happens if the “composite” specific gravity was lower than we calculated?
(i.e. 0.82 instead of 0.992)

Total Dynamic Head

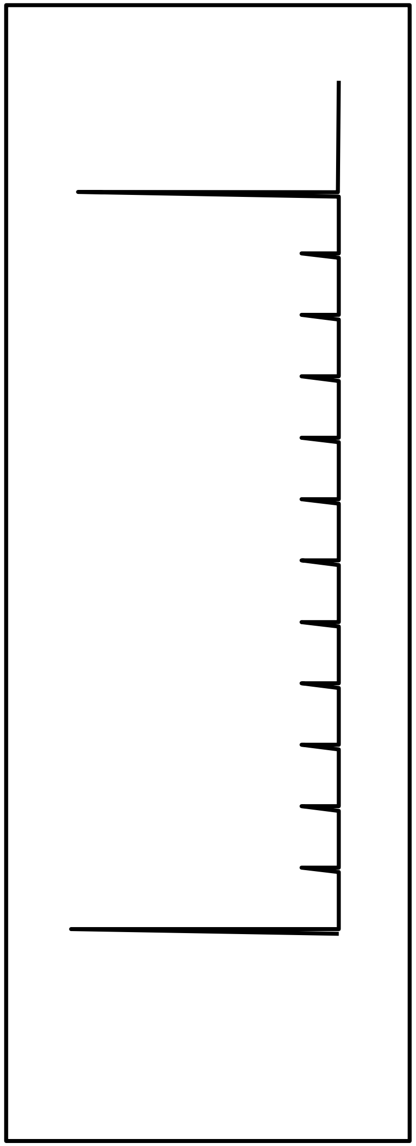
If this were the case, the wellhead "feet" would have been 563 feet instead of 465 which means we were 92 feet short in our calculations.

The pump’s rate would therefore be less than expected.

We would need a pump to deliver 5857 feet of TDH rather than one for 5765 feet.

Total Dynamic Head - determining fluid level

A word of caution when using fluid levels from "Sonic Logs" to determine net lift...
Sonic Logs estimate the fluid level by making a loud noise in the annulus (usually a compressed air) and measuring the amount of time it takes for the sound wave to reflect back to the wellhead after it hits the fluid level.



