Optimizing Downhole Pump Selection to Production Well Characteristics by Evaluation of Previous Pump/Well Performance

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Introduction

The subject title may be best explained by the following definitions:

Optimizing: To increase production flowrates in gallons per minute (GPM) and/or increase efficiency (lower parasitic input loads versus output flowrates). Optimizing can also be used to describe relatively minor adjustments in settings at sufficient depths to prevent flashing, increase flowrate and/or lower shaft mechanical friction losses.

Pump Selection: The impeller model type and the required number of stages. Typical impeller types are described below. (B.E.P. GPM = best efficiency point flowrate)

MODEL	B.E.P. GPM
low	800-1,200
medium	1,200-1,500
high	1,400-1,800

NOTE: The indicated flowrates are geothermal industry standards. Lower and higher B.E.P. GPM models are available, but not by all manufacturers.

Well Characteristics: In a broad sense, all that is known about the well, such as profile, production temperature, productivity index, drawdown and/or dynamic level at any given flowrate, flash point, depth to first obstruction (such as liner hanger), differential zone perforations, paper scale and/or excessive sanding history, well workover history (cleanouts, acidizing) etc.

Previous Pump/Well Performance: Essentially, before the degradation/failure of the previous pump (while new and operating at its supposed optimum), what was the recorded Pd, Pa, Pb @ Lb, temperature, I (amps), E (volts)? These values, although useful, provide only a "snapshot" and little about capabilities. An actual test (throttled to wide-open valve to pond or tanks with non-flashing @ Pd or Pb and freshly purged bubble tube readings at each test point) can provide a wealth of data where "snapshot" data alone leaves too much to experience and/or guesswork without sufficient confidence of reliability. (see **Multiple Point Field Test).**

Cautionary Notes

1.) Know the flash point of this particular well. Do not make assumptions based upon similar wells or rely upon Steam Table values. Run a gas bomb test. During pump test (or normal operation), never allow Pb (or Pd) to drop to flash point pressure.

2.) After start-up, allow sufficient time for thermal equilibrium, wellbore and drawdown stabilization before interpreting data. This may take one to two days to as long as weeks. Let stable temperature, GPM, Pa and Pb be your indicators. At a constant Pd, GPM and Pb should decrease and Pa increase until these values level off. This is the well and pump settling-in.

3.) Is there any detectable communication between this production well and that of other producers? Injectors? Is there stability in the overall reservoir pressure? If it is declining rapidly, flowrate capabilities from the well will decrease in time.

4.) If this well is perforated at dissimilar (temperature and/or chemistry) zones or is already known as a paper scale producer, provide scale inhibitor injection. Such chemical injection; however, provides no protection classical flashing/scaling.

5.) Be assured of field instrumentation accuracies—particularly that of the flowmeter (a Venturi is best but not infallible—e.g., plugging of tubing to gauge works is not uncommon). But other readings are also critical. Check Pd and Pb pressure gauges. Is the bubble tube free of plugs or leaks? Check MCC (ampmeter and voltmeter) displays by computing this to horsepower. If this does not agree with kilowatts x 1.341, then there is an error somewhere.

6.) Be aware that excessive sanding, scaling and/or fill may cause drag and result in artificially higher BHP at anticipated heads. If the well does not clean up, erosion may occur and may lead to a drop in head. A period of sanding is typical of newly drilled wells or wells that have been re-perforated or acidized. Re-perforating wells may have economic payoffs, but it almost always assures dissimilar zones and the need for scale inhibitor injection. Acidizing wells rarely pays off in geothermal production and typically is disastrous. Relatively clean wells become extremely sandy producers when clays (which cement back sands) are dissolved.

Nomenclature Key and Equations

1.) **Pump Performance Curve**—provided by manufacturer to detail performance of bowl assembly (pump), via test lab data, and that of the complete pump installation particular to a given well (setting depth, temperature, etc.). See Figure 1.

a.) **GPM** = United States gallons per minute (universal flowrate units to the geothermal industry as well as to that of pump suppliers); see Equations.

b.) **TBH** = Total bowl head (ft.). Head developed at any given flowrate by pump (bowl assembly). It includes head to overcome column friction losses (fluid moving up through, typically, 9-5/8" API pipe with 3-1/2" SCH 80 lube string) as determined by setting. See Figure 2 chart for column friction losses. TBH=the head per stage at a given flowrate multiplied by the number of stages. TBH@GPM (as well as corresponding bowl efficiency and bowl BHP) are/should be factory test lab values.

