MEDIA CLIPS & VIDEO

- Reciprocating Rod Lift Systems
- Progressing Cavity Pumping Systems
- **Hydraulic Lift Systems**
- Gas Lift and Plunger Lift Systems
- Electric Submersible Pumping Systems
- Wellsite Optimization

INTRODUCTION

Hydraulic pumping systems, as a means of artificial lift in oil production, were first introduced in the early 1930's. Since that time, numerous developments and technological advances have been incorporated, all directed toward maximizing equipment reliability and minimizing "down time". Today, thousands of oil wells – worldwide – are being successfully and economically produced using hydraulic pumping systems.

The hydraulic pumping system operates employing the basic law of hydraulics. This law states that a pressure exerted on any surface of a contained fluid is transmitted with equal intensity to all surfaces containing the fluid. The hydraulic pumping system applies this principle to pumping oil wells by transmitting fluid pressure from a surface source to one or more subsurface points. At these subsurface points, the power fluid, under pressure, is directed to the production unit – either to stroke a reciprocating pump or to provide the velocity head to operate a jet pump. The power fluid utilized by modern hydraulic pumping systems comes from the well itself and can be crude oil or water.

The purpose of this publication is to provide a training manual and reference book for use by Weatherford Artificial Lift Systems field sales and service personnel and customer personnel desiring additional information on hydraulic pumping.

APPLICATION OF HYDRAULIC PUMPING SYSTEMS

Generalities are always somewhat dangerous, since there can be exceptions to the guidelines. However, the following is the common application range for these systems:

	Lift Depth	BPD – Total Fluid
Reciprocating Pumps	1,500’ to 15,000’	50 to 1,600
Jet Pumps	1,500’ to 10,000’	100 to 12,000
Surface HP Range	30 to 275 and higher	

ADVANTAGES OF THE HYDRAULIC PUMPING SYSTEM

All Systems

1. “Free” type pump, easily retrieved for service without the expense and time delay of a pulling unit and service crew.
2. Easily controlled changes in pumping rate over a wide range of capacities. This allows rapid “trimming” of the system to accommodate changing well conditions, such as the effect of water flooding or declines in well production capability.
3. Chemical treatment for paraffin and corrosion control and emulsion breakers can be injected with the power fluid. Fresh water can also be injected to dissolve salt deposits.
4. Can be applied to crooked, deviated, or horizontal holes without tubing wear and horsepower loss due to sucker rod drag, as would occur with rod pumping systems.
5. Can be applied to single or multiple well installations.
6. Compatible with central or automated production facilities.
7. Available in pre-engineered, skid mounted, packaged surface power units allowing quick hook-up and high mobility for future use on different locations.

Reciprocating Pumps

1. High volumetric displacement efficiency. Under suitable conditions, this can be in the 65% to 70% range, or higher.
2. Wide variation in displacement rate by adjusting pump speed through control of power fluid rate
3. Can produce a well to depletion.

<u>Limitations</u>

As is the case with all positive displacement pumps, the hydraulic reciprocating pumps are limited in their ability to handle free gas, high sand cuts, or highly corrosive fluids. Specific bottom hole assemblies can be applied to minimize these problems.

Jet Pumps

1. High reliability of down well equipment due to lack of any moving parts.
2. Higher tolerance of high sand cuts due to abrasion resistant materials in the pump throat and nozzle.
3. Can be supplied in corrosion resistant materials of construction.
4. Can handle free gas without pump damage.
5. Capable of higher volume production than reciprocating pumps.

<u>Limitations</u>
Typically requires somewhat higher horsepower than reciprocating pumps. Efficiency adversely effected by very low pump intake pressure or very high GOR.

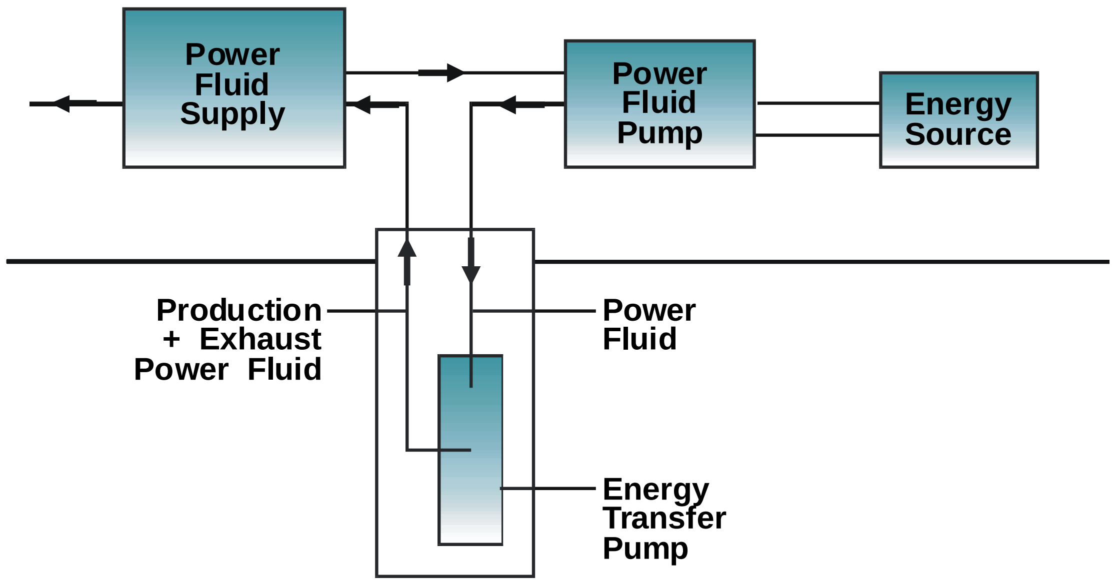
UNIQUE ADVANTAGES OF "OILMASTER" LIFT SYSTEMS

1. Supplied with the National-Oilwell "J" Series Multiplex Pump as the power unit, a pump designed to provide reliable operation under high pressure, continuous duty service.
2. The National-Oilwell "J" Series Multiplex Pump is equipped with a National-Oilwell designed plunger packing system, most commonly the soft packing type. The soft packing is spring loaded to eliminate the need for adjustment and is made of the most modern material available. Plungers are coated with a unique material to provide a hard but extremely smooth surface to maximize plunger and packing life. Stuffing boxes and other associated components are manufactured from corrosion resistant materials.
3. Electric drive units available with an optional four speed manual transmission to allow close matching of power consumption to horsepower need, thus maximizing efficiency.
4. Within the domestic United States, hydraulic pumping systems are backed by Weatherford Artificial Lift Systems field service and repair shops in principal oil producing areas. Service Centers are staffed with trained service and repair personnel equipped with local parts inventory. Surface and subsurface equipment is serviced and repaired locally, eliminating the need for shipment to remote central locations.
5. Leading technology and application knowledge in proper manufacture and selection of jet pumping equipment. Correct sizing from established well data can be performed, using modern computer programs in most regional offices.
6. Systems available in a wide size range from 30 to 625 HP, and larger, to closely match pumping requirements.

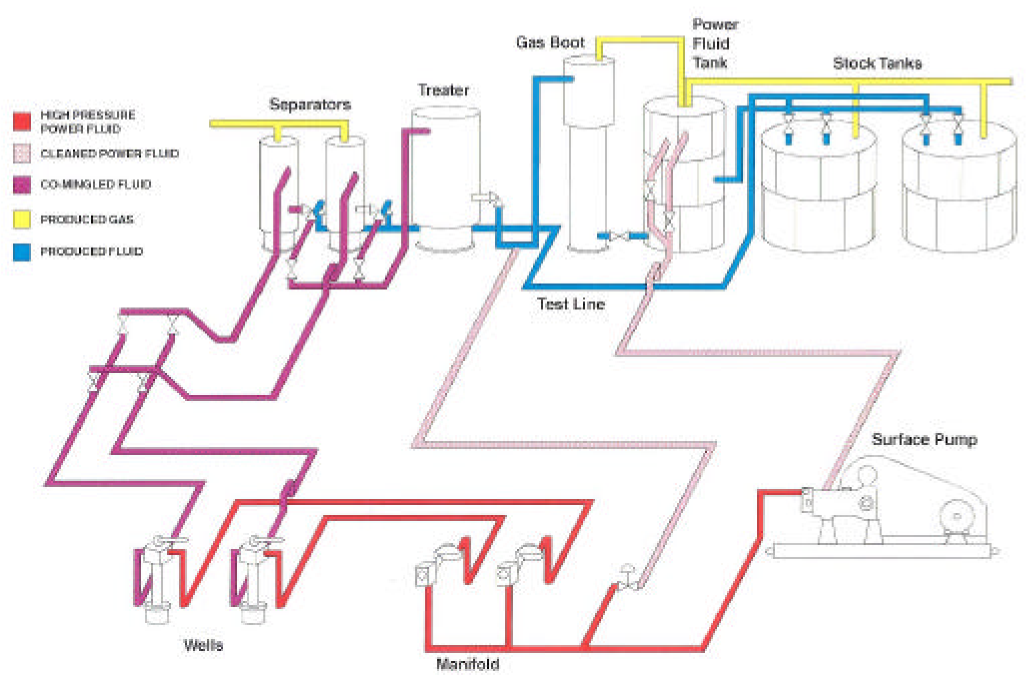
WEATHERFORD HYDRAULIC SYSTEM

1932	First Hydraulic Downhole Pump installed. Established as Kobe, Inc. by C.J. Coberly
1958	Fluid Packed Pump develop Oilmaster Balance-type Hydraulic Pump
1964	Kobe purchased by Baker Oil Tools. Still operated as Kobe, Inc.
1972	Kobe, Inc. ran first Jet Pump to produce oil wells
1972	Fluid Packed Pump introduced patented “Unidraulic” System
1977	Fluid Packed Pump changed name to National Production Systems
1984	Kobe, Inc. purchased by Trico Industries, manufacturer of Sucker Rods and Downhole Rod Pumps
1987	National Production Systems formed joint venture with Oilwell Supply Company
1987	Trico Industries purchased by PACCAR Inc., manufacturer of Trucks
1994	Oilmaster product line (Hydraulic product line of National-Oilwell) purchased by Trico Industries
1997	Trico Industries purchased by EVI
1998	EVI and Weatherford merged to become Weatherford International. Weatherford Artificial Lift Systems is an operating unit of the company