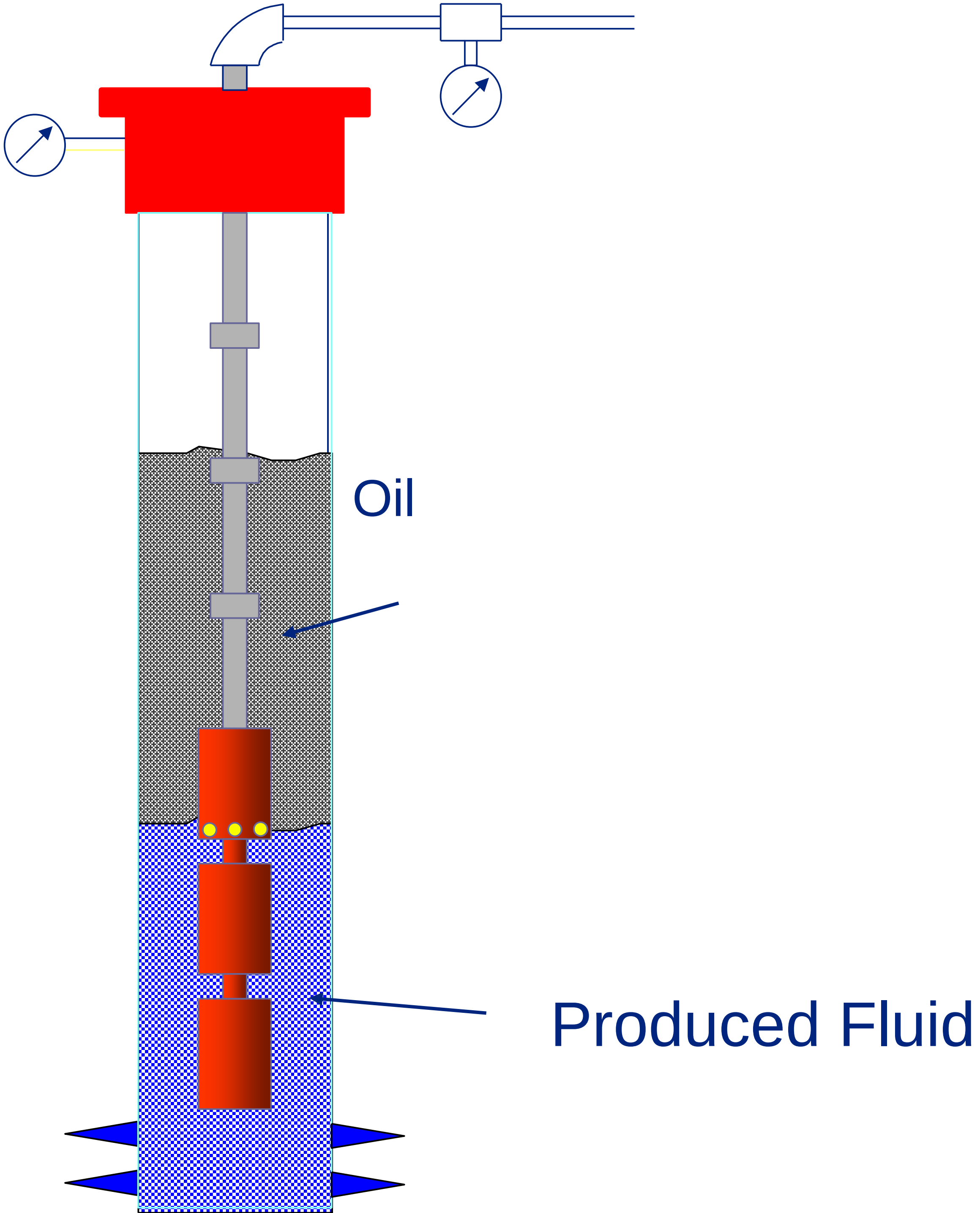
Total Dynamic Head

The Sonic level determination only looks at <u>where the fluid level is and not what the fluid is.</u>

There will be significant variations for:

Gassy wells (foam not solid fluid)

High water cut wells


Oil
Produced Fluid

Total Dynamic Head

Example:

Top of Perforations =	8,000 ft
Pump Setting Depth =	6,500 ft
Fluid Level (Sonic) =	4,000 ft
Water Cut = 60%	
Spec. Grav. (Water) =	1.07
Oil API Gravity =	30

What is the Pwf and PIP?

Total Dynamic Head

The crude oil specific gravity is 0.876 and the fluid composite gravity is 0.992.

$$Oil\ Sp.Gr. = \frac{141.5}{131.5 + 30} = 0.876$$

$$Sp.Gr. = 0.60 \times 1.07 + 0.40 \times 0.876$$

$$= 0.992$$

Total Dynamic Head

For the portion above the intake, we assume due to natural separation, that the fluid is all oil with a specific gravity of 0.876 and this is a reasonable assumption.

$$\begin{aligned} PIP &= (6500 - 4000)\text{ft} \times 0.433 \text{ psi/ft} \times 0.876 \\ &= 948 \text{ psi} \end{aligned}$$

Total Dynamic Head

For the portion below the intake, we assume that the fluid is the same as produced from the well. That is to say that it is 60% water and the average specific gravity is 0.992.

$$\Delta P = (8000 - 6500)\ \text{ft} \times 0.433\ \text{psi/ft} \times 0.992$$
$$= 644\ \text{psi}$$

Total Dynamic Head

The perforation pressure will be the sum of the pressure at the pump intake (PIP) and the pressure differential between the pump setting depth and the perforation depth.

$$P_{perfs} = 948 + 644 = 1592 \text{ psi}$$

Total Dynamic Head

If we had assumed that the total fluid column in the well were a crude/water mixture,

$$P_{perfs} = (8000 - 4000)\text{ ft} \times 0.433\text{ psi/ft} \times 0.992$$
$$= 1720\text{ psi}$$

we would have calculated a perforation pressure of 1,720 psi instead of 1,592 psi.