c.) **TDH** = Total dynamic head (ft.). TBH column friction losses at any given flowrate. Also called field head; see Equations.

d.) **SP. GR.** = specific gravity of brine. Although actual values no doubt are somewhat higher, conventional steam table values are assumed.

e.) **Bowl BHP** = Bowl brake horsepower of pump (bowl assembly) itself at any given SP. GR., flowrate and TBH (product via number of stages); see Equations.

f.) **Bowl Efficiency** = The efficiency (percent) of bowl assembly itself (GPM, TBH, Bowl BHP considered); see Equations.

g.) **Pump BHP** = Overall complete pump load on motor; Bowl BHP + SMF +TBL at any given flowrate; where SMF (shaft mechanical friction losses) = 4.66 HP loss/100 ft. Setting for industry standard a 2-3/16" diameter line shafting and TBL (motor thrust bearing loss, in HP) is typically minor (less than 5 HP); see Equations.

h.) **Pump Efficiency** = overall complete pump efficiency (percent) with GPM, TDH and Pump BHP considered; see Equations.

NOTE: Pump BHP and pump efficiency values exclude drive motor efficiency. To determine "wire-to-water" values, see Equations.

2.) **Setting (ft.)** = Depth from surface to top of bowls (top of pump or bowl assembly). The total depth of joints installed with industry standard banded continuous tubing for bubbler line, Lb = setting depth when Pb gauge is located at wellhead/pump head (flow tee).

3.) **Gas Bomb** = A pressure vessel device with sight glass windows, valving and pressure gauge. After warming to production temperature, pressure within vessel is varied (lowered) until very small bubble formation is noted. This is the flash point of the produced brine. Pb (as well as Pd) must always be safely greater

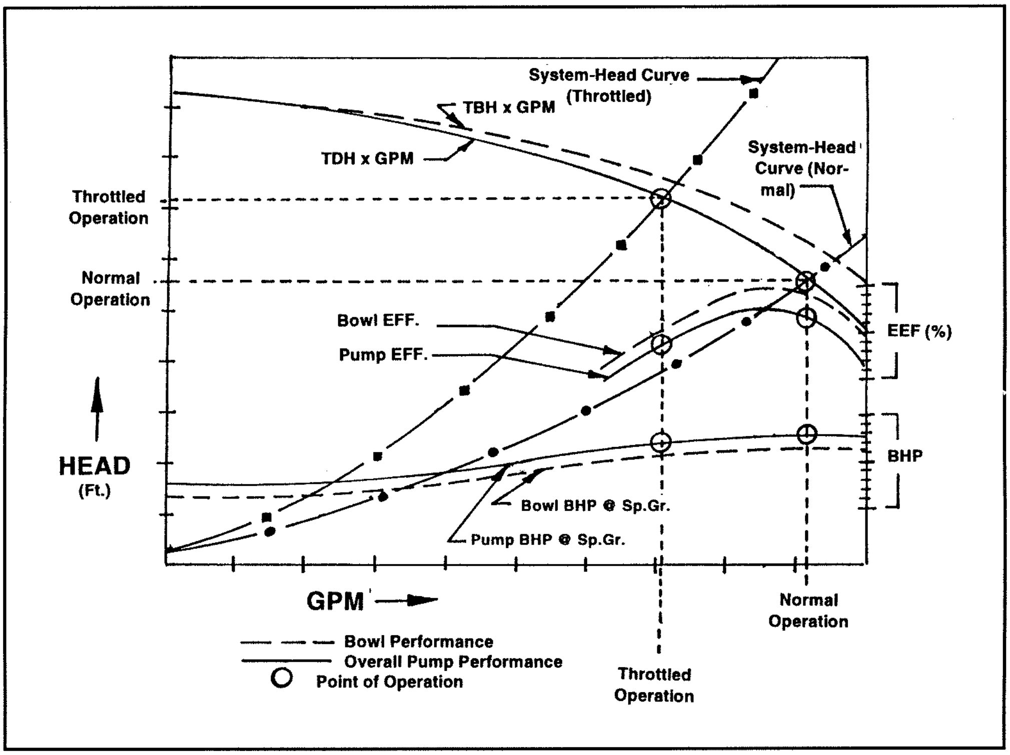

Figure 1. Typical bowl and pump performance with hypothetical system-head curve intersections (normal and throttled).

than pressure value, or flashing, scaling and severe damage to the pump will occur. If Pb is too low, immediately throttle pump, which will increase Pd.