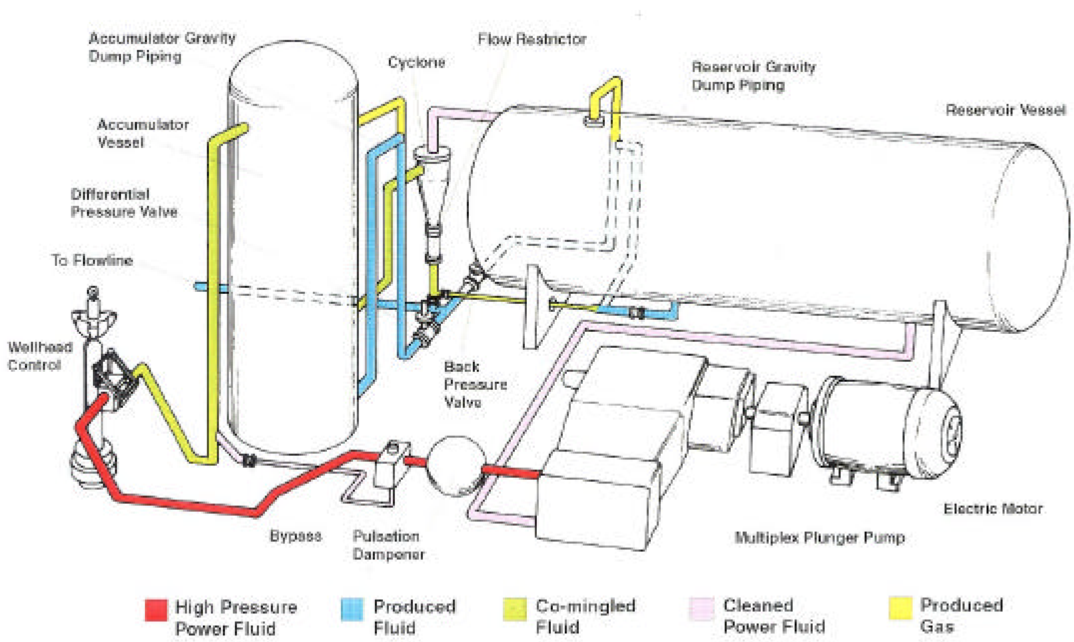
HYDRAULIC PUMPING SYSTEM SCHEMATIC FLOW



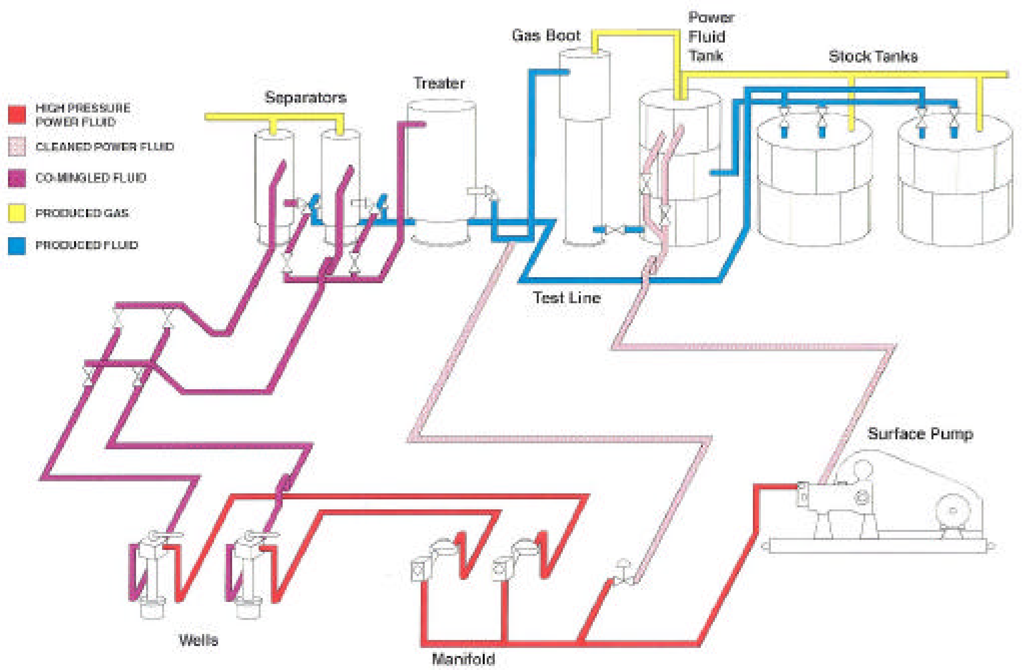
CENTRAL TANK BATTERY SYSTEM



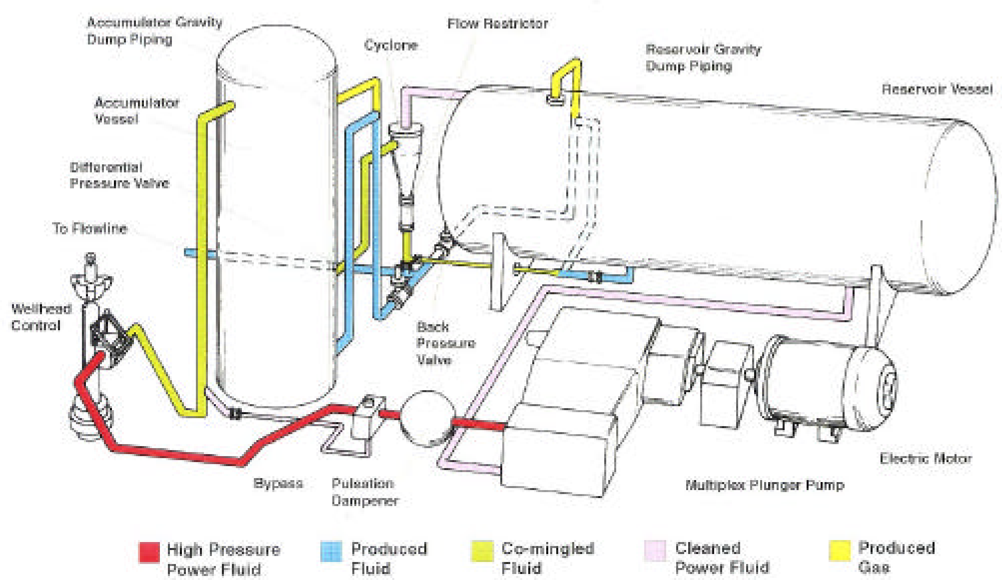
DUAL VESSEL UNIDRAULIC SYSTEM



test



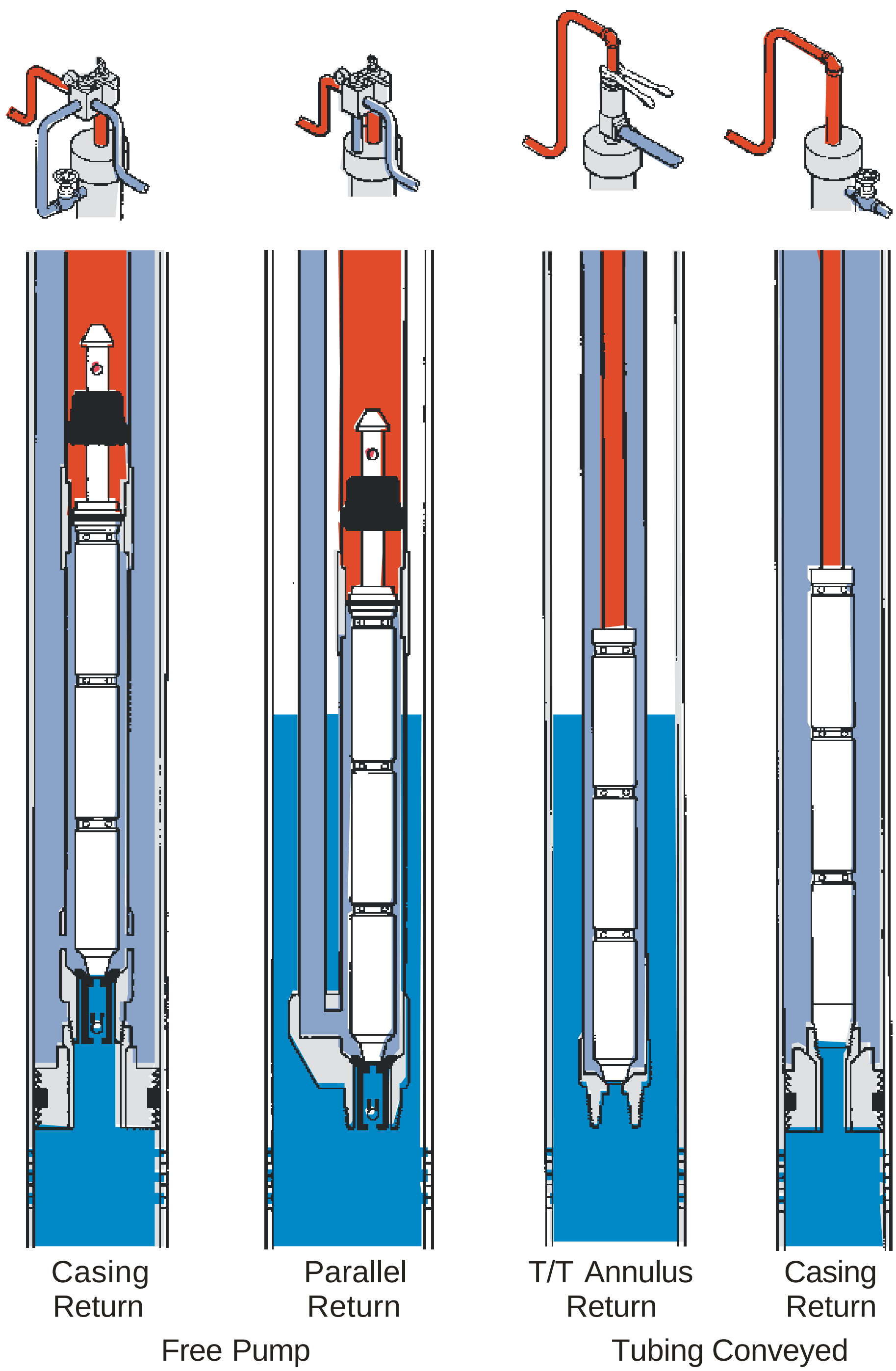
Central Tank Battery System



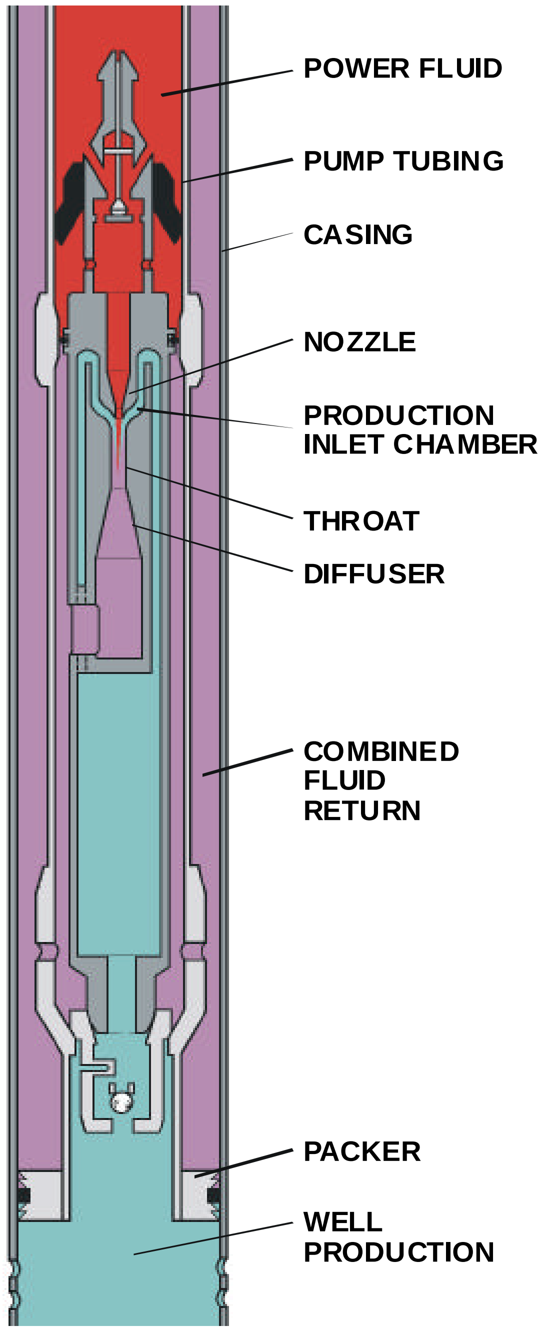
Dual Vessel Unidraulic System

OILMASTER
MODEL 220 PUMP

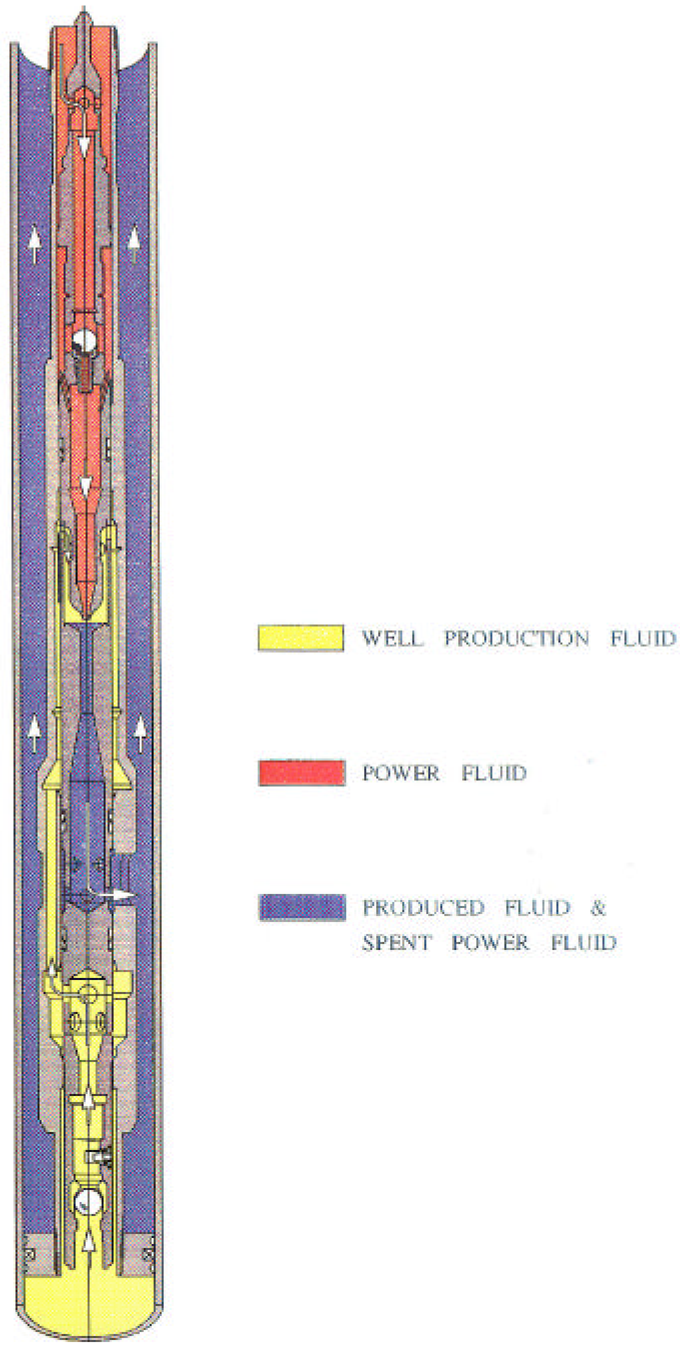
BASIC DOWNHOLE INSTALLATIONS
OPEN POWER FLUID CONFIGURATIONS



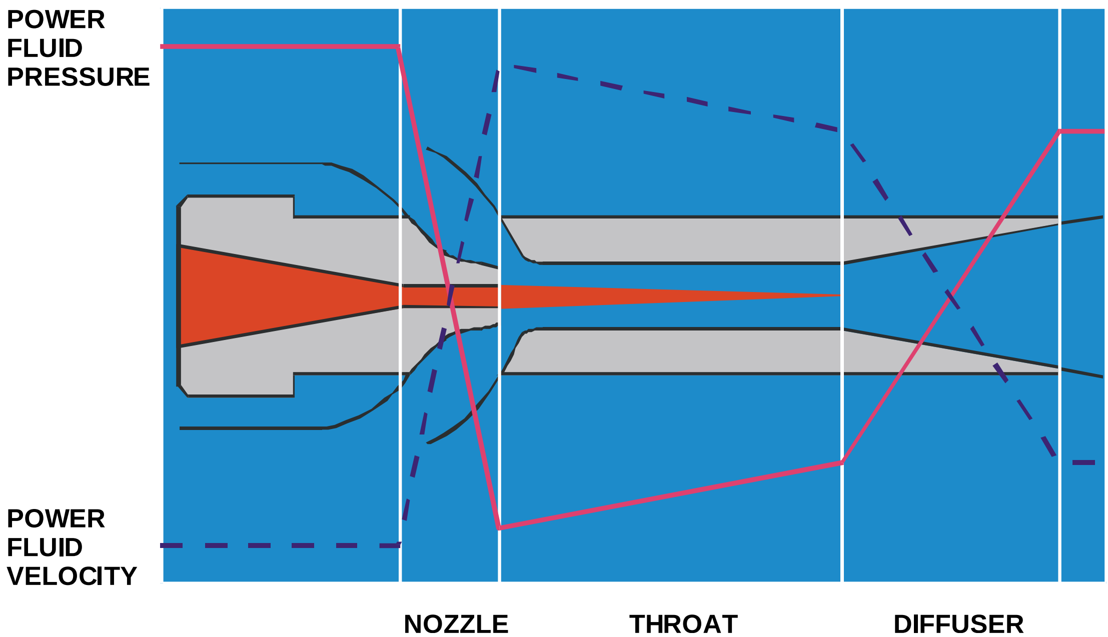
TYPICAL SINGLE SEAL DOWNHOLE JET PUMP



HIGH VOLUME JET PUMP WITH BOTTOM HOLE ASSEMBLY FOR A SINGLE TUBING STRING CASING "FREE" COMPLETION



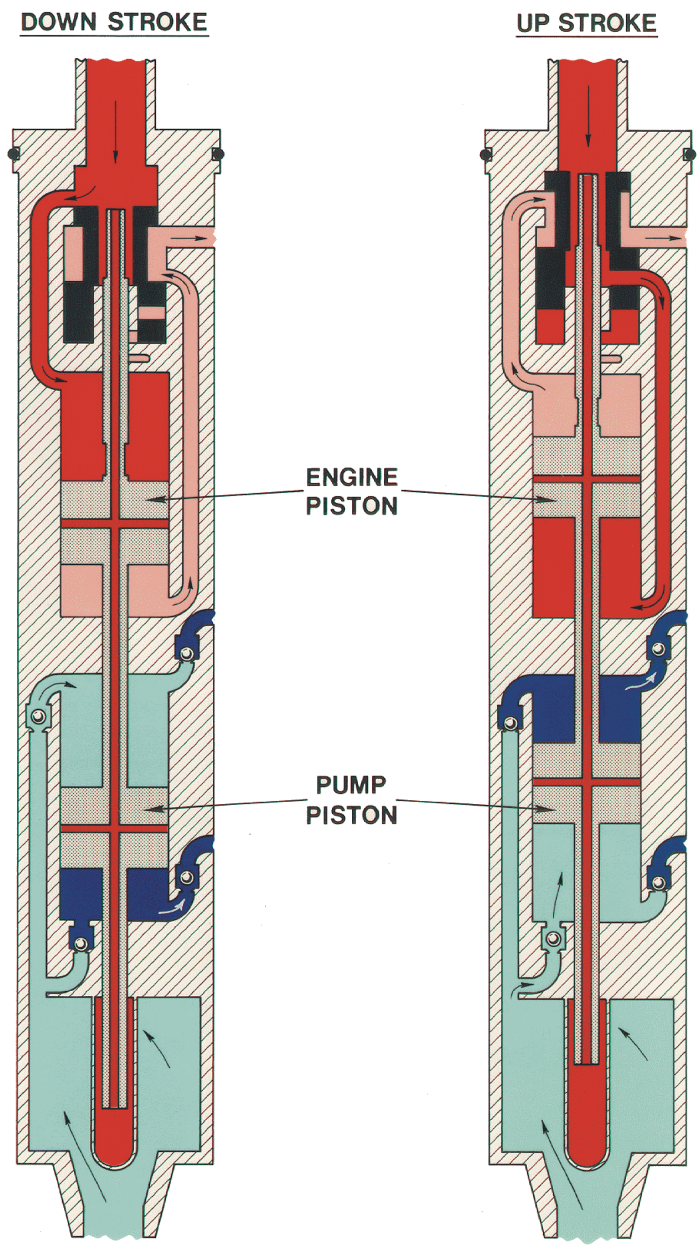
HOW THE JET PUMP WORKS



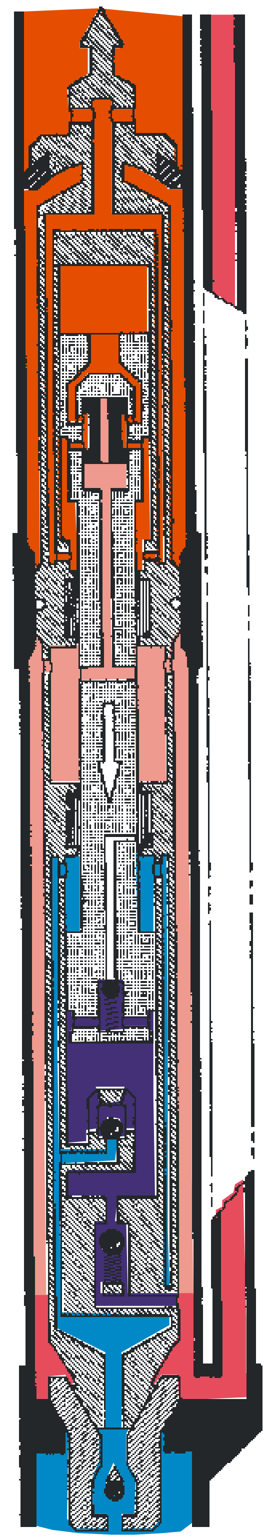
1-1/4” COILED TUBING JET PUMP

- Installs Without Pulling Tubing
- Can Be Run In Directional or Horizontally Completed Wells
- Capable of “Free” Pump Operation – Circulate In and Out Hydraulically
- Jet Pump Design Adaptable To a Wide Variety of Well Conditions and Configurations

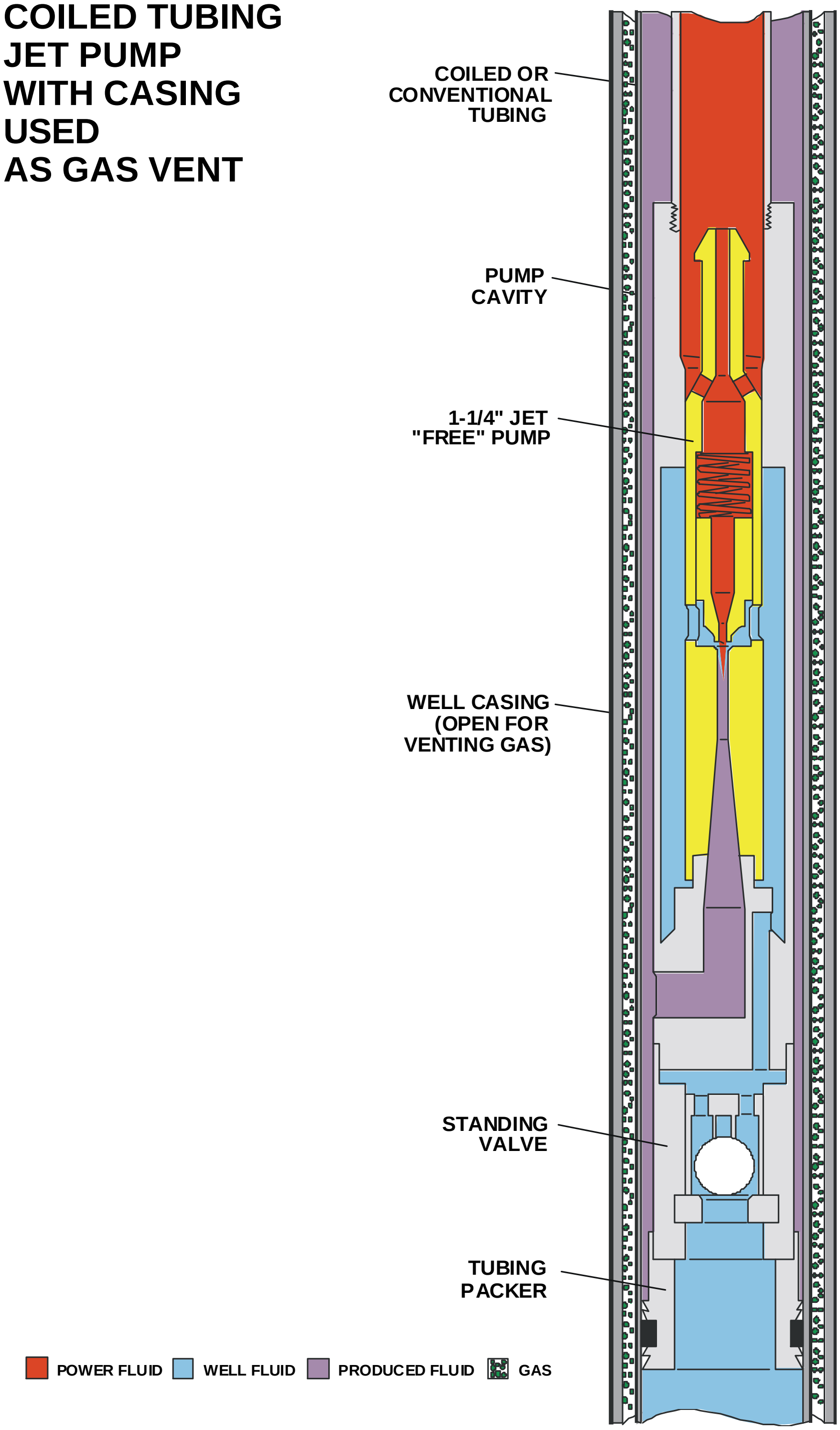
HYDRAULIC PUMP OPERATION



OILMASTER
TYPE F PUMP



COILED TUBING JET PUMP WITH CASING USED AS GAS VENT



JET PUMP SIZE DIMENSIONS

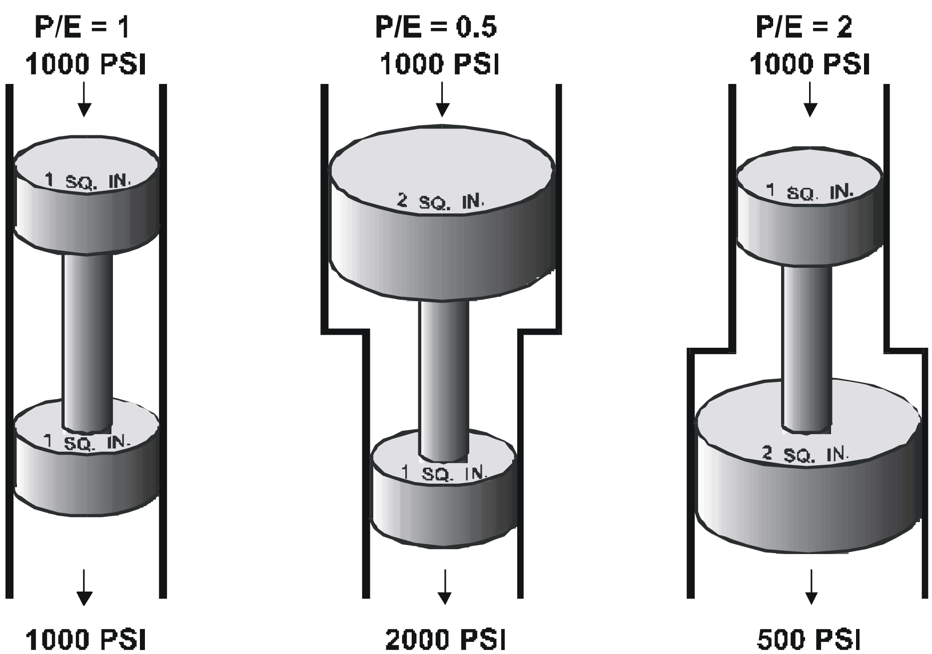
Example: Size 8 Nozzle (N) With Increasing Throat (T) Sizes