Total Dynamic Head

Assuming a static reservoir pressure of 2800 psi and a production rate of 5000 BPD, the resultant error in PI calculation would have been:

Correct = 5000 BPD / (2800 psi – 1592 psi)
= 4.14 BPD/psi

Incorrect = 5000 BPD / (2800 psi – 1720 psi)
= 4.63 BPD/psi

12% Error

5000 bpd Pump Sizing

We have the TDH of 5765’,

To Size the Pump we will assume 7“ 23# casing

The design rate is 5000 BPD.

60 Hz power available.

Pump Applications

Immediately above the pump curve is a technical data section. This section is very useful as it contains almost every piece of information necessary to make certain a pump is suitable for an application.

The left column shows the recommended operating range and physical parameters of the pump, such as diameter and shaft size.

The right column shows important physical limitations of the pump itself such as shaft horsepower and housing burst pressure limits.

The series designations are defined as:

Type	Series	Outside Diameter	Minimum Casing Size
A	338	3.38”	4 ½”
D	400	4.00”	5 ½”
G	540	5.13”	6 5/8”
S	538	5.38”	7”
H	562	5.63”	7”
J	675	6.75”	8 5/8”
L	738	7.25”	9 5/8”
M	862	8.63”	10 ¾”
N	950	9.5”	11 ¾”
	950	10.00”	11 ¾”
P	1125	11.25”	13 3/8”

5000 bpd Pump Sizing

We must review the curves in the catalog within the desired flow rate.

A review of what pumps are available that will produce 5000 bpd. For 60 Hz power, we will use the 3500 RPM curves.

Note: If the power were 50 Hz, we would use the 2917 RPM curves.

Bigger Diameter is almost always better:

Advantages:

Usually More Efficient

Usually Less Expensive (less stages/pumps)

Better in Gas & Viscosity

Handles Higher HP

Disadvantages:

- Lower Maximum Pressure
- Can Interfere w/ Y-Tool
- Often more Downthrust

Various Pumps

Let’s find pumps that will produce 5000 bpd in 7” casing

Possible options arethe DN5800, GN5600, GN5200 and SN5000

NOTE: Do not be confused by B.E.P or the Best Efficiency Point. You will rarely design a pump at B.E.P.

Find 5000 bpd and see where it intersects the Head Curve this will be the lift per stage at 5000 bpd