4.) **Drawdown** = The difference in water levels as flowrate increases (expressed properly in ft., but psi is also often used). Drawdown is often erroneously used to describe lift.

5.) **Lift (ft.)** = The distance from dynamic water level to surface.

6.) **Submergence (ft.)** = The distance from the water level to the end of the bubble tube. In actuality this value does not include the length of the pump (bowl assembly) to the suction impeller and is considered a safety margin.

7.) **Key** (also see **Pump Performance Curve** above)

Pd (psig) = surface discharge of pump before valve

Pa (psig) = annulus pressure

Pb (psig) = bubbler tube pressure (freshly purged at each reading) = Pa + Ss

Lb (ft.) = depth of bubble tube installed (plus distance to Pb gauge if not located wellhead/pump head)

I = amperes via ampmeter

E = voltage via voltmeter reading

Me = Electric motor efficiency @ load; see chart below

Mpf = electric motor power factor @ load; see chart below

Me and Mpf values of a typical (General Electric) motor, 800 HP/ 4 pole/ 4,160 volt/ WP-1 enclosure, are as follows. Values; however, are based on a new or relatively new motor that has not been abused or rewound:

LOAD (%)	Me (%)	Mpf (%)
100	92.4	87.5
75	92.6	86.0
50	92.6	80.0

Ls (ft.) = lift or distance from dynamic water level to surface

Ss (ft.) = submergence from dynamic water level to end of bubble tube

8.) EQUATIONS (general)

$$\text{head (ft.)} = \frac{(2.31)\,(\text{psi})}{\text{Sp. Gr.}} \qquad \text{psi} = \frac{(\text{head})\,(\text{SD. Gr.})}{2.31}$$

°F = 1.8(°C)+32 °C = 0.555 (°F-32)

kilowatts=(0.746)(horsepower)

horsepower=(1.341) (kilowatts)

$$GPM=\frac{(Q)(0.00\,19978)}{Sp.\ Gr.}$$

where Q=flowrate in 100,000 lbs/hr

9.) EQUATIONS (calculations for generating pump curve via factory lab tests)

TDH (ft.)=TBH (ft.)-column friction losses (ft.)

$$BOWL\ BHP=\frac{(GPM)(TBH)(Sp.Gr.)}{3{,}960\ (BOWL\ EFF.)}$$

PUMP BHP= BOWL BHP + SMF + TBL

$$PUMP\ EFF.=\frac{(GPM)(TDH)(Sp.\ Gr.)}{3{,}960\ (PUMP\ BHP)}$$

10.) EQUATIONS (field)

$$TDH=\frac{(Pd-Pb)(2.31)}{Sp.\ Gr.}+Lb$$

$$BHP\ PUMP=\frac{(1.73)(I)(E)(Me)(Mpf)}{746}$$

$$PUMP\ EFF.=\frac{(TDR)(GPM)(Sp.Gr.)}{3{,}960\ (BRP\ PUMP)}$$

$$Ss\sim\frac{(Pb-Pa)(2.31)}{Sp.\ Gr.}$$

$$Ls\sim Lb-\frac{(Pb-Pa)(2.31)}{Sp.\ Gr.}$$

Annual parasitic PUMP BRP load ($)=(.0746)(PUMP BHP)(8,760 hrs.)(p)

where p =cost of input in $/kw-hr.

$$\text{"Wire-to-water BHP"}=\frac{PUMP\ BHP}{Me}$$

"Wire-to-water Efficiency"=(PUMP EFF.)(Me)

The Law of Pump Performance

"A pump will always perform at the point at which its performance curve intersects the system-head curve."

1.) The above is true even for a worn pump and also is true if the pump is throttled. (Throttling does not change the pump curve, it changes the system-head curve). See Figures 1 and 3.