JET SIZE	N/T RATIO	NOZZLE SIZE	THROAT SIZE		AREA DIMENSIONS		
		N		T	An	At	As
8A-	A-	8	N-1	7	.0144	.0278	.0134
8A	A	8	N	8	.0144	.0359	.0216
8B	B	8	N+1	9	.0144	.0464	.0320
8C	C	8	N+2	10	.0144	.0599	.0456
8D	D	8	N+3	11	.0144	.0774	.0631
8E	E	8	N+4	12	.0144	.1000	.0856

OILMASTER HYDRAULIC PRODUCTION UNIT DATA

TUBING SIZED	UNIT MODEL NUMBER	UNIT MODEL NUMBER	PRESSURE RATIO	BALANCE PRESSURE	STROKE LENGTH	RATED SPEED	DISPLACEMENT – BBL/DAY			
							PER SPM (DISP. FACTOR)		RATED SPEED	
INCHES	FREE PUMPS	CONVT. PUMPS	P/E	PSI/1000'	INCHES	SPM	ENGINE	PUMP	ENGINE	PUMP
BALANCED UNITS										
2" NO. 2-3/8" O.D.	F201311	C201311	.71	305	22	68	4.2	3.0	286	204
	F201313	C201313	1.00	433	22	68	4.2	4.2	286	286
	F201611		.47	203	22	68	6.4	3.0	435	204
	F201613		.66	286	22	68	6.4	4.2	435	286
	FEB201613		.66	286	32	55	9.4	6.2	517	340
	FEB201616		1.00	433	32	55	9.4	9.4	517	517
2-1/2 NOM. 2-7/8" O.D.	F251611	C251611	.47	203	24	65	7.0	3.3	455	214
	F251613	C251613	.66	286	24	65	7.0	4.6	455	299
	F251616	C251616	1.00	433	24	65	7.0	7.0	455	455
	FE251613	CE251613	.66	286	34	53	10.0	6.6	530	350
	FE251616	CE251616	1.00	433	34	53	10.0	10.0	530	530
	FE252011		.30	130	36	51	16.5	4.95	843	250
	FE252013		.43	186	36	51	16.5	7.0	843	355
	FE252016		.64	277	36	51	16.5	10.6	843	540
VOLUMASTER UNITS										
2" NOM. 2-3/8" O.D.	VFR201611		./62	268	15	150	4.24	2.12	636	318
	VFR201613		.87	377	15	150	4.24	2.96	636	444
	VFR201616		1.32	587	15	150	4.24	4.49	636	674
	VFR20161613		.54	234	15	150	6.86	2.96	1029	444
	VFR20161616		.81	351	15	150	6.86	4.49	1029	674
2-1/2" NOM. 2-7/8" O.D.	VFR252015		.74	320	20	120	8.89	5.25	1067	630
	VFR252017		1.00	433	20	120	8.89	7.15	1067	857
	VFR252020		1.32	571	20	120	8.89	9.33	1067	1120
	VFR25202015		.41	179	20	120	15.16	5.25	1819	630
	VFR25202017		.56	242	20	120	15.16	7.15	1819	857
	VFR25202020		.73	316	20	120	15.16	9.33	1819	1120
V-SERIES UNITS										
2-1/2" NOM. 2-7/8" O.D.	V25-11-095		.95	411	15	206	6.66	6.31	1371	1300
	V25-11-118		1.18	511	15	225	5.33	6.31	1199	1420
	V25-21-063		.63	273	15	170	10.00	6.31	1700	1073
	V25-21-075		.75	325	15	186	8.38	6.31	1559	1174
220 SERIES										
2-1/2" NOM. 2-7/8" O.D.	548-252019		.93	403	48	72	22.35	20.17	1609	1452
	548-252017		.78	338	48	72	22.35	20.17	1609	1232
	348-252015		.57	247	48	72	22.35	20.17	1609	905
	348-252012		.40	173	48	72	22.35	20.17	1609	629
2-1/2" NOM. 2-3/8" O.D.	330-201615		.89	385	30	100	8.94	7.86	894	786
	330-201612		.63	273	30	100	8.94	5.46	894	546
	330-201611		.49	212	30	100	8.94	4.22	894	422
3" NOM. 3-1/2" O.D.	548-302419		.643	279	48	72	32.2	20.2	2321	1455
	548-302422		.914	396	48	72	32.2	28.7	2321	2067
	554-302423		.961	402	54	72	37.4	35.0	2693	2520

PISTON PUMP/ENGINE PRESSURE RELATIONSHIPS



WELL IDENTIFICATION INFORMATION

The first four data entry items are for well identification data and the date of the evaluation. Any combination of letters and numbers are allowed in the data entry fields for well identification data. These values are not used in any calculations. The **Customer** data field allows for up to 33 characters. The **Date** field allows for only numeric input. The **Field and Well** data field and the Weatherford **Location** data field each allow for up to 50 characters.

Well Completion and Pump Installation Data

1. **Perforation Depth (ft.):** Input the true vertical depth to the midpoint of the perforation interval(s). In general, this is not the measured depth since most drilled holes have some form of deviation from true vertical. Items 16 (Well Static BHP) and 17 (Well Flowing BHP) are assumed to be taken at the midpoint of the perforation interval(s).

2. **Pump Vertical Depth (ft.):** Input the true vertical depth to the location of the end of the pump bottom hole assembly.

   If Item 2, the pump vertical depth, is less than or greater than the perforation depth, then the pump intake pressure is corrected from the value for the flowing bottom hole pressure at the perforation depth to the value for the pump intake pressure at the pump setting depth. This correction does **not** include any gas effects. The correction is based on the average liquid gradient of the produced oil and water.

3. **Pump Instl: (1) parallel free, (2) casing free:** Enter the numerical value (1 or 2) that models the pump/system installation type. The program default for this field is option 2, the casing free type.

   The **parallel free system** includes one string of tubing that conducts the power fluid supply down to the pump and BHA (the **downstring**), and one string of tubing that returns the well produced fluids and the spent power fluid up a separate and parallel tubing string (the **upstring**).

   The **casing free system** includes one string of tubing for the power fluid supply (the **downstring**), and returns the well produced fluids and the spent power fluid up the casing-tubing annulus.

   The downstring I.D. size parameter is always associated with the hydraulic diameter used to conduct the power fluid to the pump and BHA.

Reverse flow or reverse circulation systems are special design cases that do not have a specific pump installation type number assigned. In reverse flow systems, power fluid goes down the casing-tubing annulus or a separate power fluid supply tubing string (i.e., the downstring) and the well produced fluids and spent power fluid return up a tubing string (i.e., the upstring). **Select the parallel free option (1) to model reverse flow systems.** If the power fluid supply is down the casing-tubing annulus, then **set the downstring tubing inside diameter equal to the casing inside diameter minus the production return tubing outside diameter.** The value obtained is the equivalent hydraulic diameter for the system. If tapered strings are involved, then input the weighted average of the hydraulic diameter (summation of each tubing size inside diameter X the length of that tubing size / total length). If a separate power fluid supply tubing string is used, then enter the inside diameter of the tubing string as the downstring tubing I.D. The upstring tubing is the inside diameter of the return tubing.

"Conventional" or "concentric" type installations are modeled using the casing free option (2). In this type of installation, there is a smaller diameter tubing string set inside and concentric to a larger diameter tubing string. **Input the I.D. of the larger tubing string as the casing I.D. in this case.** All other input, except for the surface producing GOR, is the same as a standard casing free type evaluation. The value entered for the GOR depends on the installation or completion design and the effectiveness of the venting system, if applicable.

Casing I.D. (in.): Enter the actual I.D. of the casing. The actual casing I.D. is the hydraulic diameter of the casing. The actual diameter is not the drift diameter. The actual diameter is the diameter through which the fluid flows, thus installation with iron sulfide, scale or paraffin deposits may have a diameter less than the original steel size diameter.

If there is a liner at the bottom of the well and the BHA is set into it, an equivalent weighted average diameter to represent the two casing sizes can be used. However, the friction losses in a casing return are generally quite low, and this correction is rarely significant. When there is gas in the return fluid, it is usually in solution or greatly compressed in the lower part of the well, and the effect of a smaller liner is usually insignificant. However, the return diameter when gas is present is much more critical in the upper part of the well where the gas is coming out of solution and occupying more volume. Acceleration effects can be significant here, too.

4. **Upstring Tubing I.D. (in.):** Enter the actual tubing I.D. for the return fluids. The actual tubing I.D. for all entries is the hydraulic diameter of the tubing. The actual diameter is not the drift diameter. The actual diameter is the diameter

through which the fluid flows, thus installations with iron sulfide, scale or paraffin deposits may have a diameter less than the original steel size diameter. This prompt will appear when the parallel free option is specified.

In some cases, a Jet Pump will be installed in a three-string bottom hole assembly (BHA). Usually the jet will return fluid up both return strings. To evaluate this type of problem, determine the upstring tubing I.D. that provides an equivalent friction pressure drop to the two turn strings.

5. **Downstring Tubing I.D. (in.):** Enter the actual tubing I.D. for the power fluid. The evaluation of the reverse flow case requires the input of the equivalent hydraulic diameter if the power fluid supply is via a casing-tubing annulus. Refer to the discussion on pump installation types (Item 3) concerning the specification of tubing diameters for reverse flow systems.

6. **Downstring Tubing O.D. (in.):** Enter the actual tubing O.D. Do not enter the coupling O.D. Note, this prompt will not appear when the parallel free option is specified. This value will always be associated with the power fluid supply tubing.

7. **Tubing Length (ft.):** Enter the actual measured depth of the power fluid supply tubing string including the length of the pump BHA. The tubing length entered must be greater than or equal to the vertical pump depth specified in Item 2. The value will always be greater than or equal to the true vertical pump set depth since all wells have some form of deviation from true vertical. It is equivalent to the measured depth to the bottom end of the pump BHA. Also, if the power fluid string is continuous coiled tubing, the same criteria applies.

8. **Pipe Cond. (1) new (2) avg. (3) old:** Enter the numerical value (1, 2 or 3) that represents the average pipe condition of the system. This input variable specifies the relative roughness used in friction pressure drop calculations. New pipe relative roughness is .0018, average is .0033, old is .0048. Weatherford experience has shown that the “average” piping condition value (2) works well for most applications. The program default value for the pipe condition is option (2), the average pipe condition. Note that the pipe condition specification applies the same value for roughness to all of the tubulars in the well. Different pipe surface conditions cannot be specified.

9. **Oil Gravity (API):** Enter the produced oil degree API gravity. The program default for the API oil gravity is 35 degrees. The value entered should be for the produced oil at stock tank conditions and corrected to 60 degrees Fahrenheit.

10. **Water Cut (%):** Enter the water cut as a percent value. The water cut is the volume percent that is water of the total fluid volume, consisting of oil and water, that was measured at test conditions in a 24-hour period. The test conditions may be at the pressure and temperature of the test or metering separator used to meter the oil and water or determined from the volumes reported at stock tank conditions.

11. **Water Specific Gravity:** Enter the specific gravity of the produced water relative to fresh water with a specific gravity = 1.00. The program default value for the water specific gravity is 1.05.

Producing GOR (scf/STB): Enter the gas-oil-ratio (GOR) of the produced oil in standard cubic feet of gas per barrel of oil produced at the pressure and temperature of the test or metering separator, or calculate the total gas produced per barrel of oil produced at stock tank conditions.

The importance of the accuracy of this input variable cannot be overemphasized. The value entered is a major factor in determining the throat and nozzle size required, the friction pressure drop of the return fluids, and is used to determine all of the correlation derived fluid properties. The accuracy of the GOR determines how well the program models the well performance. The GOR is the volume of gas, reported in standard cubic feet per day, per barrel of oil measured at test conditions in a 24-hour period. The program corrects the producing GOR in value to a total GOR value by estimating the solution gas remaining in the oil at the pressure and temperature of the test or metering separator.

12. **Gas SP. Gravity (air=1.):** Enter the produced gas specific gravity relative to the specific gravity of air = 1.00, (the program accepts values between 0.0 2.0). The program default for the gas specific gravity is 0.80. The presence of H_2S or CO_2 will lead to higher values. The gas gravity is a major factor used to determine correlation derived fluid properties.

13. **Separator Press (psig):** Enter the operating pressure of the test or metering separator used to meter the oil, water, and gas volumes.

In many cases a tank battery serves one well or a limited number of wells and the stock tanks are used to gauge the production of a well. If the fluids are measured at stock tank conditions then enter the operating pressure of the last treater vessel or production separator that is immediately upstream of the stock tanks. Thus, the operating pressure of the pressure vessel that dumps its oil and water into the stock tanks is the value entered as the separator pressure.

The separator pressure variable is used to correct the GOR value from the test condition to the dead oil condition found in the stock tanks and establishes the base value for the oil and water volumes for use by multi-phase flow correlations.

Note: The program default value for separator pressure is 30 psig.

Well Static BHP (psig): Enter the static or reservoir bottom hole pressure. The static BHP is the pressure the oil reservoir would build up to and stabilize at if no further production were allowed. This is the first of three values used to construct an inflow performance relationship (IPR) curve for the well. The program assumes that the well static bottom hole pressure (Item 16) and the well producing or flowing bottom hole pressure (Item 17) is determined at the midpoint of the perforation interval(s). Thus, the pressure datum is at the midpoint of the perforation interval. See the discussion concerning the perforation depth in Item 1. If the static pressure is not known, then enter a zero. Jet calculations can proceed without knowing the static bottom hole pressure. **If a value of 9 is entered, then Vogel IPR curve will not be developed.**

14. Well Flowing BHP (psig): Enter the steady state producing or flowing bottom hole pressure that corresponds to the production rate specified for the oil and water in Item 18 (Well Test Flow Rate). The IPR curve and its ability to model changes in the production rate for different producing bottom hole pressures is dependent on the accuracy of the reported rates and pressures. If the producing bottom hole pressure is not known, then enter a zero. **If a value of 0 is entered, then the Vogel IPR curve will not be developed.**

15. **Well Test Flow Rate (bpd):** Enter the total liquid flow rate of the oil and water as reported by production test on a 24 hour basis. Note that the rate is reported on a 24-hour basis. If the actual rate is not based on a 24 hour test period, then enter an estimate of what the rate would be if reported on a 24 hour basis. The multi-phase flow correlations are based on the volumes produced during a 24-hour basis. Note that the rate is reported on a 24-hour basis. If the actual rate is not based on a 24 hour test period, then enter an estimate of what the rate would be if reported on a 24 hour basis. The multi-phase flow correlations are based on the volumes produced during a 24-hour period. In addition, the program will correct the oil and water rate reported at the test conditions to the oil and water volumes that would occur at stock tank conditions. The IPR relation and the multi-phase flow correlations use the oil and water volumes calculated or reported at stock tank conditions. If the well test production rate is not known, then enter a zero. **If a value of 9 is entered, then the Vogel IPR curve will not be developed.**

Wellhead Temp. (deg F): Enter the temperature at the wellhead of the produced fluid consisting of the well produced fluids and the spent power fluid. The well temperature is used to calculate the well temperature gradient. The wellhead temperature affects the calculation of the Jet Pump discharge pressure by affecting the fluid property values calculated by the multi-phase fluid flow correlation. Changes in the estimation of the discharge pressure at the pump causes the suction rate and performance of the jet to vary. The program default value for the wellhead temperature is 100 degrees F.

16. **Bottom Hole Temp. (deg. F):** Enter the bottom hole temperature reported at the perforation depth (must be greater than the surface temperature). The default value, if the temperature is not known, is the wellhead temperature plus one-degree F for each 100 feet to the perforation depth. The bottom hole temperature affects the calculation of the Jet Pump discharge pressure by affecting the fluid property values calculated by the multi-phase flow correlations.

17. **(1) vented (2) unvented:** Enter the numerical value (1 or 2) to define whether the program's method of estimating the gas vent volumes will be used in estimating pump performance. The program default vent type for this data field is option 2, unvented.

The effectiveness of downhole gas vents is difficult to predict accurately. If option (1) vented is specified, then the program calculates the amount of free gas at each pump intake pressure. It then calculates the area ratio of the power fluid string I.D. to the casing I.D. and multiplies it times the free gas volume. This amount is assumed to go through the pump, with the remainder being vented. In a typical installation, this calculation method would allow about 80% of the free gas to be vented. This technique probably underestimates the effectiveness of gas venting in a concentric installation such as 1-1/2" tubing inside 2-7/8" tubing inside 5-1/2" casing because it uses the area ratio of the two tubing strings rather than the area ratio of the tubing string to the casing. Venting should be considered if the GOR is high or if the producing bottom hole pressure (pump intake pressure) is low. Venting will improve the performance of the pump itself, but because less gas is in the return conduit to the surface, higher pump discharge pressures may result. The overall effect of venting depends on the balance of these two factors.

Another technique concerning vented installations is a method that allows the user to override the program applied area ratio factor by specifying the unvented option and then inputting a different GOR value. The GOR will vary from the minimum value equal to the solution GOR calculated at pump intake conditions to the GOR reported at test separator conditions. The effectiveness of the gas vent can be modeled by varying the program GOR variable. This capability to override the area ratio factor is especially important when modeling an existing Jet Pump installation.

18. **Power Fld (1) oil (2) water:** Enter the numerical value (1 or 2) that corresponds to the power fluid type. The program default value for the power fluid type is option 1, for oil as the power fluid.

19. **Power Fld API/Sp. Gravity:** Enter the appropriate value for the power fluid specific gravity consistent with the power fluid type specified in Item 22. Enter the API gravity if the power fluid is an oil or the specific gravity relative to water if the power fluid is water. The program allows for the specification of power fluids that have specific gravities that differ from the specific gravity of the produced oil or water.

20. **Bubble Pt. Press. (psia):** Enter the bubble point pressure of the crude oil determined from a PVT analysis or as calculated by flash calculation procedures if the composition of the reservoir fluid is known. Enter a zero of the bubble point pressure is not known. The program will calculate an estimated value for the bubble point pressure if it is not known. The bubble point pressure is used in developing the well inflow performance relationship (IPR) curve.