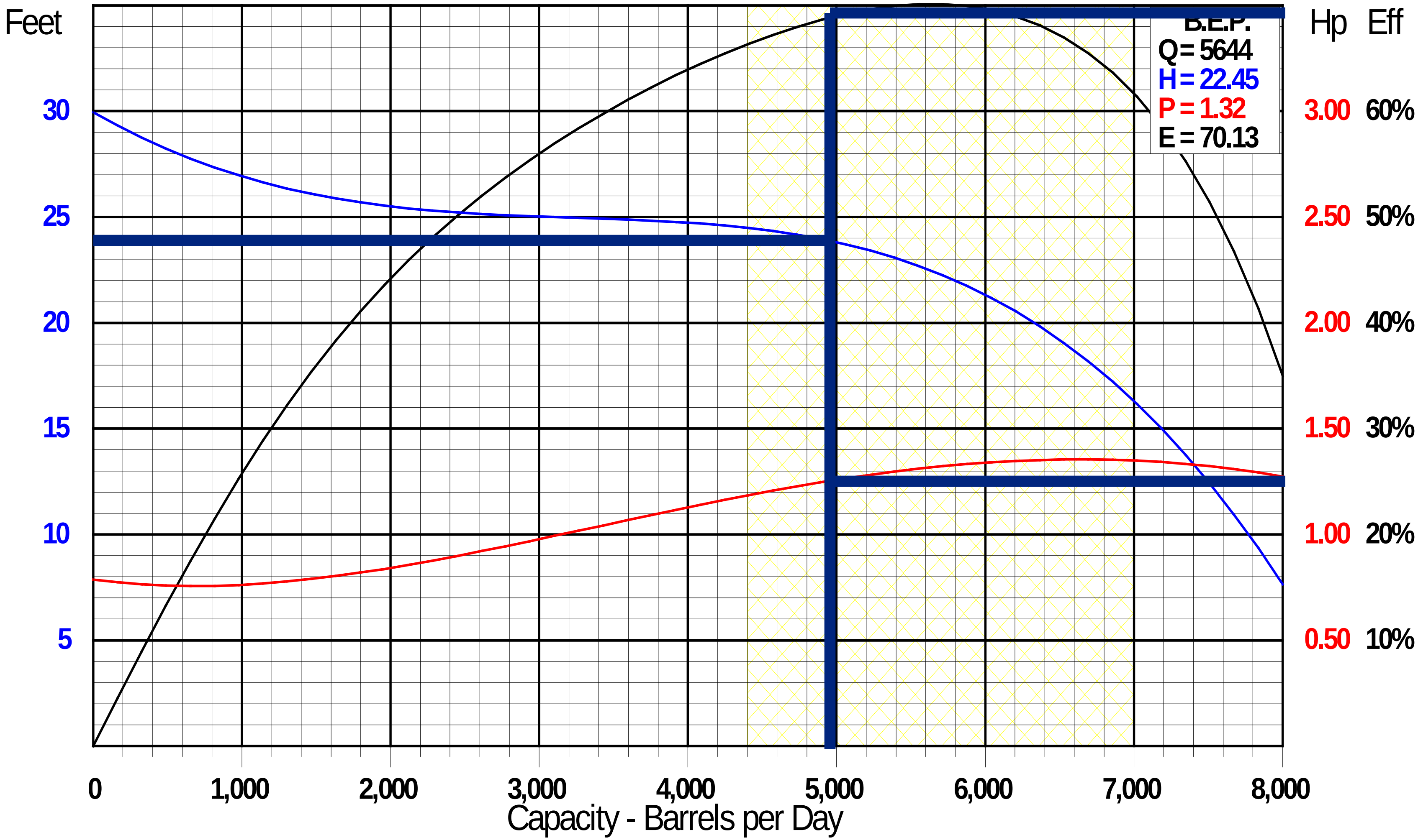
REDA Production Systems

Reda Pump Performance Curve
D5800N
400 Series - 1 Stage(s) - 3500 RPM - 60 Hz

Rev. -

Minimum Casing Size 5.500 OD Check Clearances

Fluid Specific Gravity 0.99



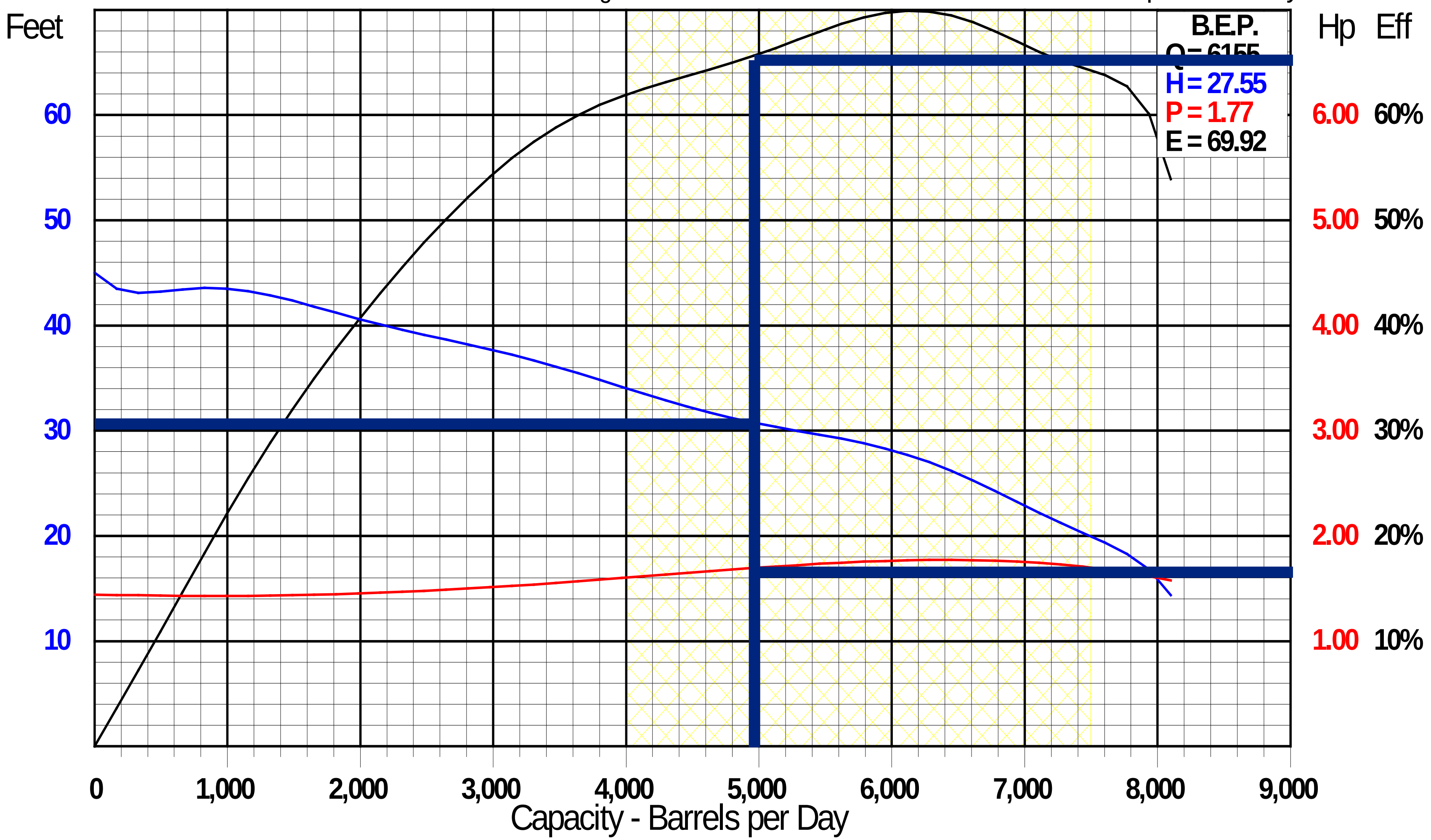
REDA Production Systems

Reda Pump Performance Curve
GN5600
540 Series - 1 Stage(s) - 3500 RPM - 60 Hz

Rev. A

Minimum Casing Size 6.625OD Check Clearances

Fluid Specific Gravity 0.99



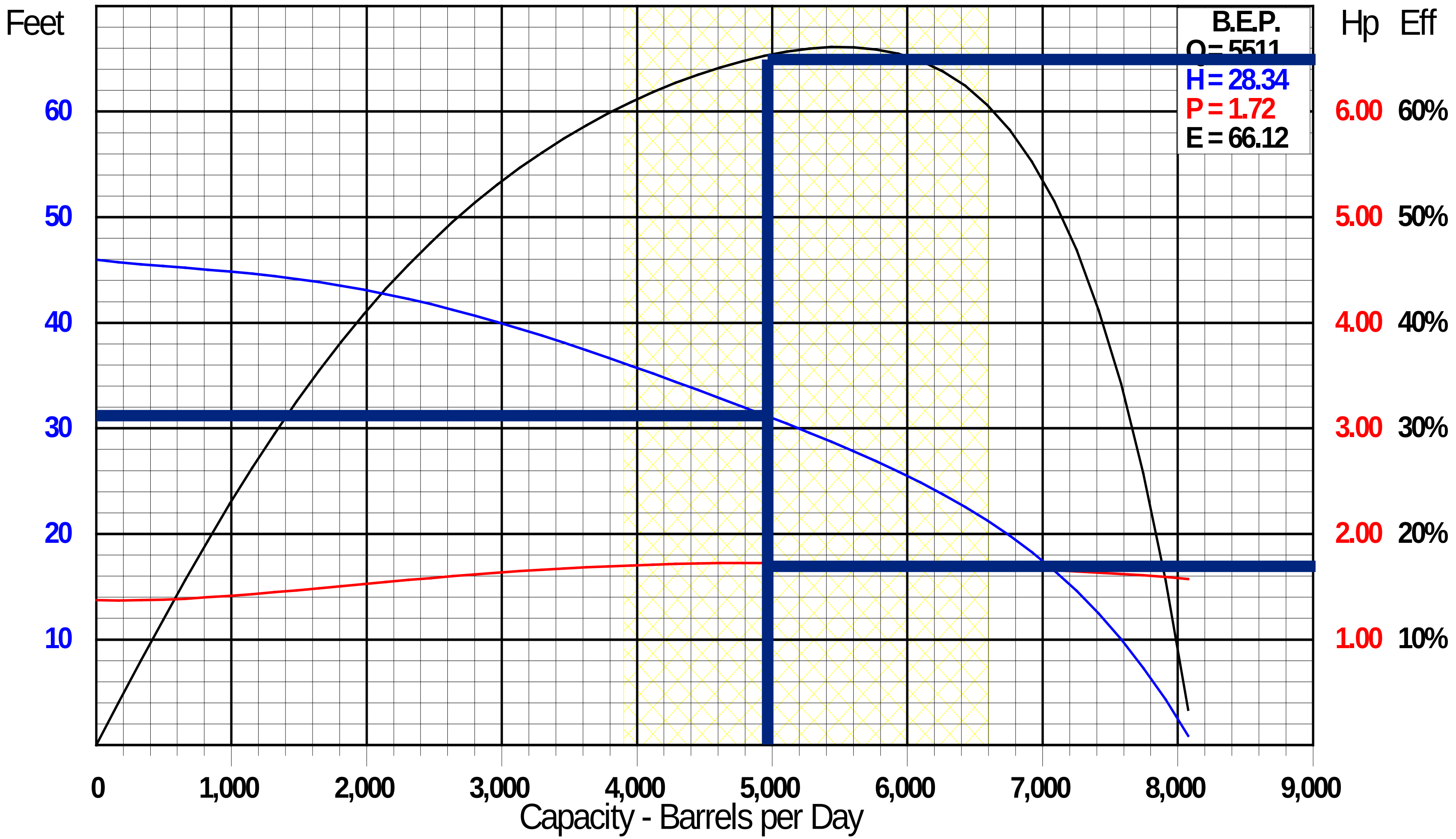
REDA Production Systems

Reda Pump Performance Curve