2.) The system-head curve is the summation of the head requirements of the system plus friction losses as the flowrate increases. In the most simplistic of terms for a downhole pump, the variables for summation are:

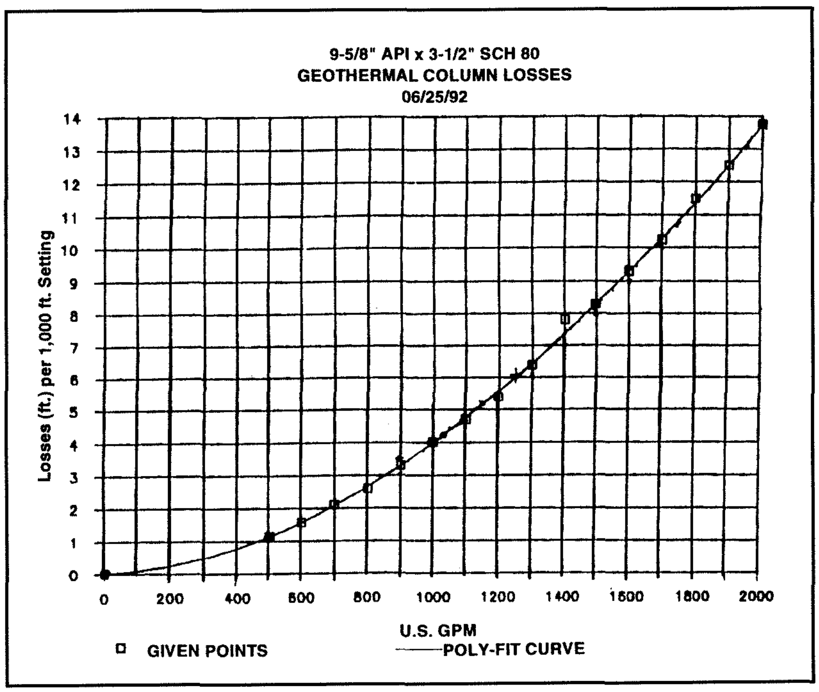

Figure 2. Column friction losses chart—9-5/8 inches API x 3-1/2 inch SCH 80.

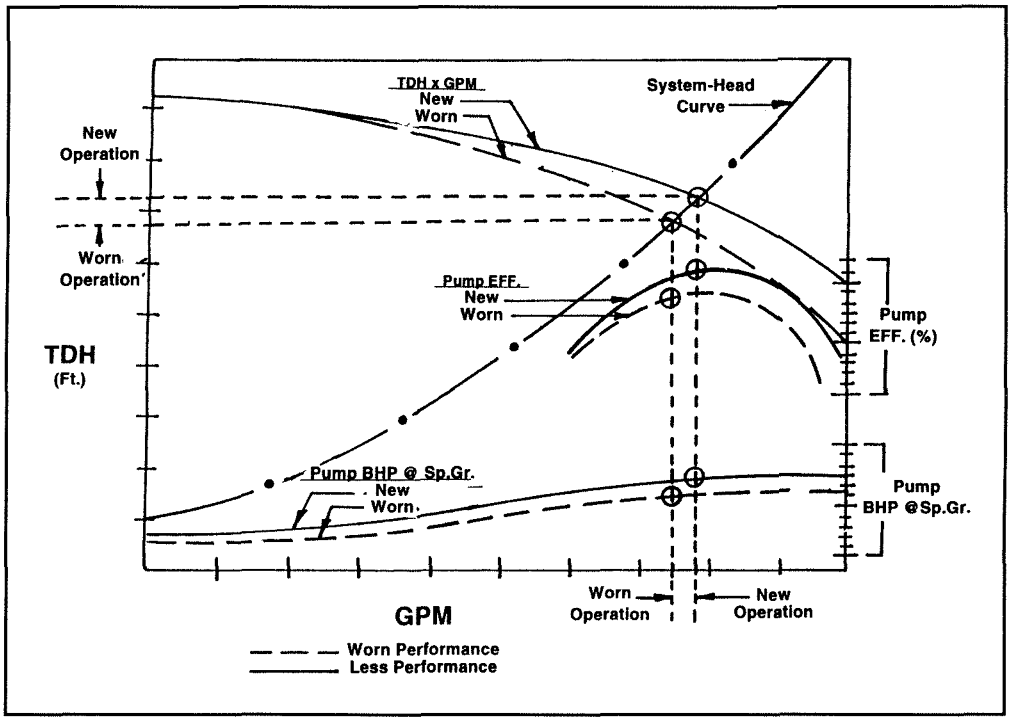

Figure 3. Hypothetical new versus worn pump performances with system-head curve intersections.

