ARTICLE IN PRESS

Journal of Petroleum Science and Engineering xxx (xxxx) xxx

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: http://www.elsevier.com/locate/petrol

Technobites

A critical comparison of TDH calculation models in manual ESP design procedures

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ARTICLE INFO

Keywords:
ESP pump
Total dynamic head
Pump design
Hand calculation
Comparison

ABSTRACT

The design of an ESP installation is started with the selection of the centrifugal pump, the heart of the system. To choose the ESP pump, one must calculate the installation's Total Dynamic Head (TDH) that is a measure of the required pressure increment to be generated by the pump under the operating conditions. Although this is a basic task in the installation design process, some controversies still exist in the industry about the way TDH should be calculated and many of the standard literature sources recommend an incorrect formula. The paper discusses the available TDH calculation models for single-phase and multiphase flow conditions. The traditional formula widely used in hand calculations is derived and its validity in other than gasless oil production is shown to be highly questionable. The correct formula for single-phase liquid flow is developed, and the calculation error committed by the traditional model is compared to the results of the proper formula. The incorrect model is shown to produce predominantly higher TDH values than the correct one; this fact seemingly increases the safety of pump selection. For increased reliability and in multiphase flow conditions the use of computer programs is advised.

1. Introduction

The heart of an ESP installation is the submersible centrifugal pump that lifts well fluids to the surface. The proper selection of the pump, therefore, has a great technical and economic importance in achieving a profitable production of an ESP installation. The pump chosen must be capable to produce the required liquid rate against the hydraulic resistances in the well represented by the tubing string, and the surface backpressure. At the same time, it should guarantee a minimum of energy (horsepower) requirement and thus provide the least power cost. In summary, proper selection of the ESP pump greatly affects the production economy of wells placed on ESP operations.

Based on the above, the design of an ESP system is started with the selection of the correct centrifugal pump. Usually, system design is based on a desired liquid rate that limits the types of pumps to be considered. For a proper design, the pressure conditions of the candidate pumps must be consistent with the flow conditions of the given well at the design liquid rate. During normal operation, the pump should discharge the liquid with enough pressure to overcome the pressure losses occurring along the flow path from the pump setting depth to the surface separator. This sets the required discharge pressure of the ESP pump, while its suction pressure is controlled by the pressure of the static liquid column present in the annulus.

Pumps, in general, increase the pressure of the produced fluid from pump suction pressure to pump discharge pressure. The difference between these two pressures is called the pump's "pressure increment" or "differential pressure". In the ESP industry this is normally converted to hydraulic "head" and is designated as TDH, i.e. Total Dynamic Head. This is a very basic parameter in the selection of the ESP pump because it facilitates finding of the number of pump stages to be used; it must be calculated from the pressure conditions in the well while the desired amount of fluid is produced.

2. Basics of TDH calculations

Total Dynamic Head, TDH, in general, is found from the difference of the pump's required discharge pressure and the available suction pressure, a.k.a. the pump differential pressure.

The components of the pump discharge pressure are:

1. The wellhead pressure valid at the given liquid production rate. It is found from the separator pressure and the pressure losses along the flowline.

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https://doi.org/10.1016/j.petrol.2020.108210
Received 20 October 2020; Accepted 30 November 2020
Available online 15 December 2020

Please cite this article as: Gábor Takács, *Journal of Petroleum Science and Engineering*, https://doi.org/10.1016/j.petrol.2020.108210

2. The hydrostatic pressure of the liquid column occupying the tubing string above the pump; this is calculated from the true vertical depth (TVD) of the pump setting depth and the pressure gradient of the produced fluid.
3. The frictional pressure drop occurring in the tubing string valid at the given flow rate. When calculating the frictional losses, in rigorous calculations the measured depth (MD) of the pump is used in the Darcy-Weisbach equation along with the friction factor found from the Moody diagram.

Pump suction pressure, on the other hand, equals the pressure in the well's annulus at the depth of pump intake because ESP wells normally have their casing-tubing annular space open to the wellhead. Called pump intake pressure, PIP, it can be calculated either from the casing-head or from the sandface by summation of the appropriate flowing pressure losses.

Finally, TDH is easily found from the pump differential pressure (discharge minus suction pressures) after converting pressure to hydraulic head by using the flowing pressure gradient of the produced fluid.

3. TDH calculation models

3.1. The original approach

Application of ESP systems has a history of nearly a hundred years. In the early times they were mainly utilized to produce single-phase liquid (oil) without much gas production. The flowing pressures in such a well are shown in Fig. 1 where typical pressure traverses in the tubing string and in the casing-tubing annulus are depicted. The basic assumptions in the following discussion are: (a) water production is zero, (b) negligible gas rate is produced, (c) the casinghead is open to the atmosphere.