Wellhead Press (psig): Enter the pressure of the produced fluids at the point that they exit the wellhead. The program default value for the pressure at the wellhead is 100 psig. This variable is very important to the performance of the Jet Pump model. The performance of a Jet Pump system is dependent on the discharge pressure required to overcome the effects of fluid friction, hydrostatic pressures due to the fluid gradient, and the wellhead or back pressure acting on the system. This value can significantly change the pump discharge pressure when gas is present because it affects the density of the upper portion of the return column.

To model new Unidraulic installations, enter a wellhead pressure that is greater than or equal to the current flowline pressure plus 40 psig. An operating pressure at least 40 psig above the flowline pressure is required for proper hydrocyclone operation.

WELL DATA SUMMARY SHEET

CUSTOMER: ____________________
FIELD & WELL: ____________________
TRICO LOCATION: ____________________
DATE: ____________________

1.	PERFORATION DEPTH	________	ft
2.	PUMP VERTICAL DEPTH	________	ft
3.	PUMP INSTALLATION - (1) PARALLEL (2) CASING	________	
4.	CASING ID	________	in
5.	UPSTRING TUBING ID	________	in
6.	DOWNSTRING TUBING ID	________	in
7.	DOWNSTRING TUBING OD	________	in
8.	TUBING LENGTH	________	ft
9.	PIPE CONDITION - (1) NEW (2) AVG. (3) OLD	________	
10.	OIL GRAVITY	________	API
11.	WATER CUT	________	%
12.	WATER SPECIFIC GRAVITY	________	
13.	PRODUCING GOR	________	scf/STB
14.	GAS SPECIFIC GRAVITY (AIR = 1.00)	________	
15.	SEPARATOR PRESSURE	________	psig
16.	STATIC BHP	________	psig
17.	FLOWING BHP	________	psig
18.	WELL TEST FLOW RATE	________	BPD
19.	WELLHEAD TEMPERATURE	________	deg F
20.	BOTTOM HOLE TEMPERATURE	________	deg F
21.	VENTED (1) UNVENTED (2)	________	
22.	POWER FLUID - (1) OIL (2) WATER	________	
23.	POWER FLUID GRAVITY (API FOR OIL, S.G. FOR WATER)	________	
24.	BUBBLEPOINT PRESSURE	________	psia
25.	WELLHEAD PRESSURE	________	psig

DESIRED PRODUCTION ____________________ BPD AT ____________ psig PRODUCING BHP

COMMENTS:
____
____

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WELL DATA SUMMARY SHEET

CUSTOMER: ____________________
FIELD & WELL: ____________________
TRICO LOCATION: ____________________
DATE: ____________________

1.	PERFORATION DEPTH	________	m
2.	PUMP VERTICAL DEPTH	________	m
3.	PUMP INSTALLATION - (1) PARALLEL (2) CASING	________	
4.	CASING ID	________	mm
5.	UPSTRING TUBING ID	________	mm
6.	DOWNSTRING TUBING ID	________	mm
7.	DOWNSTRING TUBING OD	________	mm
8.	TUBING LENGTH	________	m
9.	PIPE CONDITION - (1) NEW (2) AVG. (3) OLD	________	
10.	OIL GRAVITY	________	API
11.	WATER CUT	________	%
12.	WATER SPECIFIC GRAVITY	________	
13.	PRODUCING GOR	________	m^3/m^3
14.	GAS SPECIFIC GRAVITY (AIR = 1.00)	________	
15.	SEPARATOR PRESSURE	________	kPa
16.	STATIC BHP	________	MPa
17.	FLOWING BHP	________	MPa
18.	WELL TEST FLOW RATE	________	m^3/D
19.	WELLHEAD TEMPERATURE	________	deg C
20.	BOTTOM HOLE TEMPERATURE	________	deg C
21.	VENTED (1) UNVENTED (2)	________	
22.	POWER FLUID - (1) OIL (2) WATER	________	
23.	POWER FLUID GRAVITY (API FOR OIL, S.G. FOR WATER)	________	
24.	BUBBLEPOINT PRESSURE	________	MPa
25.	WELLHEAD PRESSURE	________	kPa

DESIRED PRODUCTION ____________________ m^3/D AT ________________ MPa PRODUCING BHP

COMMENTS:
____
____

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WELL DATA SUMMARY

Customer	:	JET PUMP PROGRAM VERSION 4.1	Date	: 02/17/95
Field & Well	:	TEST WELL		
Location	:	SAN MARCOS, TEXAS	Run ID	: 113351-02

1. Perforation Depth	(ft) :	9000.0	13.Producing GOR	(scf/STB) :	100.0
2. Pump Vertical Depth	(ft) :	9000.0	14.Gas Sp. Gravity	(air=1.) :	0.800
3. Pump Instl (1) parallel free			15.Separator Press	(psig) :	30.0
(2) casing free	:	2	16.Well Static BHP	(psig) :	0.0
4. Casing ID	(in) :	4.892	17.Well Flowing BHP	(psig) :	0.0
5. Upstring ID	(in) :	N/A	18.Well Test Flow Rate(bpd)	:	0.0
6. Downstring Tubing ID	(in) :	2.441	19.Well Head Temp	(deg. F) :	120.0
7. Downstring Tubing OD	(in) :	2.875	20.Bottom Hole Temp	(deg. F) :	205.0
8. Tubing Length	(ft) :	9100.0	21.(1)vented (2)unvented	:	2
9. Pipe Cond (1)new(2)avg(3)old	:	2	22.Power Fld (1)oil (2)water	:	1
10.Oil Gravity	(API) :	30.000	23.Power Fld API/Sp. Gravity	:	30.000
11.Water Cut	(%) :	19.60	24.Bubble Point Press (psia)	:	472.5
12.Water Specific Gravity	:	1.030	25.Welll Head Press	:	110.3

Oilmaster 7X Jet Pump Performance Summary for user specified target
Production Rate of 250. BPD at 500. PSIG Pump Intake pressure

FLOW RATE - BPD

PIP-PSI	WELL	CAV.	PF=2750.PSI		PF=3250.PSI		PF=3750.PSI		PF=4250.PSI	
			QS	QN	QS	QN	QS	QN	QS	QN
750.	0.	344.	189.	1036.	288.	1084.	385.	1129.	478.	1172.
700.	0.	332.	174.	1042.	278.	1089.	377.	1134.	467.	1177.
650.	0.	320.	165.	1047.	269.	1094.	368.	1138.	459.	1181.
600.	0.	308.	156.	1052.	261.	1098.	358.	1143.	448.	1185.
550.	0.	295.	147.	1057.	252.	1103.	350.	1147.	440.	1189.
500.	0.	278.	138.	1062.	239.	1108.	336.	1151.	425.	1194.
450.	0.	258.	126.	1066.	225.	1112.	319.	1156.	408.	1198.
400.	0.	237.	114.	1071.	211.	1117.	300.	1160.	385.	1202.
350.	0.	215.	102.	1076.	193.	1121.	280.	1164.	361.	1206.
300.	0.	192.	91.	1081.	176.	1126.	258.	1169.	332.	1210.
250.	0.	170.	78.	1085.	157.	1130.	232.	1173.	301.	1214.
200.	0.	146.	65.	1090.	139.	1135.	206.	1177.	265.	1218.
150.	0.	119.	53.	1094.	115.	1139.	170.	1182.	219.	1223.
100.	0.	89.	38.	1099.	84.	1143.	121.	1186.	151.	1227.
50.	0.	54.	22.	1104.	43.	1148.	58.	1190.	69.	1231.
0.	0.	0.	0.	1108.	0.	1152.	0.	1194.	0.	1235.

103.HP

PREPARED BY : DATE :02/17/95

THE EVALUATION IS BASED ON THE WELL DATA SPECIFIED BY:____________________

WELL DATA SUMMARY

Customer : JET PUMP PROGRAM VERSION 4.1 Date : 02/17/95

1. Perforation Depth (ft) : 9000.0
2. Pump Vertical Depth (ft) : 9000.0
3. Pump Instl (1) parallel free
   (2) casing free : 2
4. Casing ID (in) : 4.892
5. Upstring ID (in) : N/A
6. Downstring Tubing ID (in) : 2.441
7. Downstring Tubing OD (in) : 2.875
8. Tubing Length (ft) : 9100.0
9. Pipe Cond (1)new(2)avg(3)old : 2
10. Oil Gravity (API) : 30.000
11. Water Cut (%) : 19.60
12. Water Specific Gravity : 1.030
13. Producing GOR (scf/STB) : 100.0
14. Gas Sp. Gravity (air=1.) : 0.800
15. Separator Press (psig) : 30.0
16. Well Static BHP (psig) : 1000.0
17. Well Flowing BHP (psig) : 500.0
18. Well Test Flow Rate(bpd) : 250.0
19. Well Head Temp (deg. F) : 120.0
20. Bottom Hole Temp (deg. F) : 205.0
21. (1)vented (2)unvented : 2
22. Power Fld (1)oil (2)water : 1
23. Power Fld API/Sp. Gravity : 30.000
24. Bubble Point Press (psia) : 472.5
25. Welll Head Press : 110.3

Oilmaster 7X Jet Pump Performance Summary for user specified target
Production Rate of 250. BPD at 500. PSIG Pump Intake pressure

FLOW RATE – BPD

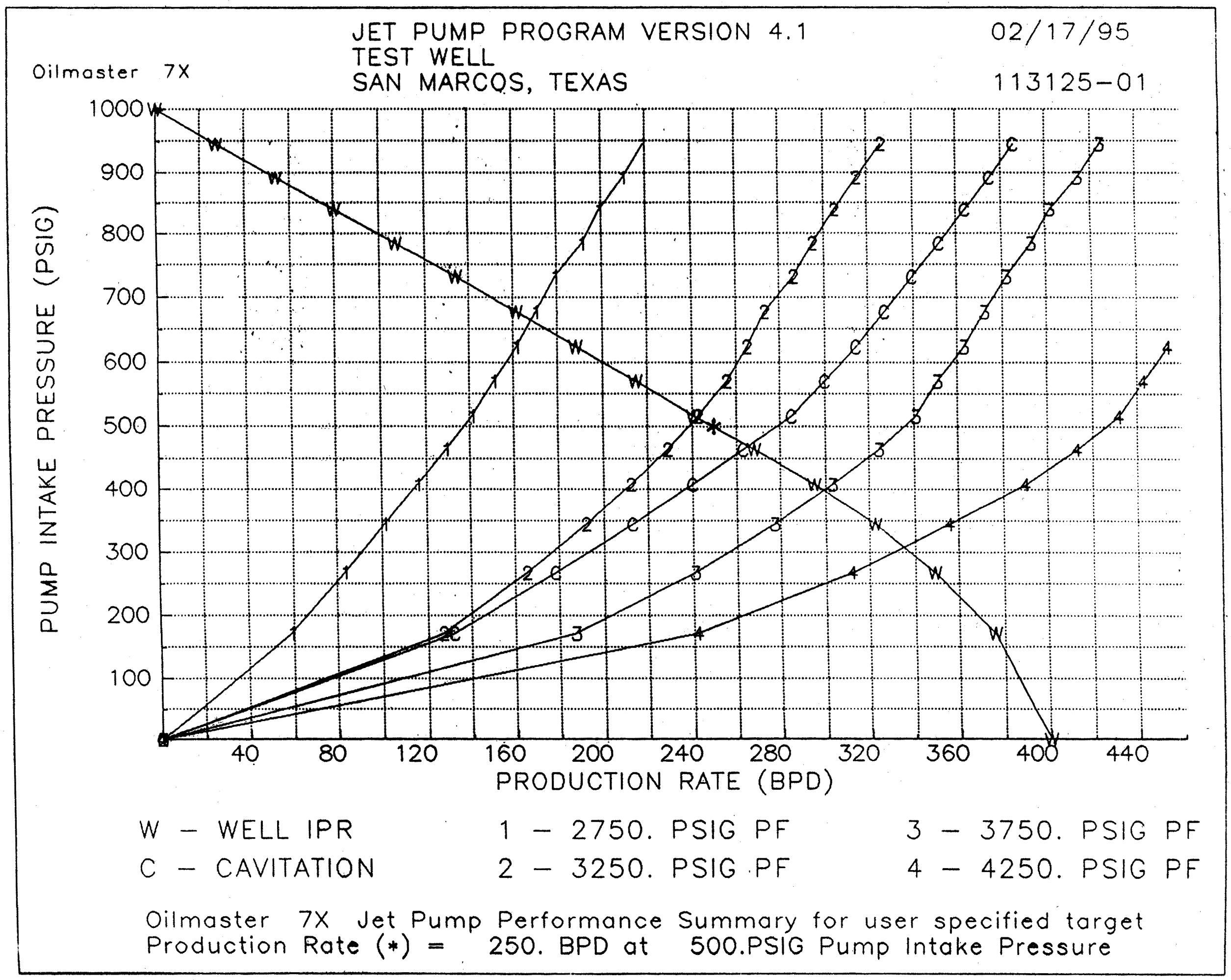
PIP-PSI	WELL	CAV.	PF=2750.PSI		PF=3250.PSI		PF=3750.PSI		PF=4250.PSI	
			QS	QN	QS	QN	QS	QN	QS	QN
1000.	0.	397.	236.	1012.	335.	1061.	434.	1106.	526.	1150.
946.	27.	386.	219.	1018.	326.	1066.	424.	1112.	517.	1155.
893.	54.	375.	210.	1024.	315.	1071.	414.	1117.	505.	1160.
839.	80.	364.	199.	1029.	305.	1076.	402.	1121.	496.	1165.
785.	107.	352.	191.	1034.	295.	1081.	393.	1126.	484.	1169.
732.	134.	340.	179.	1039.	286.	1086.	382.	1131.	473.	1174.
678.	161.	327.	170.	1045.	272.	1091.	372.	1136.	464.	1178.
624.	188.	314.	161.	1050.	265.	1096.	363.	1141.	454.	1183.
571.	215.	300.	151.	1055.	256.	1101.	351.	1145.	443.	1188.
517.	241.	285.	141.	1060.	243.	1106.	341.	1150.	432.	1192.
464.	268.	263.	129.	1065.	229.	1111.	324.	1155.	413.	1197.
408.	295.	240.	116.	1070.	212.	1116.	303.	1160.	390.	1201.
344.	322.	213.	101.	1076.	192.	1122.	277.	1165.	356.	1207.
269.	349.	178.	83.	1083.	165.	1128.	241.	1171.	213.	1213.
172.	376.	132.	59.	1092.	127.	1137.	187.	1180.	242.	1221.
0.	400.	0.	0.	1108.	0.	1152.	0.	1194.	0.	1235.

MAX. POWER REQUIRED : 60.HP 73.HP 88.HP 103.HP

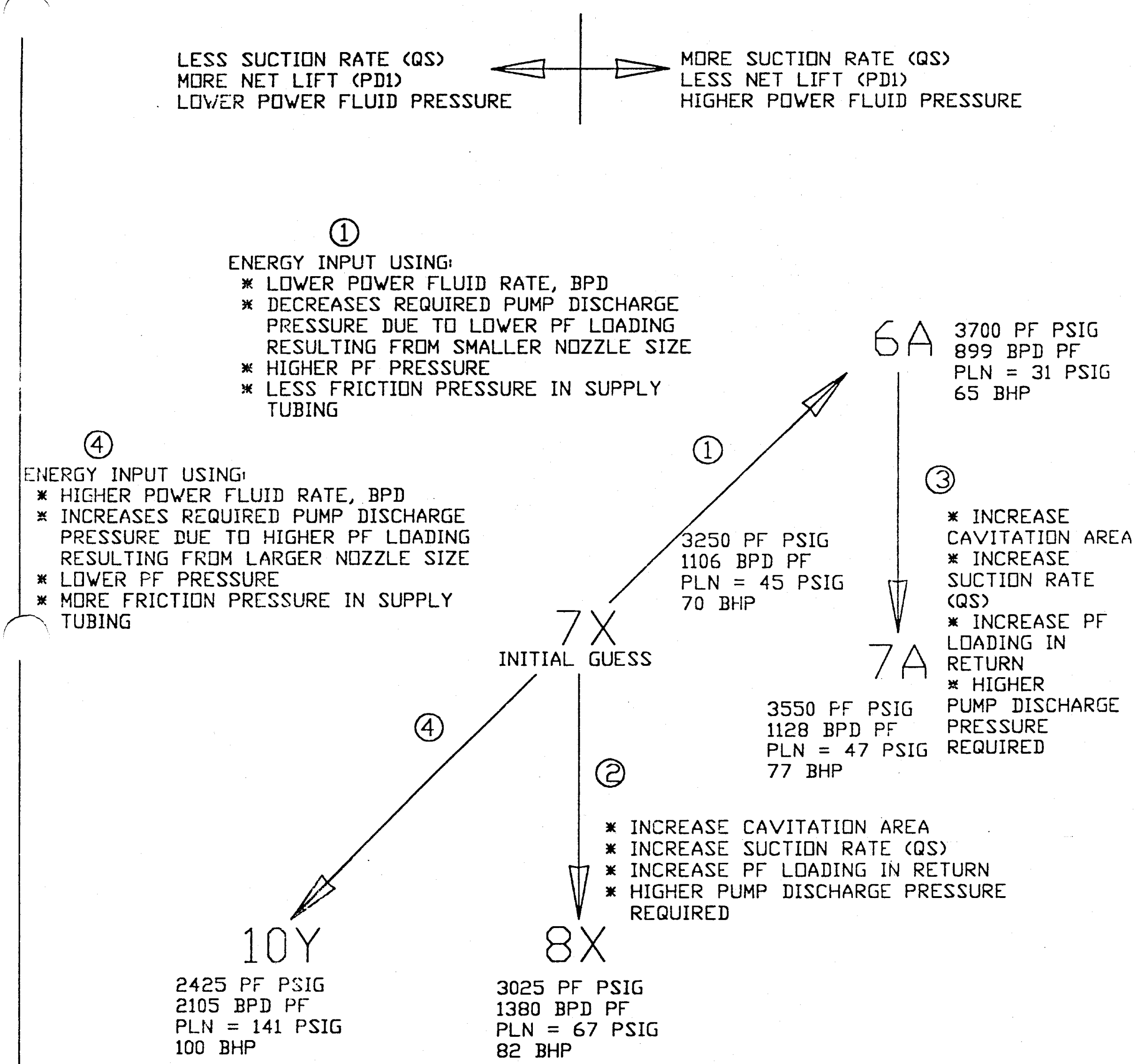
PREPARED BY : ____________________ DATE: 02/17/95

THE EVALUATION IS BASED ON THE WELL DATA SPECIFIED

JET PUMP PERFORMANCE CHART



TESTWELL.JPD SIZING EXAMPLE



JET PUMP SIZING CRITEREIA:

* THROAT ANNULAR AREA > MINIMUM CAVITATION AREA
* MAXIMIZE EFFICIENCY BY SELECTING THE MOST EFFICIENT AREA RATIO
* PROVIDE FOR OPERATIONAL FLEXABILITY
* SPECIFY THE SMALLEST PRACTICAL NOZZLE SIZE TO MINIMIZE POWER FLUID LOADING AND THE REQUIRED PUMP DISCHARGE PRESSURE

PERFORMANCE CALCULATION INTERPRETATION

To interpret the performance summary data, fins the operating pump intake pressure under “PIP-PSI.” The number to the right, under “WELL,” is the producing ability of the well at that PIP. If “0” appears, no information given to calculate Vogel curve.