a.) Lift or the distance from the dynamic water level to surface (in ft.). This value increases with the flowrate.

b.) Changes in piping elevation from surface of pump/well to end of system. This value (in ft.) is constant regardless of flowrate.

c.) Friction losses (in ft.) in piping from pump/well to end of system. These losses increase along with fowrate. NOTE: Column friction losses are **not** a consideration here as they are losses internal to the pump (must be compensated for by manufacturer) and not losses of the system. See Figure 2.

d.) System pressure or the pressure (converted to head in ft.) required at the end of the system. Most typically the pressure here is more or less constant.

For any given flowrate, the above head values are added. These points form a curve when plotted on a typical pump curve graph in which the vertical axis is head (ft.) and the horizontal axis is flowrate (GPM). For a typical downhole pump, the two most significant variables are lift and system pressure.

3.) The actual system-head curve of any particular well to that of its plant is, in reality, a much more complicated affair with, for example, parallel operation (several pumps of varying flowrates with each of their pipelines valved into a common line before entering the plant.) Not only does this greatly complicate the summation of heads at any given flowrate, but at any given summation of these heads the flowrates of each of the pumps become additive as well. Suffice to say that real system-head curves are, generally, in the geothermal industry not known.

4.) The performance of a multiple point field test does very closely estimate that of the required system-head curve when we consider Pd for normal operation plus field test Pb values at various flowrates. With test data we can easily determine whether a more efficient pump is in order or whether we can increase production flowrates as well.

5.) A classic example of mismatching a pump to a well (the system-head curve) follows: Buyer has a pump in a well with a 1,500 GPM production rate. This pump eventually wears out and is pulled. Buyer installs another (new) pump without considering this pump has different impeller modeling and/or staging. The newly installed pump produces only 1,250 GPM. Buyer, not realizing the error, wonders if there is something wrong either with the well or (mechanically) with the pump.

Evaluating Existing or Previous Pump

1.) Refer to **Multiple Point Field Test**. Although the following evaluation can be performed from operational data records, such data essentially evaluates a single point "snapshot." A single point evaluation is useful but is often inadequate in matters such as determining whether or not a higher flowrate is possible and, if so, which impeller model, how many stages and what setting depth will be required.

2.) Refer to **Pump Performance Curve, Key** and **Equations** (field). For each test point (GPM) calculate TDH, Pump BHP, and Pump Efficiency. Plot these points on that of the pump performance curve provided by the manufacturer.

3.) Refer to **Cautionary Notes**. Assuming the absences of flashing, excessive sanding, paper scaling, errors in instrumentation, etc., a new pump should have field tested points within + or - 3 percent of the curve. (Be aware that even slight values higher in Pump BHP appear or translate into noticeably lower pump efficiency values). Other than areas already mentioned (cautionary notes), is there a justifiable reason for gross differences in field determined results and the anticipated performance of the curve? Some of the following scenarios are common while others are not, although they do happen:

a.) No flow/very low amps—broken line shaft.

b.) Field plotted results form a curve that is almost parallel but grossly below anticipated curve—this could be caused by several possibilities but most likely would be:

1.) Extremely severe erosion through impellers and bowls.

2.) Broken impeller shaft, allowing only a portion of the stages functioning—this can be verified with a spacing (lateral) check.

3.) Plugging at slotting of strainer.

c.) Field results are close to curve at low flowrates with increasingly greater discrepancies and increasingly greater flowrates. Typically:

1.) Pump is simply wornout—rotating clearances severely worn, plus some degree of erosion, which could be significant.

2.) Data is being evaluated beyond "runout" flowrate shown on curve. It should also be noted that there are yet no established friction losses through 9-5/8" API pipe x 3-1/2" SCR 80 lube string settings for 2,000 + GPM.

3.) Increasingly severe flashing downhole with increasingly greater flowrates. The flowmeter may be unstable with flowrate stable at lower flowrates or throttling.

d.) Flowrate to some degree is low/Pa=Pd—leak in pump casing (9-5/8") above dynamic water level. Immediately shut-down and pull pump as pipe will erode, but not before it will scale-up to well casing.

e.) Flowrate to some degree low /Pa and Pb noticeably increase with increasing flowrate—see above. Pump casing leak below water level and may be at sufficient depth to prevent flashing.