The required pump discharge pressure is easily found from summing up the wellhead pressure, the hydrostatic pressure of the oil column in the tubing, and the frictional pressure loss in the tubing string:

$$p_d = WHP + L_{set}\, grad_o + \Delta p_{fr} \qquad 1$$

where: p_d = pump discharge pressure, psi, WHP = producing wellhead pressure, psi, L_{set} = TVD of the pump setting depth, ft, Δp_{fr} = frictional pressure loss in the tubing string, psi, $grad_o$ = hydrostatic pressure gradient of the produced oil, psi/ft.

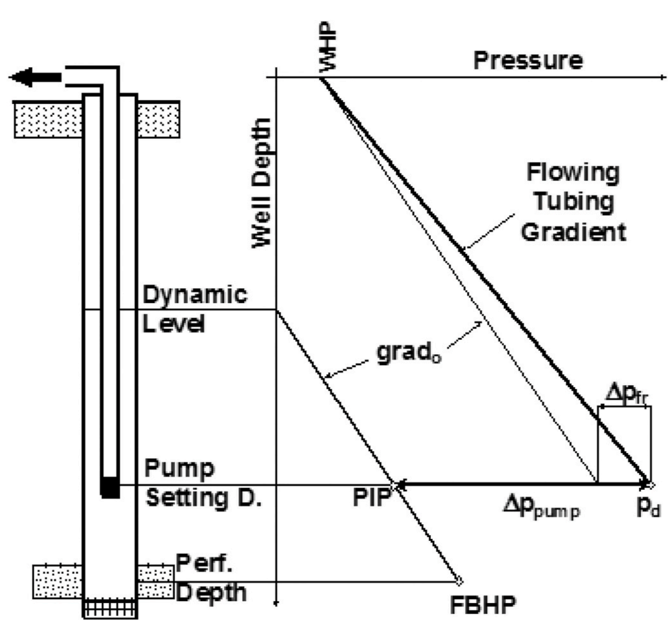

Fig. 1. Pressure distributions in an ESP installation producing gasless oil.

The pump's suction pressure, PIP, can be calculated from the hydrostatic pressure exerted by the static oil column in the casing annulus above the pump.

$$PIP = \left(L_{set} - L_{dyn}\right) grad_o \qquad 2$$

where: L_{dyn} = TVD of the liquid level in the annulus, ft.

The required pump differential pressure is calculated as $\Delta p_{pump} = p_d$ – PIP:

$$\Delta p_{pump} = WHP + L_{dyn}\, grad_o + \Delta p_{fr} \qquad 3$$

TDH is found after converting pump differential pressure to hydraulic head as follows:

$$TDH = \frac{WHP}{grad_o} + L_{dyn} + \frac{\Delta p_{fr}}{grad_o} \qquad 4$$

This is the formula that had been in use since the early days of ESP applications. Sometimes the term L_{dyn} is called "Net Lift" that is said to represent the vertical distance from where the oil is lifted to the surface.

A closer look at the derivation of Eq. (4), and at Fig. 1 proves that the formula is only valid if the liquids in the tubing string and in the annulus are identical, in this case oil. Also, the casinghead pressure is assumed to be equal to atmospheric pressure. The combination of these conditions results in a "net" hydrostatic pressure acting on the pump that may be calculated from the dynamic liquid level, L_{dyn}. It is easy to see that this situation will completely change if tubing and annulus fluids have different hydraulic gradients, i.e. contain liquids of different specific gravities. As a result, strictly speaking, this formula must be used in wells producing gasless oil only.

3.2. The case of water-cut liquid production

In most cases with low gas production rates, the well produces wet oil and the tubing string contains an oil-water mixture. The traditional practice of TDH calculations is simple: change the oil gradient to liquid gradient in the formula (Eq. (4)) derived for clean oil to receive the following expression:

$$TDH = \frac{WHP}{grad_l} + L_{dyn} + \frac{\Delta p_{fr}}{grad_l} \qquad 5$$

The probable first occurrence of Eq. (5) was published by Centrilift in their famous "9-Step" leaflet (1975) that was reprinted many times. It was also included in K. Brown's legendary series on artificial lift technology (Brown, 1980). The same formula was presented in materials of various training courses held by major companies like Shell and Schlumberger (Electrical Submersible Pump Training, 1998; TDH.pdf, 2000; https://production-technology.org/esp-design-step-4-total-dynamic-head/; Electrical Submersible Pumps).

Although the above list may not be complete, the age-old approach of calculating TDHs is still used and ESP designs made by hand may incorporate this inherent error even today. The author confesses having made the same mistake in his book on ESPs (Takacs, 2017) and can only hope that this paper may clarify the problem to people involved in ESP design.