The third column to the right, “CAV,’ is the maximum volume of fluid capable of passing through the throat annulus of this combination of the throat and nozzle (9A, etc.). Do not exceed the operating pressure required to produce this volume, or throat destruction could occur.

The column labeled “QS” predicts the producing ability of the given combination at a given pump intake pressure and injection pressure rating. If “9999” appears, data above calculations reflect flowing condition at stated PIP.

The column labeled “QN” to the immediate right of the producing rate is the amount of power fluid required at this particular operating pressure and PIP to obtain desired production.

All information is for the jet combination shown at the top of the summary. This is usually determined as the best combination for this application; however, combinations can be changed, if required, to fit a particular need (triplex size).

The horsepower figure at the bottom of the page represents the amount it would require to pull the well to zero (0) PSI. To find horsepower needed, use the following formula.

Input and Hydraulic horsepower can be calculated from the following equations:

HYDRAULIC HORSEPOWER = <u>OPERATION PRESSURE (PSI) x POWER FLUID RATE BPD / 58,800</u>

$$\text{BRAKE HORSEPOWER} = \frac{\text{HYDRAULIC HORSEPOWER}}{.90}$$

HYDRAULIC RECIPROCATING PUMP DESIGN SUMMARY NO. 2

********************** WELL AND COMPANY IDENTIFICATION **********************************

1. COMPANY NAME ; SUPER H
2. FIELD NAME : SYSTE3M 1
3. LEASE NAME : PISTON PUMP
4. WELL IDENTIFICATION/NUMBER : 1
5. COMPANY REPRESENTATIVE'S NAME : CAT
6. WEATHERFORD LOCATION : HOUSTON
7. EVALUATION DATE : 10-28-97
8. EVALUATION BY : JAF

********************* INPUT WELL TEST DATA SUMMARY **************************************

1. SPECIFIC GRAVITY OF THE PRODUCED GAS : .8
2. PRODUCED OIL API GRAVITY : 30
3. WATER CUT OF THE PRODUCED FLUIDS, % : 19.6
4. SPECIFIC GRAVITY OF THE PRODUCED WATER (FRESH WATER = 1.0) : 1.03
5. GAS TO OIL RATIO (GOR) AT TEST SEPARATOR CONDITIONS, SCF/STB : 100
6. TOTAL FLUID PRODUCTION RATE AT TEST SEPARATOR CONDITIONS, BBL/DAY : 250
7. OPERATING PRESSURE OF THE TEST OR METERING SEPARATOR, PSIG : 30
8. OPERATING TEMPERATURE OF THE TEST OR METERING SEPARATOR, DEG. F : 120
9. FLOWING BOTTOM HOLE PRESSURE AT THE PRESSURE DATUM OF THE PERFORATION INTERVAL, PSIG : 500
10. STATIC BOTTOM HOLE PRESSURE (RESERVOIR PRESSURE), PSIG : 1000
11. BOTTOM HOLE TEMPERATURE AT THE PERFORATIONS, DEG. F : 205
12. WELLHEAD BACK PRESSURE OF THE OIL + WATER + GAS + POWER FLUID IN THE CASING/TUBING ANNULUS (PSIG) : 110.3
13. WELLHEAD TEMPERATURE OF THE OIL + WATER + GAS + POWER FLUID IN THE CASING TUBING ANNULUS (DEG. F) : 120
14. BUBBLE POINT PRESSURE OF THE OIL, PSIG : 527.11

********************* WELL COMPLETION AND PUMP INSTALLATION DATA SUMMARY ********************

1. VERTICAL DEPTH TO THE FLUID INTAKE OF THE PUMP, FT. : 9000
2. VERTICAL DEPTH TO THE PRESSURE DATUM OF THE PERFORATION INTERVAL(S), FT. : 9000
3. VERTICAL DEPTH AT WHICH THE WELL FLUIDS ENTER THE END OF THE TUBING OR BOTTOM HOLE ASSEMBLY BELOW THE FLUID INTAKE OF THE PUMP, FT. : 9000
4. POWER FLUID TYPE: (1) OIL OR (2) WATER : 1
5. POWER FLUID SPECIFIC GRAVITY: (INPUT API GRAVITY FOR OIL, SPECIFIC GRAVITY FOR WATER) : 30
6. OPERATING PRESSURE OF THE POWER FLUID RESERVOIR VESSEL OR THE EQUIVALENT HEAD, IN PSI, OF THE POWER FLUID SETTLING (WASH) TANK, PSIG : 50
7. OPERATING TEMPERATURE OF THE POWER FLUID RESERVOIR VESSEL OR OF THE POWER FLUID SETTLING (WASH) TANK, DEG. F : 100
8. CASING STRING INSIDE DIAMETER, IN. : 4.892
9. POWER FLUID SUPPLY TUBING INSIDE DIAMETER, IN. : 2.441
10. POWER FLUID SUPPLY TUBING OUTSIDE DIAMETER, IN. : 2.875
11. CASING STRING INSIDE DIAMETER PIPE CONDITION : (1) NEW, (2) AVERAGE, OR (3) OLD = 2 (.0018 IN. ABSOLUTE ROUGHNESS)

*********** WELL COMPLETION AND PUMP INSTALLATION DATA SUMMARY (CONTINUED) ***************

12. POWER FLUID SUPPLY TUBING LENGTH, FT. = 9100
13. POWER FLUID SUPPLY TUBING INSIDE DIAMETER PIPE CONDITION : (1) NEW, (2) AVERAGE, OR (3) OLD = 2 (.0018 IN. ABSOLUTE ROUGHNESS)
14. POWER FLUID SUPPLY TUBING OUTSIDE DIAMETER PIPE CONDITION : (1) NEW, (2) AVERAGE, OR (3) OLD = 2 (.0033 IN. ABSOLUTE ROUGHNESS)

********************************* PUMP DESIGN PARAMETERS *********************************

1. ENGINE END MECHANICAL EFFICIENCY PERCENT (%) (70% <= EFF <= 95%) : 95%
2. PUMP END MECHANICAL EFFICIENCY PERCENT (%) (70% <= EFF <= 95%) : 92%
3. DESIGN PERCENT OF MAXIMUM RATED SPEED (%) (25% <= DPRS <= 100%) : 100%

******************************* PUMP PERFORMANCE SUMMARY ************************************

SYSTEM TYPE : (1) STANDARD CASING FREE PUMP, OPEN POWER FLUID
HYDRAULIC PRODUCTION UNIT TYPE : (1) OILMASTER F/FE/FEB, BALANCED
POWER FLUID TYPE : OIL
HYDRAULIC PRODUCTION UNIT MODEL NUMBER : FE251613
TOTAL FLUID PRODUCTION RATE IN BBL/DAY : 250 BBL/DAY
STROKE RATE OF THE PUMP : 45.2 STROKES/MIN
PERCENT OF THE RATED SPEED FOR THE PUMP : 85.4%
VOLUMETRIC EFFICIENCY OF THE PRODUCED FLUIDS AT THE PUMP SUCTION CONDITIONS FOR PRESSURE AND TEMPERATURE : 88.8%
CALCULATED PUMP END HYDRAULIC EFFICIENCY : 83.6%
ENGINE END MECHANICAL EFFICIENCY PERCENT : 95%
PUMP END MECHANICAL EFFICIENCY PERCENT : 92%
POWER FLUID RATE REQUIRED, IN STOCK TANK BBL/DAY : 446.9 BBL/DAY
POWER FLUID PRESSURE REQUIRED AT THE SURFACE : 2308.8 PSIG
REQUIRED SURFACE HORSEPOWER (AT 90% EFFICIENCY) : 19.4 HP
SUCTION PRESSURE OF THE PUMP AT 9000 FEET : 500 PSIG
VERTICAL MULTI-PHASE FLOW PUMP DISCHARGE PRESSURE : 3406.4 PSIG

ARTIFICIAL LIFT SYSTEMS COMPARISON

	Sucker Rod	ESP	Hydraulic Reciprocating Pump	Hydraulic Jet Pump
High viscosity fluid handling capability	**Good** for <200 cp fluids and low rates (400 BFPD). Rod fall problem for high rates. Higher rates may require diluent to lower viscosity.	**Fair.** Limited to about 200 cp. Increases horsepower and reduces head.	**Good**. >8° API production with <500 cp possible. Power fluids can be used to dilute low-gravity production.	**Good/excellent.** Production with up to 800 cp possible. Power oil of >24° API and <50 cp or water power fluid reduces friction losses.
High volume lift capabilities	**Fair.** Restricted to shallow depths using large plungers. Maximum rate about 4000 BFPD from 1000 ft. and 1000 BFPD from 5000 ft. with correct tubulars.	**Excellent.** Limited by needed horsepower and can be restricted by casing size. In 5.5 inch casing can produce 4000 BFPD from 4000 ft. with 240 horsepower. In shallow wells with large casing can produce 95,000+ BFPD.	**Good.** Not so depth limited. Can lift large volumes from great depths. Typically 3000 BFPD from 4000 ft. and 1000 BFPD from 10,000 ft. with 3500 psi system.	**Excellent**. Can handle volumes to 15,000 BFPD and higher with adequate flowing bottom hole pressure, tubular size and horsepower.
Low volume lift capabilities	**Excellent.** Most commonly used method for wells producing <100 BFPD.	**Generally poor.** Lower efficiencies and high operating costs for <400 BFPD.	**Fair.** Not as good as rod pumping. Typically 100 to 300 BFPD from 4000 to 10,000 ft. >250 BFPD from 12,000 ft. possible.	**Fair.** >200 BFPD from 4000 ft. <20 BFPD from 4000 ft. with coiled tubing.
Prime mover flexibility	**Good.** Both engines or motors can be used easily (motors more reliable and flexible).	**Fair.** Requires a good power source without spikes or interruptions. Higher voltages can reduce I^2R losses.	**Excellent.** Prime mover can be electric motor, gas or diesel-fired engines or motors.	Same as hydraulic reciprocating pump.
Surveillance	**Good.** Can be easily analyzed based on well test, fluid levels, etc. Analysis improved by use of dynamometers and computers.	**Fair.** Electrical checks but special equipment needed otherwise.	**Good/fair.** Downhole pump performance can be analyzed from surface power fluid rate and pressure, speed and producing rate. Bottom hole pressure obtained with free pumps.	Same as hydraulic reciprocating pump.
Offshore application	**Poor.** Must design for unit size, weight and pulling unit space. Most wells are deviated and typically produce sand.	**Good.** Must provide electrical power and service pulling unit.	**Fair.** Feasible operation in highly deviated wells. Requires deck space for treating tanks and pumps. Water power fluid can be used. Power oil a fire/safety problem.	**Good.** Produced water or seawater may be used as power fluid with well site type system or power fluid separation before production treating system.

ARTIFICIAL LIFT SYSTEMS COMPARISON

	Sucker Rod	ESP	Hydraulic Reciprocating Pump	Hydraulic Jet Pump
Capital cost	**Low to moderate.** Increases with depth and larger units.	**Relatively low** if commercial electric power available. Costs increase with horsepower.	**Varies** but often competitive with rod pumps. Multi-well installations reduce cost per well but are more complicated.	**Competitive** with sucker rod. Cost increases with higher horsepower.
Downhole equipment	Reasonably good rod design and selection practices needed as well as good selection, operating and repair practices for rods and pumps.	Requires proper cable in addition to motor, pumps, seals, etc. Good design plus good operating practices essential.	Proper pump sizing and operating practices essential. Required power fluid conductor. Free pump and closed power fluid option.	Requires computer design programs for sizing. Tolerant of moderate solids in power fluid. No moving parts in pump. Long service life. Simple repair procedures. Field repairable.
Efficiency (output hydr. horsepower divided by input hydr. Horsepower)	**Excellent** total system efficiency. Full pump fillage efficiency typically about 50 to 60% - feasible if well is not overpumped.	**Good** for high rate wells but decreases significantly for <1000 BFPD. Typically total system efficiency is about 50% for high rate wells but for <1000 BFPD efficiency typically is <40%.	**Fair to good.** Not as good as rod pumping owing to GLR, friction and pump wear. Efficiencies range from 30% to 40% with GLR> 100. May be higher with lower GLR.	**Fair to poor.** Maximum efficiency only 30%. Heavily influenced by power fluid plus production gradient. Typical operating efficiencies of 10% to 20%.
Flexibility	**Good.** Can alter stroke speed and length, plunger size (requires gang/crew to change) and run time to control production rate.	**Poor.** Pumps usually run at a fixed speed. Requires careful sizing. VSD gives more flexibility but added cost. Time cycling normally avoided. Must size pump properly.	**Good/excellent.** Can vary power fluid rate and speed of downhole pump. Numerous pump sizes and pump/engine ratios adapt to production and depth needs.	**Good to excellent**. Power fluid rate and pressure adjusts the production rate and lift capacity. Selection of throat and nozzle sizes extend range of volume and capacity.
Miscellaneous problems	Stuffing box leakage may be messy and a potential hazard. Anti-pollution stuffing boxes are available.	Requires a highly reliable electric power system. Method sensitive to rate changes.	Power fluid solids control essential. Need 15 ppm of 15-µm particle size max. to limit engine wear. Must add surfactant to a water power fluid for lubricity. Triplex plunger leakage control required.	More tolerant of power fluid solids. 200 ppm of 25-µm particles acceptable. Diluents may be added if required. Power water (fresh, produced or seawater) acceptable.

ARTIFICIAL LIFT SYSTEMS COMPARISON

	Sucker Rod	ESP	Hydraulic Reciprocating Pump	Hydraulic Jet Pump
Casing size limits (restricts tubing size)	Problems only in high rate wells requiring large plunger pumps. Small casing sizes (4.5 and 5.5 in.) may limit free gas separation.	Casing size will limit use of large motors and pumps. Avoid 4.5 inch casing and smaller. Reduced performance inside 5.5 inch casing depending on depth and rate.	Larger casing required for parallel free or closed systems.	Larger casing may be required if dual strings run.
Depth limits	**Good in straight** holes. Rods or structure may limit rate at depth. Effectively, about 500 BFPD at 7500 ft. and 150 BFPD at 15,000 ft.	**Usually limited** to motor horsepower or temperature. Practical depth about 10,000 ft.	**Excellent**. Limited by power fluid pressure (5000 psi) or horsepower. Low-volume/high-lift head pumps operating at depths to 17,000 ft.	**Excellent**. Similar limits as reciprocating pump. Practica depth of 20,000 ft.
Intake capabilities	**Excellent.** <25 psig feasible (but more pulls required) provided adequate displacement and gas venting. Typically about 50 to 100 psig.	**Fair.** If little free gas (i.e. >250 psig pump intake pressure). **Poor** if pump must handle >5% free gas.	**Fair.** Not as good as rod pumping. Intake pressure <100 psig usually results in frequent pump repairs. Free gas reduces efficiency and service life.	**Poor to fair**. >350 psig to 5000 ft. with low GLR. Typic design target is 20% submergence.
Corrosion/ scale handling ability	**Good to excellent.** Batch treating inhibitor down annulus used frequently for both corrosion and scale control.	**Fair.** Batch treating inhibitor only to intake unless shroud is used.	**Good/excellent.** Batch or continuous treating inhibition can be circulated with power fluid for effective control.	**Good/excellent**. Inhibitor with power fluid mixes with produced fluid at entry of jet pump throat.
Paraffin handling capability	**Fair/good**. Hot water/oil treating and/or use of scrapers possible but they increase operating problems and costs.	**Fair.** Hot water/oil treatments, mechanical cutting and batch inhibition possible.	**Good/excellent**. Circulate heat to downhole pump to minimize buildup. Mechanical cutting and inhibition possible. Soluble plugs available. “Free” pumps can be surfaced on a schedule.	Same as hydraulic reciprocating pump.

ARTIFICIAL LIFT SYSTEMS COMPARISON

	Sucker Rod	ESP	Hydraulic Reciprocating Pump	Hydraulic Jet Pump
Gas handling ability	**Good** if can vent and use natural gas anchor with properly designed pump. **Poor** if must pump >50% free gas.	**Poor** for free gas (i.e. >5% through pump). Rotary gas separators helpful if solids not produced.	**Good/fair.** Concentric fixed pump or parallel free permits gas venting with suitable downhole gas separator below pump intake. Casing free pump limited to low GLR's.	Similar to hydraulic reciprocating pump. Large amount of free gas reduces efficiency but helps lift. Vent free gas if possible. Use a gas anchor.
Solids/sand Handling ability	**Poor/fair** for low viscosity (<10 cp) production. Improved performance for high viscosity (>200 cp) cases. May be able to handle up to 0.l1% sand with special pumps.	**Poor**. Requires <200 ppm solids. Improved wear resistant materials available at premium cost.	**Poor**. Requires <15 ppm solids power fluids for good run life. Also, produced fluids must have low solids (<200 ppm of 15 particles) for reasonable life. Use fresh water injection for salt buildup problems.	**Fair/good**. Jet pumps are operating with 3% sand in produced fluid. Power fluid to jet pump can tolerate 200 ppm of 25 particle size. Fresh water treatment for salt buildup possible.
Slim hole completions (2-7/8 in. production casing string)	**Feasible** for low rates (<100 BFPD) and low GOR (<250). Typically are used with 1.5 inch nominal tubing.	**No known installations.**	**Possible** but may have high friction losses or gas problems. Suitable for low rates and low GLR's.	**Excellent application for coiled tubing jet pump.** Standard pump has same limitations as hydraulic reciprocating pump.
Crooked/ deviated holes	**Fair.** Increased load and wear problems. High-angle deviated holes (>70°) and horizontal wells are being produced. Some success in pumping 15°/100 ft. using rod guides.	**Good.** Few problems. Limited experience in horizontal wells. Requires long radius wellbore bends to get through.	**Excellent.** If tubing can be run in the well, pump normally will pass through the tubing. Free pump retrieved without pulling tubing. Feasible operation in horizontal wells.	**Excellent**. Short jet pump can pass through doglegs up to 24°/100 ft. in 2 inch nominal tubing. Same conditions as hydraulic reciprocating pumps.
Temperature limitation	**Excellent.** Currently used in geothermal operations (550° F).	Has been limited to <250°F for standard and <325°F with special motors and cable. Recent development of specialized equipment allows geothermal applications to 500+ °F.	**Excellent**. Standard materials to 300+ °F and 500+ °F feasible with special materials.	**Excellent**. Possible to operate to 500+ °F with special materials.