GN5200
540 Series - 1 Stage(s) - 3500 RPM - 60 Hz

Rev. A

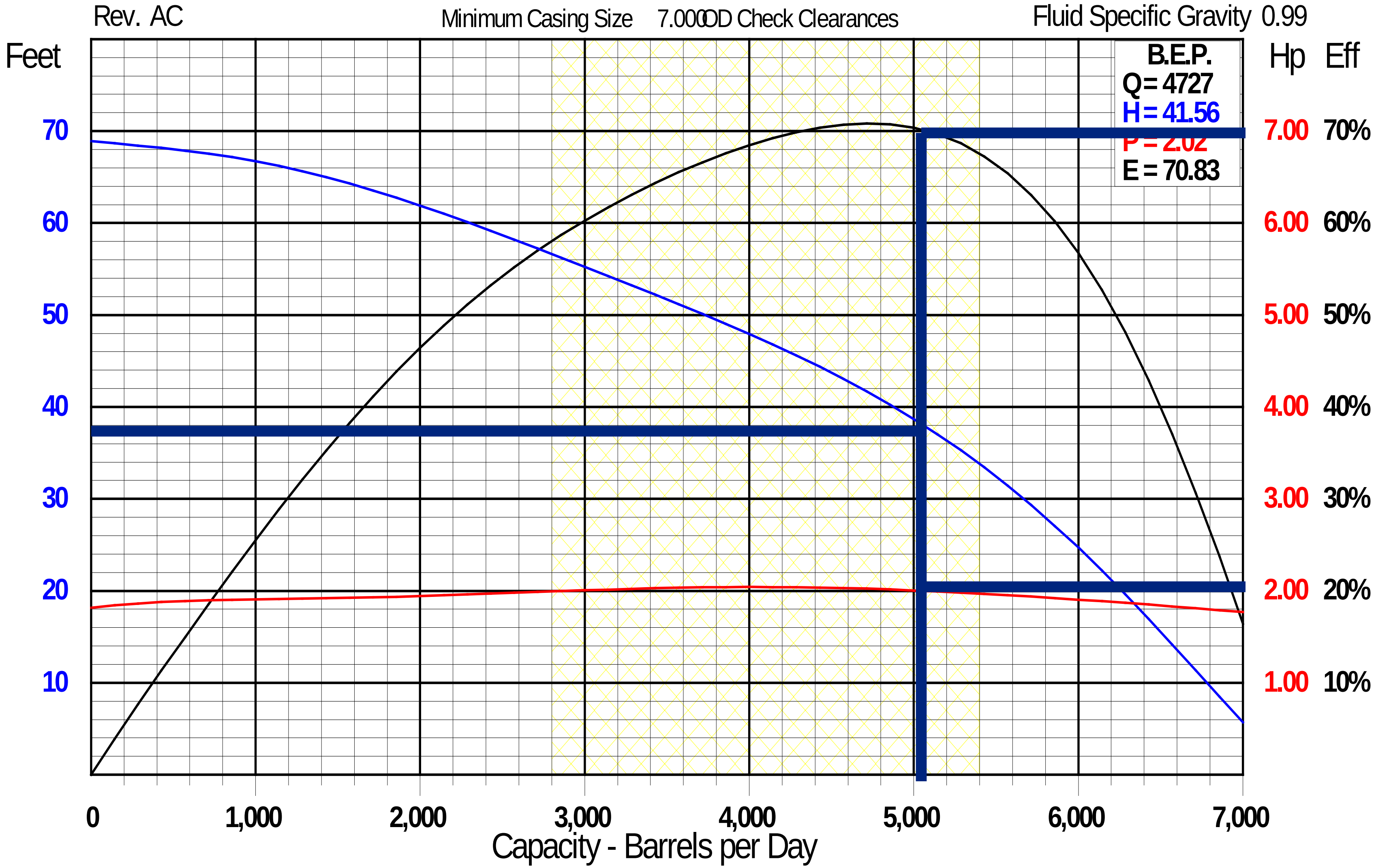
Minimum Casing Size 6.625 OD Check Clearances

Fluid Specific Gravity 0.99



REDA Production Systems

Reda Pump Performance Curve
S5000N
538 Series - 1 Stage(s) - 3500 RPM - 60 Hz



5000 BPD Pump Sizing Lift Per Stage

5765 feet TDH

-------------- = stages required for 5000 bpd

ft/stage

DN5800 = 24’/stage	**=**	**(240 stages)**
GN5600 = 30.5’/stage	**=**	**(189 stages)**
GN5200 = 31.5’/stage	**=**	**(184 stages)**
SN5000 = 38’/stage	**=**	**(150 stages)**

5000 BPD Pump Sizing HP Per Stage

DN5800 = 1.28 hp/stage x 240 stages = 307 hp
GN5600 = 1.65 hp/stage x 189 stages = 312 hp
GN5200 = 1.72 hp/stage x 184 stages = 316 hp
SN5000 = 2.02 hp/stage x 150 stages = 303 hp

NOTE: These required hp's are at the design point only and would not determine the proper motor size! This will be determined by the 'run-out' horsepower **

5000 BPD Pump Sizing Pump Efficiency

DN5800 = 69%	240 stages	307 hp
GN5600 = 66%	189 stages	312 hp
GN5200 = 66%	186 stages	316 hp
SN5000 = 70%	150 stages	303 hp

The DN5800 and the SN5000 are very close.

Which pump is the best choice? Why?

5000 bpd Pump Sizing

The fewer stages and better efficiency will mean that the SN5000 will be less expensive to purchase as well as to operate so let's use it.

The main reason is that the DN5800 pump will require four pumps (58,58,58 & 67 stage and will be 79.6' long).

Also, the DN5800 will require a High Strength Shaft (Inconel), which adds more cost.

The SN5000 will require only two 75 stage pumps – 35' long

Questions?