To show the inherent error of this solution Fig. 2 is presented where typical pressure traverses in an ESP well producing a water-cut oil are shown, incorporating the following general observations:

- The static liquid column in the annulus above the pump contains oil only because of the natural separation of phases,
- The casinghead is under a positive pressure because it is connected to the flowline.

Similarly to previous derivations, the required pump discharge and differential pressures are found from the following formulas:

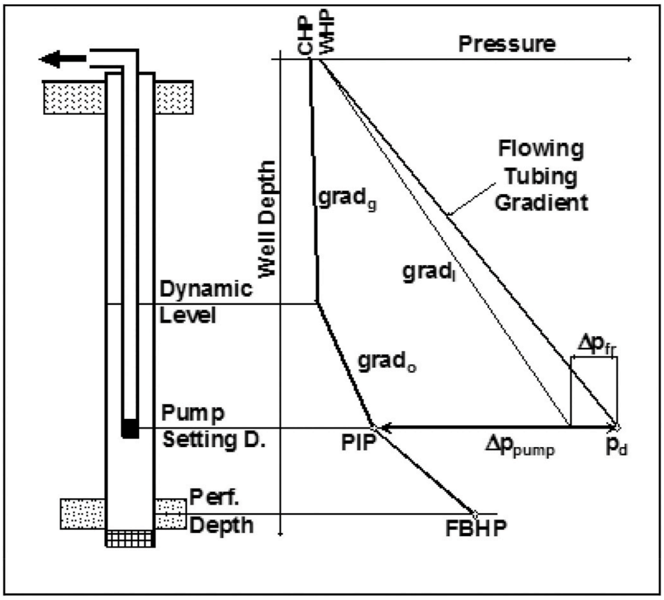

Fig. 2. Pressure distributions in an ESP installation producing water-cut oil.

$$p_d = WHP + L_{set}\, grad_l + \Delta p_{fr} \quad 6$$

$$\Delta p_{pump} = WHP + L_{set}\, grad_l + \Delta p_{fr} - PIP \quad 7$$

TDH is calculated using the hydrostatic pressure gradient of the liquid flowing in the tubing string, $grad_l$; the resultant formula is:

$$TDH = \frac{WHP}{grad_l} + L_{set} + \frac{\Delta p_{fr}}{grad_l} - \frac{PIP}{grad_l} \quad 8$$

As seen, this formula greatly differs from Eq. (5) that was developed from Eq. (4) valid for pure oil production. It includes the pump's intake pressure, PIP, that is calculated by summing the following pressures in the casing annulus: (a) casinghead pressure, CHP, (b) gas column pressure, and (c) the pressure of the static oil column above the pump, as given below:

$$PIP = CHP + L_{dyn}\, grad_g + \left(L_{set} - L_{dyn}\right) grad_o \quad 9$$

where:PIP = pump intake pressure, psi, CHP = producing casinghead pressure, psi, L_{set} = TVD of the pump setting depth, ft, L_{dyn} = TVD of the dynamic liquid level, ft, $grad_o$ = pressure gradient of the produced oil, psi/ft, $grad_g$ = pressure gradient of the gas, psi/ft.

The accurate formula, Eq. (8), appeared in the later editions of the famous "9-Step" design procedure (Nine Step Book, 2007; ESP Handbook, 2007), as well as in the most recent edition from Baker Hughes (Submersible Pump Handbook, 2011). Other key sources worth mentioning are the API Recommended Practice API RP 11S4 (2002), Weatherford's design book "ESP Application Guide" (ESP Application Guide, 2007), SPE's Petroleum Engineering Handbook (Lake, 2006), as well as PetroWiki, the online service maintained by SPE. (https://petrowiki.org/ESP_design#Step_four:_total_dynamic_head_.28TDH.29).

3.3. Comparison of the two models

As already mentioned, the traditional model of hand calculating TDHs in wells producing wet oil utilizes Eq. (5) that is a modification of Eq. (4) with the substitution of liquid gradient instead of the oil gradient. The calculation error, compared to the use of the properly derived formula (Eq. (8)), is discussed in the following.

The difference between Eq. (8) and Eq. (5) can be expressed as:

$$\Delta TDH = \left(L_{set} - L_{dyn}\right) - \frac{PIP}{grad_l} = FOP - \frac{PIP}{grad_l} \quad 10$$

where:ΔTDH = deviation of TDH values, ft, FOP = fluid level above pump, ft, PIP = pump intake pressure, psi, $grad_l$ = pressure gradient of the produced liquid, psi/ft.

Errors in TDH calculations defined by this equation are plotted in Fig. 3 for selected fluid properties, water cuts, and fluid levels (FOP values) in function of the pump intake pressure, PIP. Positive errors indicate that the traditional method underpredicts, negative errors indicate that it overpredicts the correct TDH values.