ARTIFICIAL LIFT SYSTEMS COMPARISON

	Sucker Rod	ESP	Hydraulic Reciprocating Pump	Hydraulic Jet Pump
Operating costs	**Very low** for shallow to medium depth (<7500 ft.) land locations with low production (<400 BFPD)	**Varies.** If horsepower is high, energy costs are high. High pulling costs result from short run life. Often repair costs are high.	**Often higher than rod pumps** even for free systems. Short run life due to well problems increases total operating costs.	**Higher power cost** owing to horsepower requirements. Low pump maintenance cost typical with properly sized throat and nozzle.
Reliability	**Excellent.** Run time efficiency >95% if good operating practices are followed and if corrosion, wax, asphaltenes, solids, deviations, etc. are controlled.	**Varies**. Excellent for ideal lift cases. Poor for problem areas. Very sensitive to operating temperatures and electrical malfunctions.	**Good** with correctly designed and operated system. Problems of changing well conditions reduce downhole pump reliability. Frequent downtime results from operational problems.	**Good** with proper throat and nozzle sizing for the operating conditions. Must avoid operating in cavitation range of jet pump throat – related to pump intake pressure. More problems with surface equipment if pressures >4000 psig.
Salvage value	**Excellent.** Easily moved and good market for used equipment.	**Fair.** Some trade-in value. Poor open market value.	**Fair** market for triplex pumps. **Good value** for wellsite system that can be moved easily.	**Good.** Easily moved. Some trade-in value. **Fair** market for triplex pump.
System (total)	**Straightforward** and basic procedures to design, install and operate following API specifications and recommended practices. Each well is an individual system.	**Fairly simple to design** but requires good rate data. System not forgiving. Requires excellent operating practices. Follow API recommended practices in design, testing and operation. Typically each well is an individual producer using a common electric system.	**Simple manual or computer design** typically used. Free pump easily retrieved for servicing. Individual well unit very flexible. Requires attention. Central plant more complex. Usually results in test and treatment problems.	**Computer design program** typically used for design. Basic operating procedures needed for downhole pump and wellsite unit. Free pump easily retrieved for onsite repair or replacement. With poor well data, downhole jet often requires trial and error to arrive at optimum jet.
Usage/ outlook	**Excellent.** Used on about 85% of U.S. artificial lift wells. The normal standard artificial lift method.	An **excellent high rate** artificial lift system. Best suited for <200° F and >1000 BFPD rates. Most often used on high water cut wells. Used on about 4% of U.S. lifted wells.	Often used as a default artificial lift well system. Flexible operation. Wide rate range. Suitable for relatively deep, high volume, high temperature, deviated oil wells. Used on <2% of U.S. lifted wells.	**Good** for higher volume wells requiring flexible operation. System will tolerate wide depth ranges, high temperatures, corrosive fluids, high GOR and significant sand production. Used on <1% of U.S. Lifted wells.

ARTIFICIAL LIFT SYSTEMS COMPARISON

Operating Condition	**Type Lift System**				
	Rod Pump	**Electric Submersible**	**Gas Lift**	**Hydraulic**	
Sand	Fair	Poor	Good	Fair	Good
Paraffin	Poor	Good	Fair	Good	Good
High GOR	Fair	Fair	Excellent	Fair	Good
Crooked Hole	Poor	Fair	Good	Good	Good
Corrosion	Good	Fair	Fair	Good	Good
High Volume	Poor	Excellent	Good	Good	Excellent
Depth	Fair	Fair	Fair	Excellent	Fair
Scale	Good	Poor	Fair	Fair	Good
Flexibility Volume	Fair	Poor	Fair	Excellent	Good

TYPICAL HYDRAULIC APPLICATIONS

- Directional Drilled Wells or Crooked/Deviated Holes
- Well Depth
- Net Fluid Volume
- Remote Locations
- Casing Size Restrictions
- Highly Corrosive Wells (Jet Pumps)
- Wells Just Coming Off Flowing Status
- High GOR Wells
- Low Profile Requirements
- “Town Site” Locations
- Remote Locations (Can be powered with Natural Gas Engines)
- Wells with Widely Variable Producing Rates
- Wells That Need Continuous Treatment for Corrosion or Paraffin Control
- Multiple Zone Completions
- Limited Space on Offshore Platforms

Installation and Service Manual for

Dual Vessel UNIDRAULIC System

Gravity Operated Liquid Level Control

Weatherford®
Artificial Lift Systems

INSIDE FRONT COVER

Weatherford®
Artificial Lift Systems

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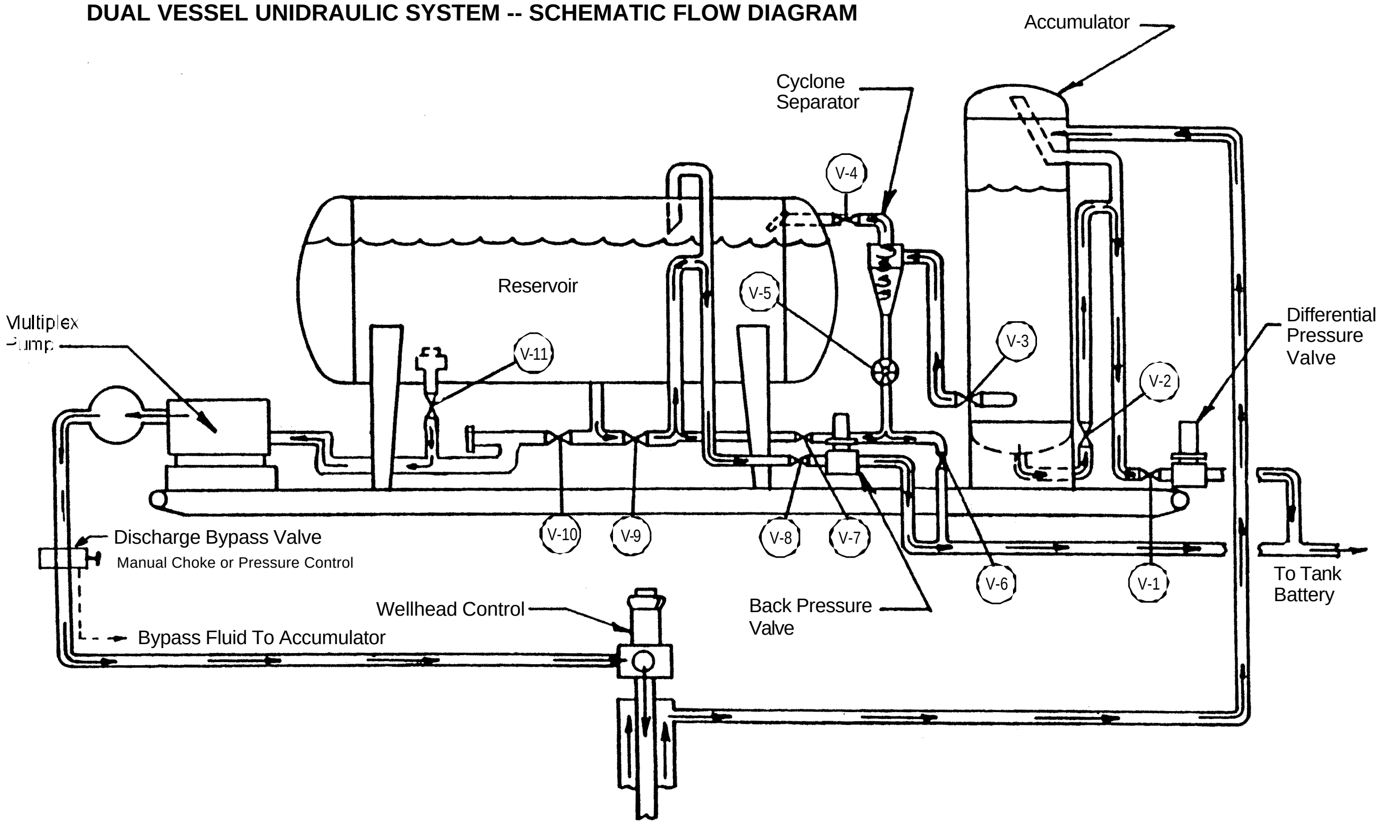
Unidraulic System
With Gravity Dump Liquid Level Control

The Unidraulic Power Fluid Conditioning Unit (PFCU) is a system for the cleaning of power fluid in a subsurface hydraulic pumping system. Fluid returning from the well (power fluid plus produced fluid) first enters the accumulator vessel which acts as a three phase separator. Gas and produced fluids are separated in this vessel before being discharged to the flow line. Power fluid is fed through the cyclone cleaner to remove solids. Overflow of clean fluid from the cyclone is then discharged into the reservoir vessel while the dirty fluid underflow is discharged into the flow line. The vessel serves as a reservoir for the clean power fluid and feeds the multiplex power pump.

Excess fluid from the accumulator vessel is discharged through a vented leg system which acts as a liquid level control while taking the excess liquid from either the bottom or top of the tank. The liquid is then discharged through a differential pressure valve to the flow line.

DUAL VESSEL UNIDRAULIC SYSTEM -- SCHEMATIC FLOW DIAGRAM



This differential pressure valve acts to maintain a constant pressure difference between the reservoir and accumulator vessels and thus, a constant flow through the cyclone.

Excess fluid from the reservoir vessel is also discharged through a vented leg level control which removes the fluid from either the bottom or top of the vessel. This fluid is discharged through a back pressure valve to the flow line. This back pressure valve is set to maintain a constant system pressure higher than flow line pressure.

Fluid which is to be used as power fluid is drawn from the reservoir vessel into the suction of the multiplex where it is elevated to operating pressure and circulated to the well.

INSTALLATION & OPERATION

The PFCU has been fabricated with the equipment necessary to provide sufficient power fluid to operate the subsurface jet pump or positive displacement pump based on the well information furnished prior to installation. In the event that well conditions change, it may be necessary to change some of the equipment for satisfactory performance such as multiplex pump plunger size or style and cyclone trim and feed nozzle size. After the unit is put into operation and the well stabilizes, adjustments or equipment changes may be made for optimum performance. A Weatherford Artificial Lift Systems service representative is available to assist in making necessary adjustments.

PFCU Location and Installation

Location of the PFCU at the well site is optional, consistent with good safety practice and convenience for locating well servicing equipment at the well. All field connections to the unit are made at the accumulator end of the skid. A convenient piping arrangement can be made by locating the unit between the well and the connection to the flow line to the tank battery. A piping guide for installation of the unit and wellhead hook-up is provided in this manual. See page 21.

The foundation for the PFCU must be level and adequate to rigidly support the operating unit with fluid loads. A concrete slab of suitable depth is most commonly used, however precast concrete beams or heavy timber beams may be suitable if securely anchored. Refer to the appropriate foundation plan for installation detail.

PFCU Start-Up Procedure

Before starting the Unidraulic System, read this section thoroughly to understand the procedure.

All surface connections on the unit and at the wellhead should be completed and the standing valve installed in the well before start-up.

Refer to the Check List section of this manual and check all items listed before start-up.

System Circulation

The first phase of the start-up procedure is intended to circulate the complete system in stages to flush out any debris that would create problems during operation. A supply of clean fluid, oil or water, is required for this purpose. (Note: Oil must be used if the multiplex pump is equipped with Fluid Seal Plungers). The volume required varies with well depth, flow line length and general condition of the system. However, seventy-five (75) barrels of clean fluid should be considered a minimum. The supply source may be from a suitable lease supply of from a truck mounted tank with adequate pumping pressure to charge the multiplex pump (5 psi minimum). A 2” threaded connection is provided on the multiplex pump suction piping from the reservoir vessel on the unit for the supply connection.

The first phase of circulation will be limited to the surface lines only. Ideally, bypass piping should be installed at the accumulator inlet connection from the well to bypass return directly into the flow line, downstream of the unit connection. If this is not possible, valves on the accumulator should be set to direct fluid through the accumulator and directly to the flow line. Valves V-1 and V-2 should be OPEN and valve V-3 CLOSED. On the suction piping under the reservoir vessel, valves V-10 and V-11 should be CLOSED.

At the wellhead, set the lever operated Wellhead Control Valve in the SHUT-OFF position (lever horizontal) and OPEN the bypass valve directly under the lever on the wellhead control. Inlet and outlet valves on the wellhead control should be OPEN. These valve settings will establish circulation through the surface lines only.

If the available fluid supply pressure is not sufficient to circulate the system, the multiplex pump may be used for this purpose. Being certain that the valve from the fluid supply source is OPEN, start the multiplex and establish circulation.

Circulation through this route should be continued until the flow line and all equipment upstream of the stock tank is filled. This will be accomplished when circulated fluid is being discharged into the stock tank. If available fluid supply limits this volume of circulation, the minimum circulation should be sufficient to displace the surface lines through the flow line check valve downstream of the unit flow line connection.

After minimum circulation of the surface lines has been completed, the wellhead control should be set to establish circulation through the well tubulars. The most desirable circulating course will direct fluid down the production return string (casing annulus or parallel tubing) and up the power fluid tubing. This minimizes the possibility of depositing solids on top of the retrievable standing valve.

To establish this course, shift the wellhead control lever to the PUMP OUT position (lever upward), then slowly CLOSE the wellhead control bypass valve. No changes in valve settings on the unit are required. Circulation in this mode should be continued to fill, then completely displace the volume of well tubulars (power fluid tubing AND casing annulus or parallel tubing).

If available fluid supply limits this volume of circulation in a casing free installation, and tubulars are known to be relatively clean, it may be satisfactory to follow an alternate tubular circulation procedure. For this alternate course, shift the wellhead control lever to the PUMP-IN position (lever downward) before closing the wellhead control bypass. This setting circulates fluid down the power fluid tubing and up the casing annulus. In this mode, minimum circulation should completely displace the volume of the power fluid tubing to flush solids out of the tubing and into the casing annulus.

After circulating well tubulars, the vessels on the unit may be filled. If the accumulator has been bypassed during circulation, return fluid may now be directed into this vessel. To accomplish this, set accumulator valves V-1 and V-2 OPEN and valve V-3 CLOSED, then reset the valves on the piping which has bypassed the accumulator. When the accumulator is filled, fluid will be discharged through the back pressure valve into the flow line.

Next, the reservoir vessel may be filled. OPEN reservoir valves V-8, V-9, V-4, V-5 and V-7. When the fluid level in the reservoir reaches and remains at the height of the vented leg, the system is filled with fluid.

While filling the vessels, if the wellhead control has been set in the PUMP-OUT position during tubular circulation, it should now be shifted to the PUMP-IN position as described for the alternate tubular circulating mode.

Pressure Control Valve Settings

As soon as adequate pressure is available in the vessels, pressure controls on the PFCU can be set for initial operation. The back pressure valve on the reservoir vessel outlet should be adjusted to open at 10 psi over the highest anticipated operating flow line pressure, or a minimum of 60 psi. This setting should not be higher than 125 psi on a standard unit to hold vessel operating pressure safely below the 175 psi setting of the reservoir relief valve. Next, set the differential pressure valve on the accumulator outlet at 40 psi over the setting of the back pressure valve. Maximum setting should be 175 psi to remain under the 225 psi accumulator relief valve setting.

STOP CIRCULATION – CHECK VALVE POSITION

Stop Circulation

The multiplex pump can now be shut down, if operated during the circulation procedure. Disconnect the fluid supply from the unit and replace the cap on the multiplex pump suction piping on the unit. OPEN reservoir valve V-11 to direct fluid from the reservoir to multiplex pump suction.

Check PFCU Valve Position

All valving on the PFCU should now be rechecked for correct operation of the system. The following steps will identify the correct position.

Selection of Power Fluid

The PFCU is designed so that either produced oil or water may be used as power fluid. This selection is achieved by the point at which excess fluid from each vessel is discharged into the flow line.

<u>Power Oil:</u> When oil is selected as the desired power fluid, the underflow valves on each vessel, V-2 and V-9, are set in the OPEN position. In this mode, excess fluid discharged from the vessels is drawn from the bottom of the vessel, thus water is discharged preferentially and oil is retained in the vessel.

<u>Power Water:</u> When water is selected as the desired power fluid, the underflow valves on each vessel, V-2 and V-9, are set in the CLOSED position. This forces excess fluid to be discharged through the gas vent line, thus oil is discharged preferentially from the top of the vessel and water is retained in the vessel.

Cyclone Underflow

Two alternate paths for cyclone underflow are possible. One which retains all available power fluid within the system to maintain the reservoir supply during periods of variable or limited supply of power fluid from the well returns, and the second for systems having an abundant and continuous supply of selected power fluid in the well returns.

The route of the first alternate combines the underflow with the reservoir discharge upstream of the level control leg. This is accomplished by setting valve V-6 CLOSED and V-7 OPEN. This valve setting stops the flow of any fluid which is passed through the cyclone from being discharged into the flow line during periods when the reservoir is not full. When this underflow path is chosen, it may be necessary to slightly close valve V-4 on the cyclone overflow to help establish an adequate underflow rate. It is also good practice to periodically check the reservoir underflow to be sure that normal flow is out of the vessel and not into it. This can be confirmed by closing valve V-9 and observing the fluid level in the reservoir vessel. If the level falls with valve V-9 closed, the fluid is incorrectly entering the vessel through this valve. This situation should be corrected by adjusting the differential pressure valve to increase differential between the two vessels, increasing the cyclone feed rate until the fluid level in the reservoir rises slowly. (See cyclone operation, Page 13, for additional information).

The second alternate path routes cyclone underflow directly into the flow line. For this route, OPEN valve V-6 and CLOSE valve V-7. When this path is chosen, the cyclone overflow valve V-4 should be fully OPEN with underflow valve V-5 adjusted to control the underflow rate. In this mode, reservoir vessel pressure must always be maintained at a higher level than flow line pressure by proper adjustment of the back pressure valve.

To summarize the proper valve settings on the unit, valves should be set as tabulated below for operation on power oil or power water.

VALVE POSITION GUIDE (Refer to Schematic Illustration ON Page 5)			
Valve No.	Valve Setting		
	Either Power Fluid	Power Oil	Power Water
V-1	Open	---	---
V-2	---	Open	Closed
V-3	Open	---	---
V-4	Open	---	---
V-5	Open	---	---
V-6*	Closed	---	---
V-7*	Open	---	---
V-8	Open		
V-9	---	Open	Closed
V-10**	Closed	---	---
V-11	Open	---	---

*Setting is optional, but never open V-6 and V-7 at the same time.

** This is the emergency low level suction valve and should always be closed during normal operation.

CYCLONE OPERATION

Correct sizing and adjustment of the cyclone operation is the most important element in assuring optimum performance of the PFCU system. For this reason, this procedure should be reviewed before putting the Unidraulic System in operation to gain understanding of the adjustments to be made.

Proper adjustment of the flow rate and differential pressure across the cyclone establishes the cleaning efficiency of the cyclone, assures proper balance of fluid discharge from both vessels and, in turn, affects the fluid level in each vessel. This fluid flow is optimized when the differential pressure is between 30 and 50 psi and the flow rate into the cyclone is a minimum of 15% greater than required by the multiplex pump suction. This provides adequate underflow from the cyclone for efficient cleaning action and also delivers excess fluid into the reservoir to maintain proper fluid level in the vessel.

Flow Control

Flow rate into the cyclone is established by the feed nozzle size and the differential pressure across the cyclone inlet and overflow discharge. This differential pressure is the difference between accumulator vessel pressure and reservoir vessel pressure.

Several cyclone feed nozzle sizes are available to select the range of flow rate required. Adjustment of the differential pressure between 30 and 50 psi permits finer tuning for an additional plus or minus 10% flow rate variation. Note that the cyclone may be damaged if pressure differential exceeds 50 psi, and cleaning efficiency is impaired at less than 30 psi differential.