It should be noted for simple cases of a pump wearing-out that while Pd and Pa are relatively constant, flowrate and amps decrease with Pb increasing. See Figure 3.

Multiple Point Field Test

1.) Refer to **Previous Pump/Well Performance** and **Cautionary Notes.**

2.) The following assume unit is already running to a pond and both well and pump have settled in.

a.) Completely open the valve, making sure flashing is not occurring at either Pb or Pd, and I (amps) are within motor nameplate plus service factor. Purge bubble tube as often as necessary to measure a stable reading and remember to re-purge at *every subsequent test point just before recording.* After all readings (Pd, Pb, Pa, GPM, I, E and temperature) have stabilized, record these values as a snapshot or test point.

b.) Throttle valve somewhat (100 to 200 GPM test point increments are generally advised), allow readings to stabilize, re-purge bubble tube and record all readings again.

c.) Repeat as above to gather several test points with increasing TDH and decreasing GPM.

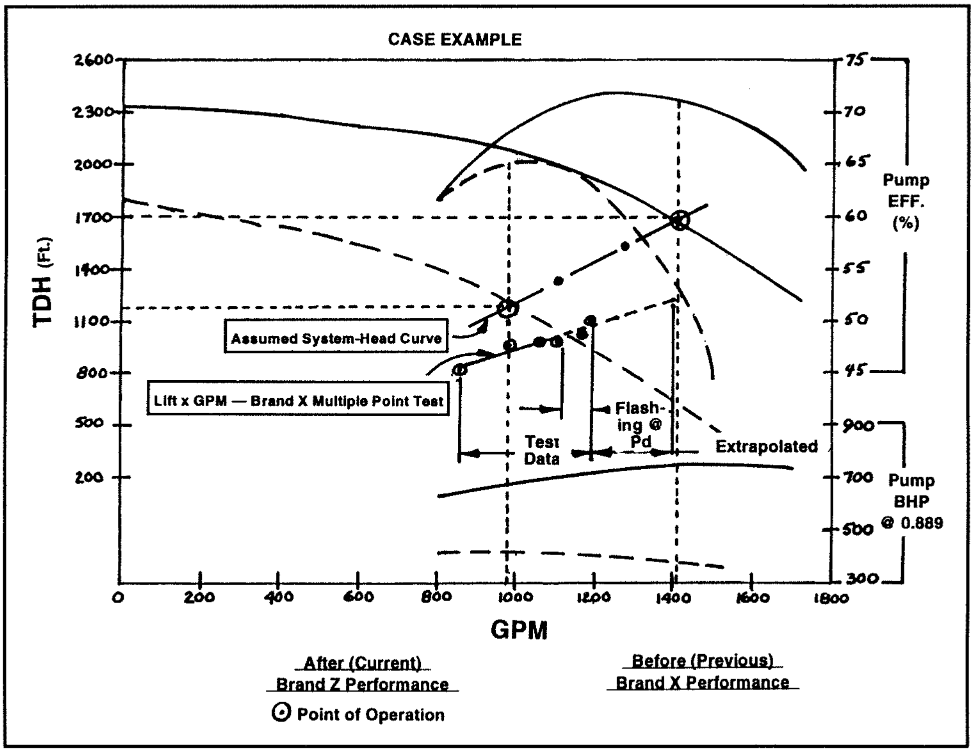

Figure 4. Case Example—Brand X versus Brand Z pump performances.

d.) Valve throttling must be limited to the following general guidelines:

1.) No less than 30 percent of pump's B.E.P GPM.

2.) Pd is not beyond valve or line pressure capabilities.

3.) Typically, increasing Pd induces a higher lube oil pressure. Watch that oil pressure does not exceed mechanical seal capabilities. Maintain proper lube oil flowrate. Do not try to lower oil pressure by overly reducing P.D. pump stroke or allowing bypass. Avoid venting stuffing box.

Optimizing Future Pump Selection

If data from the previously installed pump is sufficient, one can easily determine whether a more efficient pump is advised even from operational (single point snapshot) records, although multiple point test data is far more definitive. To provide a pump that is both higher in operational flowrate and efficient at that flowrate, a multiple point test can eliminate guess work and assumptions when only operational data is available—known drawdowns at increased flowrates not achievable when previous pump was on-line. Who would not want an increased flowrate at increased efficiency? (Typically, a significantly increased flowrate at relatively little increase in amps).