Each line representing the calculation error for 0% water cut starts at the minimum possible PIP that is found from the FOP and the pressure gradient of the oil produced. These points are indicated by small circles. Points on any of the lines indicate the increase of PIP due to the combined effects of the casinghead pressure, CHP, and the pressure of the gas column in the annulus.

The main conclusions drawn from the figure are:

- In most cases, the traditional method results in overpredicted TDHs.
- Overprediction linearly increases with increased PIPs.
- Increased water cuts reduce the calculation error.
- Calculation error decreases with an increase of FOP.

These results should sound comforting to people still employing the old, and biased model based on the age-long original approach of TDH hand calculations. As shown in Fig. 3, the traditional model almost always results in overdesign and predicts higher than necessary TDHs. Because the selection of the number of pump stages is based on the calculated TDH value, the chance of selecting pumps that develop less than needed TDH is eliminated. On the other hand, an overdesigned pump might not provide optimum operating conditions of the ESP installation.

3.4. The universal calculation model

Description of a universal calculation model is simple: use the definition of TDH as the head corresponding to the required pump differential pressure, i.e. the difference between the required pump discharge pressure and the available pump intake pressure. In this process the only problem is the calculation of discharge pressure. For single-phase liquid flow, use of Eq. (8) is recommended, but in wells producing a significant amount of free gas the determination of the required pump discharge pressure involves multiphase flow calculations in the tubing string. Because these are cumbersome or even impossible to do manually, utilization of special computer programs is necessary.

One excellent discussion of the universal TDH calculation model was provided by Wood Group ESP (2007). Available computer programs from major manufacturers, of course, all use the above principle and can be used to design reliable ESP installations (IHS Energy Group, 2001; Baker Hughes, 2020). Their accuracy, however, is greatly affected by the correctness of the input data, especially those related to the inflow performance of the well.

4. Conclusions

Most of the discussions in this paper relate to ESP installation designs performed by hand only; in such cases problems in the calculation of the TDH values may occur because of different assumptions of the available solutions. The error committed by using an outdated formula is investigated and a way to calculate its extent is proposed. After an investigation of the impacts of the parameters affecting TDH errors it is demonstrated that most often the use of the incorrect formula gives over-predicted TDH values. These, in turn, increase the safety of ESP pump selection because the required number of pump stages is increased

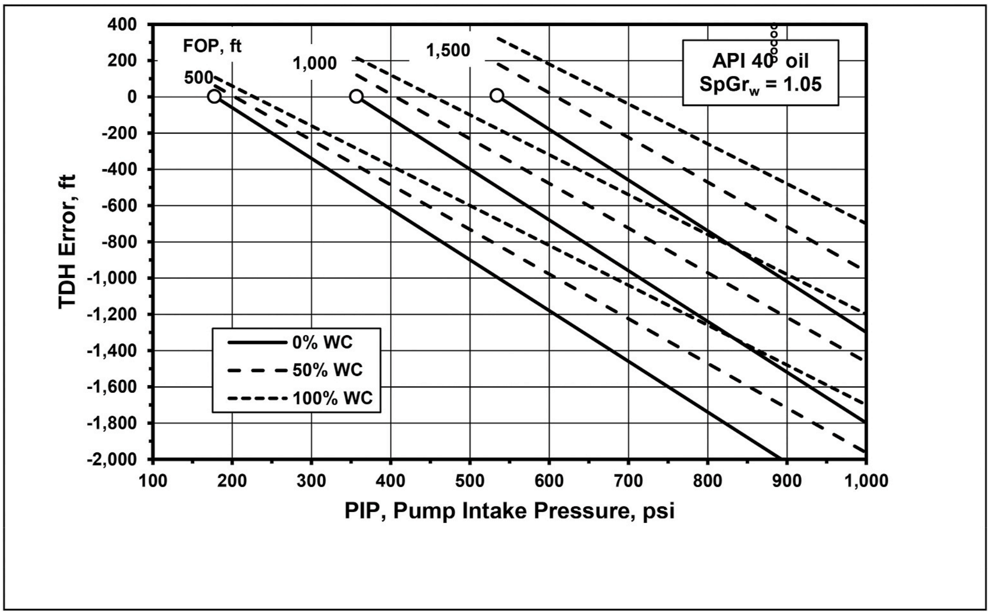

Fig. 3. Typical errors of traditional TDH calculations.

by this practice. This kind of behavior, however, might not result in an optimum ESP system installation that could be provided by a computerized solution.

Computerized design procedures provided by major manufacturers do not rely on simplified formulas to calculate the TDH and, therefore, provide an accurate selection of the ESP pump. Their accuracy, however, highly depends on the reliability of the input parameters, especially those describing the well's inflow behavior.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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