Cyclone feed nozzle sizing charts on Pages 15, 16 and 17 tabulate approximate flow rates through the available feed nozzle sizes at differential pressures ranging from 30 to 50 psi. Flow rates are listed for three fluids having different specific gravities. Actual flow rates may be estimated by using figures listed for the fluid having the closest specific gravity to that of the power fluid being used. Final adjustment of the cyclone feed rate is made by adjusting the differential pressure to maintain discharge of excess fluid from the reservoir vessel into the flow line.

Efficient separation of solids in the cyclone requires the correct pressure differential (30 psi to 50 psi) AND continuous underflow out of the bottom connection of the cyclone. The alternate flow courses for cyclone underflow and control of the underflow rate are described on Page 10. Cyclone underflow must be checked routinely during operation of the unit to be certain proper underflow rate is maintained. Generally, a maximum underflow rate of 100 barrels per day should be maintained, provided the cyclone overflow rate is sufficient to sustain underflow from the reservoir vessel.

LIQUID LEVEL SIGHT GLASSES

The liquid level gauge valves furnished with the sight glasses on each vessel provide automatic shut-off in case of glass breakage. It is important in using these valves that their operation is understood to assume meaningful readings and proper settings.

When checking liquid level, it is good practice to purge the glass by closing the valves and opening the drain cock. This will vent out the contents of the glass. After venting, the valves should then be reopened just enough to allow filling of the glass and then opened fully when all flow into the glass ceases. This will permit the check valve to close automatically in case of gauge failure, but not before the glass is filled.

3" CYCLONE SIZING CHART FOR UNIDRAULICS
.75" I.D. SPIRAL VORTEX

Feed Nozzle Size	DIFFERENTIAL PRESSURE - PSI				
	30	35	40	45	50
B/D Across Cyclone Using Power Fluid I					
.500	748	832	898	939	972
.542	990	1089	1166	1221	1256
.600	1122	1221	1309	1375	1421
B/D Across Cyclone Using Power Fluid II					
.500	630	756	816	854	884
.542	900	990	1060	1110	1142
.600	1020	1110	1190	1250	1292
B/D Across Cyclone Using Power Fluid III					
.500	648	720	777	814	842
.542	858	943	1010	1058	1088
.600	972	1058	1134	1191	1231

Feed Nozzle Part Numbers

Nozzle Size	Part Numbers
.500	180-894
.542	180-935
.600	180-895

Power Fluid

I	40 Gravity Oil – Specific Gravity .825
II	Fresh Water – Specific Gravity 1.00
III	Brine Water – Specific Gravity 1.10

4" CYCLONE SIZING CHART FOR UNIDRAULICS
1.50" I.D. SPIRAL VORTEX

Feed Nozzle Size	DIFFERENTIAL PRESSURE – PSI				
	30	35	40	45	50
B/D Across Cyclone Using Power Fluid I					
.500	1357	14534	528	1590	1635
.542	1563	1663	1740	1811	1862
.600	1769	1874	1954	2032	2090
.700	1961	2081	2172	2259	2324
.800	2001	2137	2243	2333	2400
B/D Across Cyclone Using Power Fluid II					
.500	1234	1321	1389	1445	1486
.542	1421	1512	1582	1646	1693
.600	1608	1704	1776	1847	1900
.700	1783	1892	1975	2054	2113
.800	1819	1943	2039	2121	2182
B/D Across Cyclone Using Power Fluid III					
.500	1176	1259	1324	1377	1416
.542	1354	1441	1508	1567	1613
.600	1532	1624	1693	1760	1811
.700	1699	1803	1882	1657	2014
.800	1734	1852	1944	2021	2079

Feed Nozzle Part Numbers

Nozzle Size	Part Number
.500	180-894
.542	180-935
.600	180-895
.700	180-896
.800	None Needed

Power Fluid

I	40 Gravity Oil – Specific Gravity .825
II	Fresh Water – Specific Gravity 1.00
III	Brine Water – Specific Gravity 1.10

4” CYCLONE SIZING CHART FOR UNIDRAULICS
1.50“ & !.75” I.D. SPIRAL VORTEX
HV

Feed Nozzle Size	DIFFERENTIAL PRESSURE – PSI				
	30	35	40	45	50
B/D Across Cyclone Using Power Fluid I					
.500	1357	1453	1528	1590	1635
.542	1563	1663	1740	1811	1862
.600	1769	1874	1954	2032	2090
.700	1961	2081	2172	2259	2324
.800	2001	2137	2243	2333	2400
.850HV	2510	2735	2803	2926	3036
B/D Across Cyclone Using Power Fluid II					
.500	1234	1321	1389	1445	1486
.542	1421	1512	1582	1646	1693
.600	1608	1704	1776	1847	1900
.700	1783	1892	1975	2054	2113
.800	1819	1943	2039	2121	2182
.850HV	2281	2436	2554	2658	2738
B/D Across Cyclone Using Power Fluid III					
.500	1176	1259	1324	1377	1416
.542	1354	1441	1508	1567	1613
.600	1532	1624	1693	1760	1811
.700	1699	1803	1882	1957	2014
.800	1734	1852	1944	2021	2079
.850HV	2173	2324	2439	2533	2612

Feed Nozzle Part Numbers

Nozzle Size	Part Number
.500	189-472
.542	189-466
.600	189-467
.700	189-468
.800	189-469
.850HV	189-470

Power Fluid

I	40 Gravity Oil – Specific Gravity .825
II	Fresh Water – Specific Gravity 1.00
III	Brine Water – Specific Gravity 1.10

INSTALLATION OF DOWNHOLE PUMP AND SYSTEM START-UP

When all of the preceding start-up procedures have been accomplished, the system will be ready for installation and starting of the downhole pump.

Install Downhole Pump

Remove the catcher assembly from the wellhead control and attach to the fishing neck of the swab nose assembly on the top of the pump. Be certain the catcher slip release nut is screwed down tightly to securely latch the pump into the catcher slips. Lower the pump into the wellhead control and make up the catcher union nut tightly to secure the catcher to the wellhead control. With the pump still hanging in the catcher, prepare to restart the multiplex pump.

Set the lever operator on the wellhead control in the PUMP-IN position (lever downward), OPEN the wellhead control bypass, and check inlet and outlet valves to be certain they are OPEN.

Restart PFCU Multiplex Pump

It the PFCU is equipped with a manual operated discharge bypass choke valve on the multiplex discharge – normally used with a downhole positive displacement pump – adjust this bypass valve to a HALF OPEN position before starting the multiplex.

If the unit is equipped with a pressure operated discharge bypass pressure control – normally used with a downhole jet pump – adjust this valve or a reduced pressure setting by loosening the lock nut and backing out the spring adjusting screw two turns before starting the multiplex. Recheck the valve position guide on Page 12 to be certain all valves are properly set.

The multiplex may now be restarted to establish circulation from the unit to the well. CLOSE the wellhead bypass valve and circulate fluid into the well for about ten minutes before releasing the unit. Do this by backing off (counter-clockwise) the slip releasing nut on the wellhead catcher assembly. Continue circulating fluid into the well to circulate the pump to bottom.

It is good practice to reduce the circulation rate into the well as the pump nears bottom by opening the wellhead bypass. This will slow the travel speed of the pump as it enters the bottom hole cavity. When the pump is seated in the cavity, operating pressure will increase and the wellhead bypass can be CLOSED.

Set the operating speed of the downhole positive displacement pump at the desired rate by adjusting the discharge bypass choke valve.

Set the operating pressure of the downhole jet pump by adjusting the discharge bypass pressure control to the desired pressure.

After the system reaches a stabilized pumping condition, recheck the vessel fluid levels and pressures and make necessary adjustments for optimum performance.

Recheck the settings on the suction and discharge hi-low safety switches in the shut-down panel and adjust to following settings:

Suction Shut-Down Switch

High	30 psi over reservoir vessel back pressure Valve setting
Low	60 psi under high shut-down setting

Discharge Shut-Down Switch

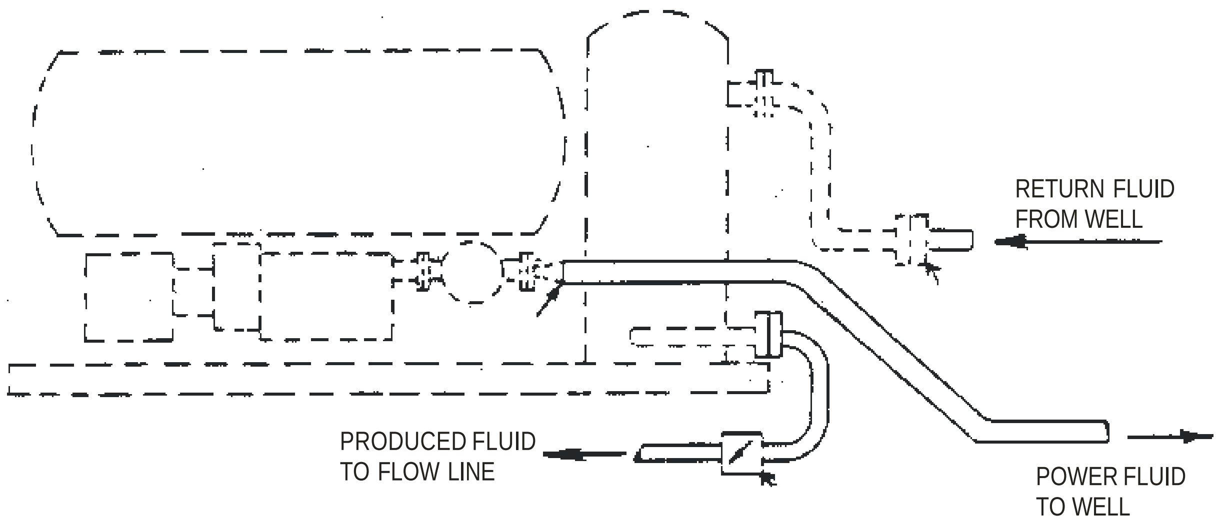
High	200 psi over operating pressure maximum setting at pressure rating of plunger size In multiplex pump
Low	500 psi under high shut-down setting

Recheck multiplex relief valve and set opening pressure as the final safety relief in the discharge system. Adjust the opening pressure by loosening the jam nut and turning the adjusting screw clockwise to increase pressure or counter-clockwise to reduce pressure. The relief valve should be set to open at 300 psi over the setting of the high pressure shut-down on the discharge shut-down switch. Maximum opening pressure should not exceed 3500 psi on the MCA medium pressure fluid end or 4500 psi on the HCA high pressure fluid end.

After Storage Start-Up

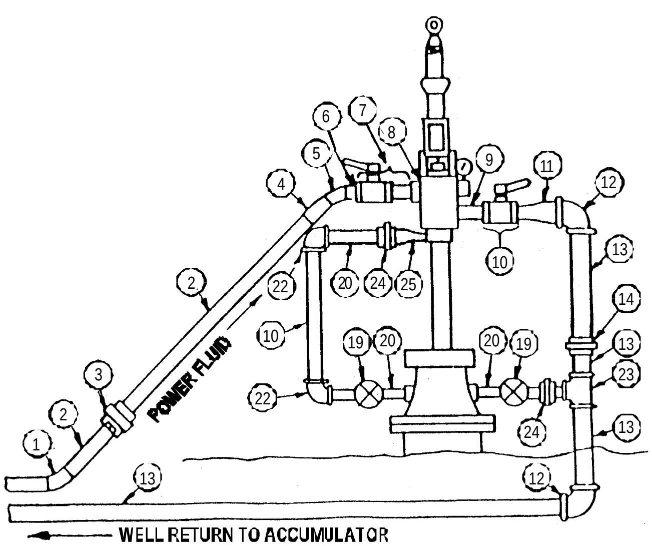
For start-up procedure after periods of storage of the PFCU, see the Preventative Maintenance Section of this manual.

PLUMBING GUIDE -- PFCU

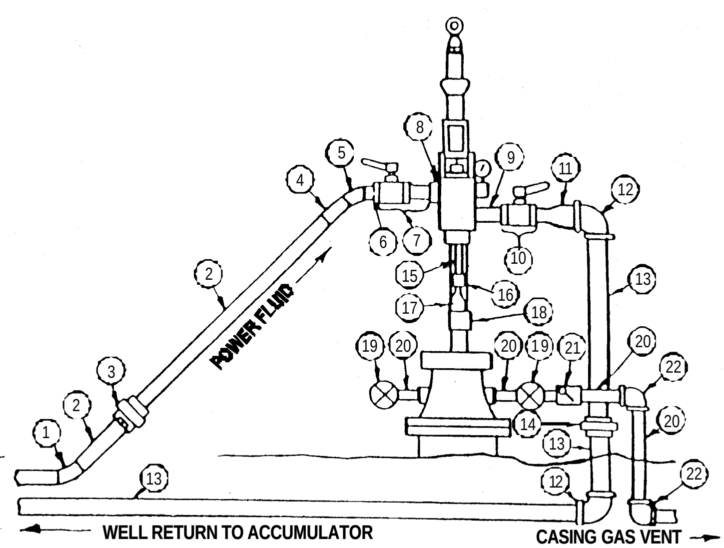


1 **2” Sch. 160 BFW** 2 **3” 150# R.F. Flange** 3 **3” Check Valve**

Item No.	Description	No. Req'd. (PF)	No. Req'd. (CF)		Item No.	Description	No. Req'd. (PF)	No. Req'd. (CF)
1	2" or 2-1/2" 45° Weld Ell	1	1		14	3" Hammer Union	1	1
2	2-3/8" or 2-7/8" Tubing	2	2		15	1-1/4" Nipple	1	0
3	2" or 2-1/2" Unibolt Coupling	1	1		16	1-1/4" Coupling	1	0
4	2" x 2-1/2" Weld Reducer	(1 Optional)			17	2-3/8" x 1-1/4" Swage	1	0
5	2" 45° Weld Ell	1	1		18	2-3/8" Coupling	1	0
6	Flange Assembly (510-023)	1	1		19	2" Gate Valve	2	2
7	1-1/2" Ball Valve	1	1		20	2" Nipple	5	7
	Consisting of:				21	2" Check Valve	1	0
	1 510-018 Body Group				22	2" Ell	2	2
	1 180-440 Flange				23	3" x 3" Tee	0	1
	1 180-480 Ring				24	2" Hammer Union	0	2
	4 180-054 Screw				25	2" x 1" Swage	0	1
	1 502-134 Tube							
8	Wellhead Control Assembly (280-374)	1	1					
9	2" x 6" XXH Nipple	1	1					
10	2" Ball Valve (500-016)	1	1					
11	2" x 3" Swage Nipple	1	1					
12	3" Ell	2	2					
13	3" Line Pipe	3	3					



CASING FREE



PARALLEL FREE

Before Start-Up Check List

1. VESSEL

______ A. Check base bolts for tightness on both tanks
______ B. Check all flange bolts
______ C. Check sight glass seals for tightness
______ D. Check cyclone connection and manway bolts
______ E. Check all brace “V” bolts to assure tightness
______ F. Check all valves for proper setting.
See start-up instructions

2. TRIPLEX

______ A. Check base bolts for tightness
______ B. Check valve caps for tightness
______ C. Check flange bolts for tightness
______ D. Check oil level in Triplex power end
______ E. Check oil level in gear reducer and transmission
______ F. Check oil level in lubricator
______ G. Check oil level in chemical pump
______ H. Check operation of oil level switches on high and low settings and tattletales. Set oil level switch settings.
______ I. Pump up lubricator lines for lubrication
______ J. Check hose connections to Shut-Down panel for tight connections. Hoses must not contact sharp edges.
______ K. Check operation of Suction and Discharge Hi-Low Safety Switches in Shut-Down panel. Set shut-down contacts for start-up protection as follows on the next page.

Suction Shut-Down Switch

______ High 30 psi higher than anticipated flow line pressure, 125 psi maximum

______ Low 30 psi lower than anticipated flow line pressure

Discharge Pressure Shut-Down Switch

______ High 200 psi higher than anticipated operating pressure. Maximum at pressure rating of plunger size in multiplex pump

______ Low 300 psi lower than anticipated flow line pressure

______ L. Spray all kill switch electrical connections with liquid weather proofing

______ M. If electric, start chemical pump and pump into triplex suction before start-up. Check rotation for proper direction

______ N. Check flexible coupling alignment and couple. Or belt drive alignment and belt tension

PRIME MOVER

ELECTRIC MOTOR

______ A. Check base bolts for tightness
______ B. Check rotation for proper direction

MULTI-CYLINDER ENGINE

______ A. Check fluid levels in radiator and crankcase
______ B. Check fuel supply and set regulator
______ C. Check base bolts for tightness
______ D. Check alignment of coupling
______ E. Check kill switch “hook-up” to magneto

Trouble-Shooting Procedure

To minimize maintenance costs on surface and subsurface equipment, it is important that the operation of the power fluid conditioning unit be checked at regular intervals and corrective action taken when improper operation is detected.

Following is a check list of four maintenance items which should be regularly monitored. In addition is a list of five possible problems which may be encountered with probable cause and solution as a trouble-shooting guide. In each of these lists, page references are noted where applicable, referring to the INSTALLATION and START-UP INFORMATION section of this manual which contains additional related information.

Check for Proper Operation – To determine if the PFCU is operating properly, the following items should be regularly monitored:

1. **Fluid Level in Vessels** – Both accumulator and reservoir vessels should be checked for proper fluid level.
   Reference: Page 10.

2. **Cyclone Underflow** – It is essential that the cyclone underflow be operating continuously. The flow indicator or sight glass should be checked to determine this.
   Reference: Pages 7, 8 and 9.

3. **Vessel Pressures** – The pressure levels should be checked to determine that they are within prescribed limits. (Normally, the reservoir vessel should be approximately 10 psi above flow line pressure, and the accumulator should be 30 to 50 psi above the reservoir pressure).
   Reference: Pages 7 and 8, 11 and 12.

Note: Accurate and reliable pressure gauges are needed for these checks

4. **Level of Oil** – Water Interface in Reservoir – The level of oil-water interface in the reservoir vessel should be kept as far from the power fluid discharge level as practical. When making this check it is good practice to vent the sight glass through the valve provided.
   Reference: Page 12.

If the system is not operating properly, corrective action should be undertaken as indicated in the Trouble-Shooting Guide.

TROUBLE-SHOOTING GUIDE

Problem	Solution
1. Insufficient fluid in accumulator	Too much fluid may be discharging through the cyclone. Reduce differential pressure between vessels by backing out adjustment on Accumulator Differential Pressure valve (do not adjust lower than 30 psi differential) or re-size cyclone feed nozzle to reduce feed rate. See Problem 4. Reference: Pages 11, 12 & 13.
2. Insufficient fluid reservoir vessel	Too little fluid may be entering from the cyclone. Increase differential pressure between vessels by turning in adjustment on Accumulator Differential Pressure valve (do not adjust higher than 50 psi difference) or re-size cyclone trim to increase feed rate. See Problem 4. Reference: Pages 11, 12 & 13. Check cyclone underflow for excess flow. Reference: Page 9. Be certain that valves V-6 and V-7 are not both open at the same time. Reference: Page 10.
3. Water building in reservoir vessel when attempting to operate with power oil	This indicates too much oil is being lost from the cyclone underflow or that the vessel underflow valves are not properly set. Reduce cyclone underflow rate and check that valves V-2 and V-9 are open. Reference: Pages 9 & 10.
4. Loss of fluid in system	4a. This can be caused when the system is shut down and valves V-6 and V-7 are both open. Always make certain one of these valves is closed. Reference: Pages 9 & 10.