An optimized (more efficient) pump selection, even at higher flowrates, can have an additional and substantial payoff—**longer rotating** life—as the pump may not need to struggle/self-wear itself in to accommodate its performance to that of the system-head curve. There are, however, limits at very high flowrates, particularly if brine is abrasive from sands or scales. The higher the flowrate, the higher the velocity and the higher the erosion (water wearing away stone). If, however, the optimized selection is at the same flowrate but more efficient, a significantly longer life should be realized.

Based on operational data and/or multiple point testing on the last pump installed, simply evaluate:

1.) Was setting depth sufficient to prevent flashing? (If you haven't already, run a gas bomb test). Does setting need to be increased and can pump handle the needed setting?

2.) Assuming setting is constant, will there be ample non-flashing Pb to support a higher flowrate? What will this flowrate be? This is where multiple point testing can eliminate considerable guess work/assumptions.

3.) During normal operation to plant and flowrate was high, what was Pd and GPM?

4.) At the desired flowrate, is there a more efficient impeller model? That is, impeller model whose B.E.P. GPM is close to that of the desired flowrate.

5.) What is the payoff to purchase the optimized pump selection over that of simply replacing or repairing the same unit? Although each case should be taken independently, the evaluation (excluding real rotating life increases) ranges from simple but significant savings in power consumption (at same flowrates/more efficient pump) to much higher flowrates with very little increase in power consumption. This payoff, although significant, can vary greatly from one plant operation (contract) to the next with variable rates for parasitic loads versus revenue. Unless the previously installed pump was already operating near optimum conditions, it almost always makes sense that its replacement be re-sized (provided it can be delivered with a miminal amount of down time—ideally, such a unit should be on location by the time the previous unit comes out of the hole).

Conclusions (In Brief)

1.) Know the flash point of each particular well—perform a gas bomb test. This is a one-time only need, unless new zones open up as is the case, for example, with re-perforations and, in some cases, the event of earthquakes or even cleanouts. Never allow flashing to occur (Pb).

2.) Use scale inhibitor (chemical) injection to bottom of pump strainer in wells that produce from dissimilar zones to prevent paper scaling even with sufficient Pb pressures to prevent flashing.

3.) Check all monitoring instrumentation for accuracy.

4.) Properly install, start, operate and monitor pump.

5.) Note any characteristics that might affect pump performance, such as excessive sanding, paper scaling, etc.

6.) After pump is first brought on-line, allow some amount of time for pump and well to settle-in before evaluation—thermal equilibrium stabilized GPM, Pb, Pa and temperature.

7.) Evaluation of performance for a more efficient future pump selection does not necessarily require a multiple point field test to pond or tanks. This can usually be determined from operational data taken while the pump had been operating at its peak (new and settled-in). In such cases (flowrate is kept constant, but a more efficient impeller model is selected), the reduction in BHP/parasitic loads can result in slight to extremely significant payoffs.

8.) Evaluation of performance for a future higher flowrate pump (that is also more efficient at this higher flowrate), from only that of operational data relies heavily upon guesswork and assumptions. A multiple point test to pond or tanks is highly advised as both Pd and Pb can be lowered and, consequently, flowrate increased to levels not obtainable during normal operation. Such data can have huge payoffs in terms of higher flowrates/ revenue at relatively little increase in BHP/parasitic loads.

9.) Optimizing a pump selection to that of the well also tends to increase the rotating life of the pump, often very significantly. However, a balancing act can occur—extremely higher flowrates increase velocity and, particularly in the presence of abrasives, increase erosion.

Case Example of Previous to Current Pump Selection Optimization *(See Figure 4)*

Client: Confidentiality requested

Previous Pump Installation: "Brand X" pump with low capacity model impellers (1,000 B.E.P. GPM); 1,350 ft. Setting (max. due to location of liner hanger); 800 HP/4 pole/4,160 volt motor.

Peak (when new and settled-in) **Operational Data:**

- 335°F
- 975 GPM
- 260 psig Pd
- 1,350 ft. Lb
- 315 psig Pa
- 78 psig Pa
- 61.61 (3 leg ave. amps)
- 4,150 E (3 leg ave. volts)
- 1,207 ft. TDH (calculated)

- 1,283 ft. TBH (calculated)
- 453 Pump BHP or 337.94 kW-hrs. (calculated)
- 58.7% PUMP EFF. (calculated)

Multiple Point Test of Previous Pump (to pond)

1.) A Gas Bomb Test yielded a flash point of 105 psig.

2.) In this particular case, the most important data to consider is LIFT versus GPM. A Multiple Point Test of the "Brand X" pump was somewhat lacking at higher flowrates (to pond) as the pump proved to be "under-staged." That is, while we would have desired to drawdown the well to Pb at slightly above flash point, this was not possible. At 1,100 GPM plus, the Pd values dropped to below flash point.

3.) LIFT versus GPM data was sufficient enough for extrapolation to an estimated 115 psig Pb at 1,375 GPM. For determination of future (Brand Z) pump, we then need only add the 260 psig Pd requirement to determine the required TDH.

Basis For Future Pump Selection (based upon above test)

- 335-337°F
- 260 psig Pd
- 1,375 GPM
- 115 psig Pb (@ 1,350 ft. Lb)
- 1,727 ft. TDH (calculated)
- 1,824 ft. TDH (calculated)

Anticipated Performance of Future Pump (Brand Z)

- 1,375 GPM
- 1,828 ft. TBH
- 1,731 ft. TDH
- 691.3 Bowl BHP
- 756.3 Pump BHP
- 70.7% Pump EFF.

Actual Performance of Current Pump (above Brand Z unit) Installed

- 337°F
- 1,410 GPM
- 260 psig Pd
- 118 psig @ 1,350 ft. setting
- 75 psig Pa
- 98.2 I (amps)
- 4,140 E (volts)
- 1,719 ft. TDH (calculated)
- 762.3 Pump BHP
- 71.4% Pump EFF. (calculated)

Case Example Profitability

As the cost of parasitic load versus revenue for any given plant may differ greatly, no assumptions are herein applied, let alone for that of increased pump (rotating) life. However, the above case example when applied to any given plant's considerations will no doubt illustrate an obvious advantage for "pump to well" optimization.

Case Example Summary

	BEFORE	AFTER	DIFFERENCE
GPM	975	1,410	+ 435 GPM
TEMP (°F)	335	337	+ 2 °F
PUMP BHP	453	762.3	+ 309.3 BHP
PUMP KW-HR	337.94	568.67	+ 230.73 KW-HR
PUMP EFF.	58.3%	71.4%	+13.1 pts. EFF.
ROTATING			
LIFE AVE. (MONTHS)	10.9	27 +	+16 months to date and still counting.*

**To date, unit operating within 3.28 % of curve.*

Considerations Not Discussed Within This Paper/Topic

1.) **Newly Drilled Well**—Even with the advent of Spinner/Temperature/Pressure (STP) surveys and flow testing (natural or artificially stimulated), and within an already exploited KGRA, pump sizing data for a new drilled well is ball park at best. The old adage that "You really don't know what you've got, or what you might be able to make of it, until you pump it" is as true as ever.

2.) **Installation Procedures**—The improper installation of even a superior pump is doomed to premature wear/failure (lube string tension, in particular, is critical).

3.) **Operator Error**—As defined in the most simplistic terms of proper lubrication and proper impeller spacing (lateral) prior to start-up; operator error has become today a relatively unlikely event.

4.) **Start-up Procedures**—Either through the practice of warming up the line to the pump (with flowing down the annulus) prior to start-up **or** direct start-up with even a slight by-pass down through the annulus, the operator is inviting severe damage to entire downhole unit. Such damage may reveal itself, with loss of bubble tube but may eventually expose itself with severe lube string damage. With current environmental constraints (the elimination of start-up ponds), operators/owners will have to accept the necessity of tanks in their replacement or pay a much higher price.

5.) **Electrical Submersible Pumps**—ESPs, at best modified oil-field pumps, have from time to time over the last decade attempted geothermal wells and suffered a high degree of repetitive and frequent failure, combined with an extremely high parasitic load versus flowrate. Although a submersible pump may one day be the future of geothermal production, such a unit will have little, if any, resemblance to that of the oil field type. They will be much more durable, far more efficient and be competitively priced to that of the proven lineshaft unit.