TROUBLE-SHOOTING GUIDE (Cont'd.)

Problem	Solution
4. Loss of fluid in system (cont'd.)	4b. During shut-down, the Accumulator Vessel will drain to the flow line if valve V-6 is OPEN. If operating with V-6 OPEN and V-7 CLOSED, during any planned shut-down, valve V-6 should be closed for the duration of shut-down. Be sure to re-open when Unit is re-started.
	4c. Some wells have a tendency to head off with slugs of gas and fluid. When this occurs with a casing return system, there may not be sufficient fluid in the PFCU to refill the casing and the system will shut down due to low discharge pressure (loss of fluid). This can frequently be overcome by restricting return flow from the well with an adjustable choke at the wellhead. If this is not successful, more reservoir capacity is needed
5. Unit shut-down by Shut-down controls due to:	
a. High discharge pressure	5.a Possibly caused by:
	5a. 1. Shut-down safety switch high pressure contact set too close to normal pressure. Check setting. Reference: Page
	5a. 2. Any blockage in the well, Unit or flow line system. Recheck all valve settings.
	5a. 3. Malfunction of Discharge Bypass Choke Valve or Pressure Controller. Adjust bypass or inspect and repair if necessary.
	5a. 4. Downwell positive displacement pump may have stopped stroking due to sticking. If unable to restart downhole pump, circulate to surface for inspection.
	5b. 2. Loss of fluid in Reservoir Vessel resulting in fluid starved suction to Multiplex Pump and reduced discharge pressure. See Items 2 and 4 of Trouble-Shooting Guide.

TROUBLE-SHOOTING GUIDE (Cont'd.)

Problem	Solution		
b. Low Discharge Pressure	5b.	1.	Shut down safety switch low pressure contact set too close to normal operating pressure. Check setting.
	5b.	2.	Loss of fluid in Reservoir vessel resulting in fluid starved suction to multiplex pump and reduced discharge pressure. See Items 2 and 4 of Trouble Shooting Guide.
	5b.	3.	Failure of high pressure safety switch to shut down unit. Multiplex Relief Valve would open at pre-set high pressure, then bleed off to minimum pressure which should be lower than setting of low pressure shut-down contact. Relief valve closes when pump shuts down. Recheck safety switch.
	5b.	4.	Any cause of loss of pressure in surface discharge lines or in subsurface circuit. Restart Unit and check discharge pressure build-up.
5.c High suction pressure	5c.	1.	Shut-down safety switch high pressure contact set too close to Reservoir Back Pressure valve setting. Recheck settings. Reference: Page 14.
	5c.	2.	Any cause of high Reservoir pressure. If Back Pressure valve is operating properly, check for any restriction in flow line down stream of Unit.
5d. Low suction pressure	5d.	1.	Shut-down safety switch set too close to normal Reservoir pressure. Recheck setting. Reference: Page 14.
	5d.	2.	Any cause of loss of pressure in Reservoir below proper setting of low pressure shut-down. Restart system and check Reservoir pressure.

UNIDRAULIC PREVENTATIVE MAINTENANCE SCHEDLE

A. Daily Maintenance

1. Check lube oil levels in both Triplex and Gear Reducer. (This can be done by checking level in safety switch gauges).
2. Check lubricator for proper level and operation.
3. Check plungers for excessive leakage.
4. Check stuffing box nut for tightness.
5. Check plunger chamber drain line, making sure it is clear of obstructions.
6. Drain plunger leakage sump tank is required.
7. Check underflow on bottom of cyclone.
8. Check pump for any abnormal vibration or noise. (See items 3 and 4 under Weekly Maintenance).
9. Check fluid in vessel for proper level.

B. Weekly Maintenance

1. Check lube oil levels by shutting unit down and checking with dip stick at back of pump, and check plug on side of gear reducer case. Inspect oil for contamination and change if necessary.
2. Check and test High-Low oil level safety switches for proper operation.
3. If Multiplex pump is equipped with Fluid Seal Plungers, remove plunger clamps and check plunger mandrel for looseness. If loose, remove plunger and tighten or replace mandrel cap screw.
4. Check pump while running for any abnormal noise or vibration in fluid cylinder. (if any, recheck item 3 or pull and check valves for washed seals or bad valves).
5. Check for leaks between fluid cylinder and frame or stuffing box and frame (if found, replace stuffing box seal).

UNIDRAULIC PREVENTATIVE MAINTENANCE SCHEDULE (Cont'd.)

C. Monthly Maintenance

1. Drain and refill crankcase on Triplex and gear reducer every six months, or as often as required to maintain a clean sludge free lube oil of the proper viscosity.

2. Clean crankcase air breather with non-explosive solvent.

3. Check all studs, nuts and capscrews for tightness.

4. Inspect Falk Coupling for proper lubrication. Add grease if necessary.

5. Check rotation of Triplex on start-up electric motor.

D. Storage

If the pump is to be idle for longer than one week, it should be prepared for storage as follows:

1. Drain and clean crankcase thoroughly. Leave drain open and install 90° elbow, pointing downward, to permit air circulation and prevent condensation build-up

2. Coat all bearings, finished surfaces, and entire inside surface of crankcase with a rust inhibiting oil.

3. Remove plungers and packing; clean and coat with rust inhibiting oil.

4. Remove fluid cylinder valves allowing cylinder to be thoroughly cleaned and drained.

5. Coat entire cylinder, valves and parts, with a rust inhibiting oil.

6. Thoroughly inspect pump and rotate crankshaft once a month. Recoat with rust inhibiting oil where necessary.

E. Start-Up After Storage

Any pump that has been in storage, either after field use or as shipped from the plant, will need a thorough inspection to make sure it has not been damaged in any way and that all parts are properly in place.

Failure to observe the following points can result in serious damage:

1. Remove all covers on both power end and fluid end; thoroughly clean and inspect all parts and finished surfaces.

2. Check all bearings to make sure they are clean and in good condition.

3. Make sure valves, plungers and packing are properly installed and in good condition.

4. Carefully tighten all bolts, nuts, studs and working connections.

5. Fill power end to the proper level with clean oil of the proper viscosity. Make sure oil is poured into the crosshead reservoir and is worked into all bearings.

6. Fill packing lubricator and pump lines. Check by breaking connection at stuffing box, working lubricator plunger until oil appears.

Installation

and

Service Manual

for

Single Vessel

UNIDRAULIC System

With Instructions For

Vessel Unit

And

Power Cleaning Unit

Weatherford®

Artificial Lift Systems

INSIDE FRONT COVER

Weatherford®
Artificial Lift Systems

Table of Contents

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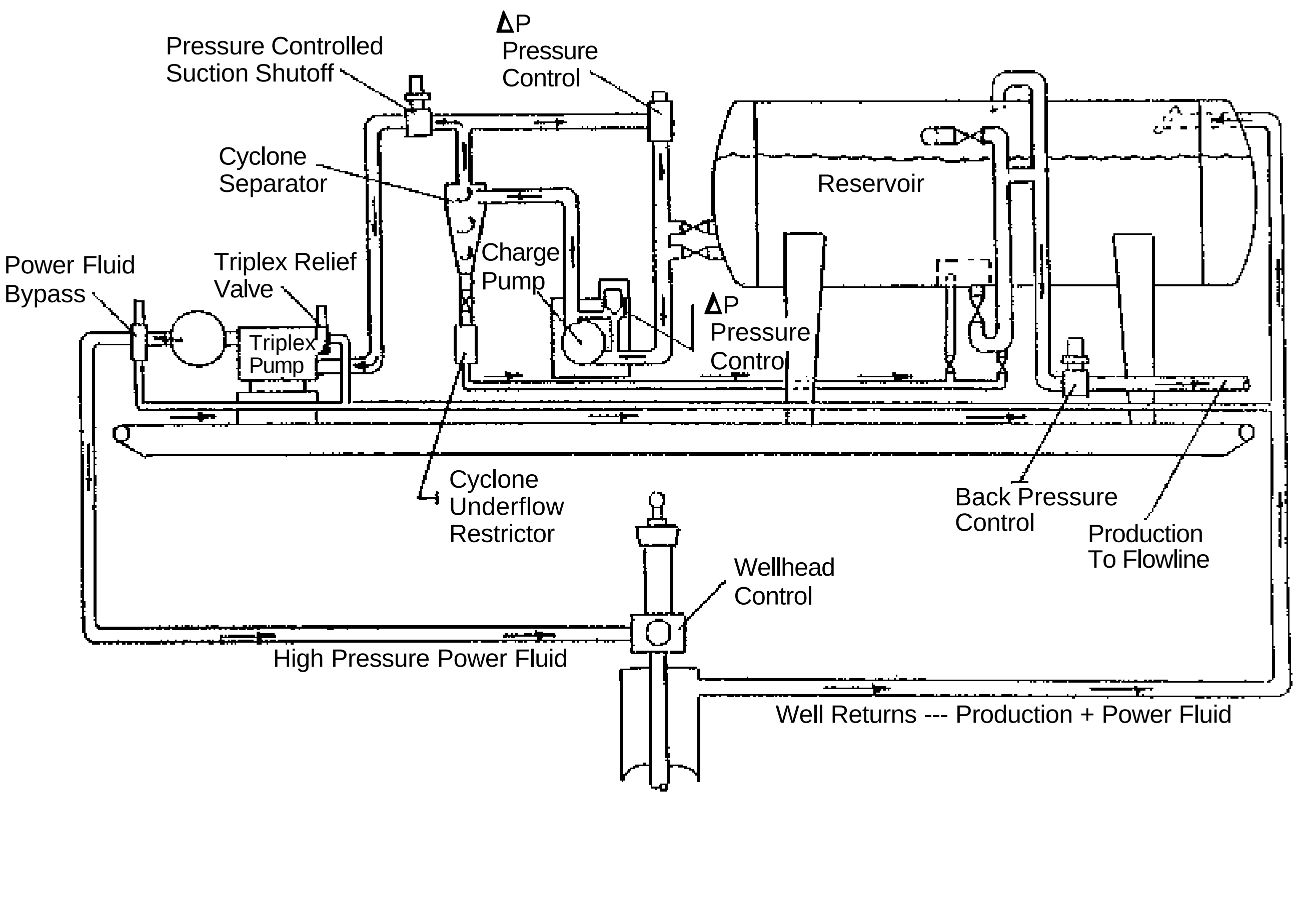
Principal of Operation and System Flow

The Single Vessel Unidraulic System provides a means for cleaning produced fluid to be used as power fluid and for circulating the power fluid at sufficient pressure to operate the subsurface hydraulic pump. The system can be operated to selectively reserve either produced oil or water for use as power fluid. When operated as a power oil system, produced water is preferentially discharged from the system, reserving all produced oil within the vessel until the power oil requirement is met. As a power water system, produced oil is preferentially discharged to establish a supply of power water.

Fluid returning from the well is a mixture of produced oil, water and gas, plus exhaust power fluid. It enters the vessel through an inlet diffuser. Four paths are available to discharge from the vessel: a gas outlet at the top, a fluid outlet near the top and a fluid outlet at the bottom of the vessel, all connected to the flow line through a back pressure valve; and the power fluid outlets on the side of the vessel which supply power fluid to the triplex pump.

SINGLE VESSEL UNIDRAULIC SYSTEM -- SCHEMATIC FLOW DIAGRAM



Power Oil System Flow

When set to operate as a power oil system, produced gas is discharged out the top vessel outlet; produced oil and water are discharged out the bottom vessel outlet. The back pressure valve is set to maintain a constant pressure on the vessel somewhat higher than maximum flow line pressure. The liquid level in the vessel is controlled by means of a gravity dump leg in the bottom outlet piping which permits flow from this outlet only when the liquid level is at the desired height in the vessel. Water settles to the lower portion of the vessel and is preferentially discharged to the flow line. Produced oil is discharged from this outlet only when the water level has been drawn down to the bottom of the vessel. In this way, a supply of oil is held in the vessel to supply power oil to the triplex pump.

Two power fluid outlets are provided to assure the greatest reserve volume of power oil on wells having either a high water-cut or high gas volume. For high water-cut wells, the upper outlet is used, permitting a larger volume of water accumulation in the vessel below this outlet before the storage of oil is depleted. In high gas volume wells, the lower outlet is used. This provides the greatest volume of power oil storage for operation during periods of several minutes when only gas and no fluid is being returned from the well.

Power Water System Flow

When set for power water operation, all gas is discharged to the flow line from the top vessel outlet. Produced oil and water are discharged from the side outlet near the top of the vessel. The back pressure valve on the discharge line maintains constant vessel pressure. The lower power fluid outlet is always used when operating on power water. This assures the greatest reserve volume of power water.

Power Fluid Cleaning

The power fluid cleaning system on the Single Vessel Unidraulic uses a charged hydrocyclone arrangement to remove solids from the power fluid. Fluid is supplied from the Vessel Unit to the suction of a rotary vane-type-charging pump where fluid pressure is increased to meet requirements of the cleaning system. Discharge from this pump is directed into the cyclone separator. Solids removed from the fluid are discharged out the bottom of the cyclone and returned to the vessel and ultimately to the flow line. The cleaned power fluid is discharged out the top of the cyclone and directed to the triplex suction. Pressure control valves in the system maintain the required differential pressures for optimum fluid cleaning efficiency and suitable suction pressure to the triplex.

High Pressure Power Fluid

The triplex pump transfers energy to the power fluid at sufficient pressure to operate the downhole hydraulic pump. A spherical discharge dampener reduces discharge pressure pulsations to an acceptable level. A discharge bypass valve controls the power fluid flow to the well by discharging excess volume back to the vessel. This may be either a manually adjusted choke bypass, used for wells equipped with a downhole reciprocating pump, or a pressure controlled bypass used with the downhole jet pump to control maximum operating pressure to the well.

Alternate Power Fluid Supply Storage

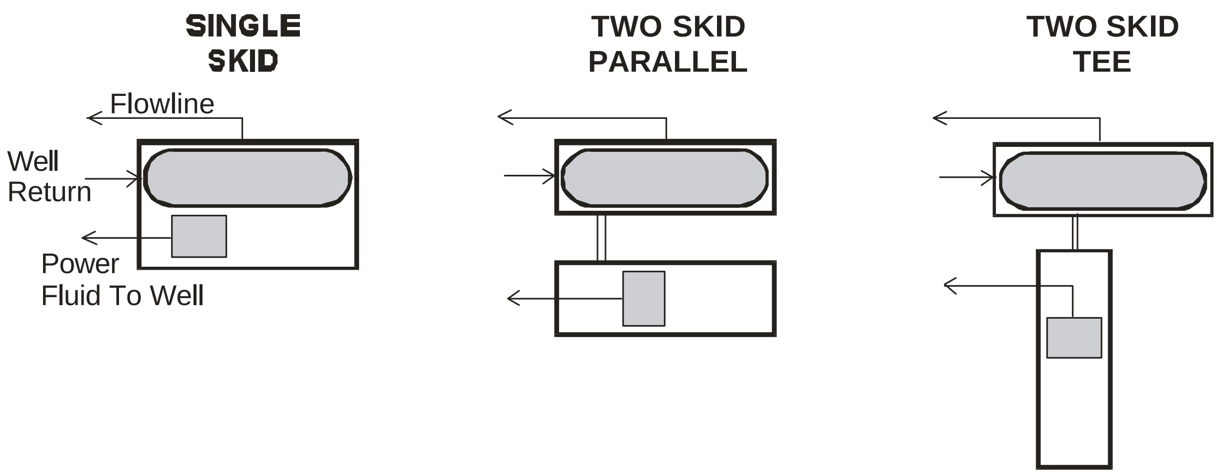
In an alternate system arrangement, an atmospheric power fluid tank may be used in place of the Vessel Unit to provide power fluid storage. The tank should be constructed to achieve gas separation at atmospheric pressure and sized to provide a reliable supply of the selected power fluid to the Power Cleaning Unit. While some gravity separation of solids from the power fluid will be achieved in this tank, final removal will be accomplished through the charged cyclone cleaning system in the Power Cleaning Unit.

INSTALLATION

Location and Hook-Up

Location of the Single Vessel Unidraulic at the well site is optional, consistent with good safety practice and convenience for moving well servicing equipment to the well. All field connections to the Unit are made from one end of the package. Plumbing guides identify these field connections and suggested hook-up arrangements for both the Unidraulic and Wellhead installations.

Lower horsepower units may be furnished as a single skid package. Larger units are on two skids, consisting of the Vessel Unit and the Power Cleaning Unit. Typical skid arrangements are illustrated below.



Foundation

The foundation of the Unidraulic package must be level and adequate to rigidly support the operating Unit with fluid loads. The foundation system used varies with soil conditions at the location and may be a concrete slab, cast concrete or wooden beams in gravel, or suitable raised pipe supports. The unit must be suitably anchored to prevent movement in operation. A foundation plan identifies location of skid beams and field connections.

START-UP PROCEDURE

BEFORE STARTING THE SINGLE VESSEL UNIDRAULIC SYSTEM, READ THIS SECTION THOROUGHLY TO UNDERSTAND THE ENTIRE PROCEDURE.

All surface connections to the Unit and at the Wellhead should be completed before start-up. Refer to Valve Reference illustrations for Vessel Unit, Power Cleaning Unit and Wellhead connections. The vessel bypass plumbing is to be installed as shown on the Vessel Unit field hook-up schematic.

Start-Up Check List

Refer to the Before Start-Up Check List section of this manual and be certain to check off all items listed before start-up.

System Circulation

The first phase of the start-up procedure is intended to circulate the complete system in stages to flush out any debris that would create problems during operation. The first stage limits circulation to the surface lines only; the second stage circulates the well system. During these two stages, returns are to bypass the Vessel Unit to avoid accumulation of debris in the vessel or cleaning system. The final stage will circulate the entire system before running the downhole pump into the well.

A supply of clean fluid, oil or water, is required for this circulation procedure and fill-up of the system. If Fluid Seal Plungers are installed in the triplex, oil must be used. The volume required varies with well depth, flow line length and general condition of the system. However, seventy-five (75) barrels of clean fluid should be considered the minimum. The supply source may be from a suitable lease supply or from a truck mounted tank. A 2” threaded connection is provided on the Vessel Unit piping for this start-up supply connection. Refer to Valve Reference illustrations for valve identification.

Vessel Fill-Up

Before filling Vessel Unit, place all valves in the CLOSED position, then: OPEN Valves V-1 and V-11. Connect fluid supply and fill vessel to capacity.

Surface Lines Circulation

To set up the system for this circulating stage, adjust system valves as follows:

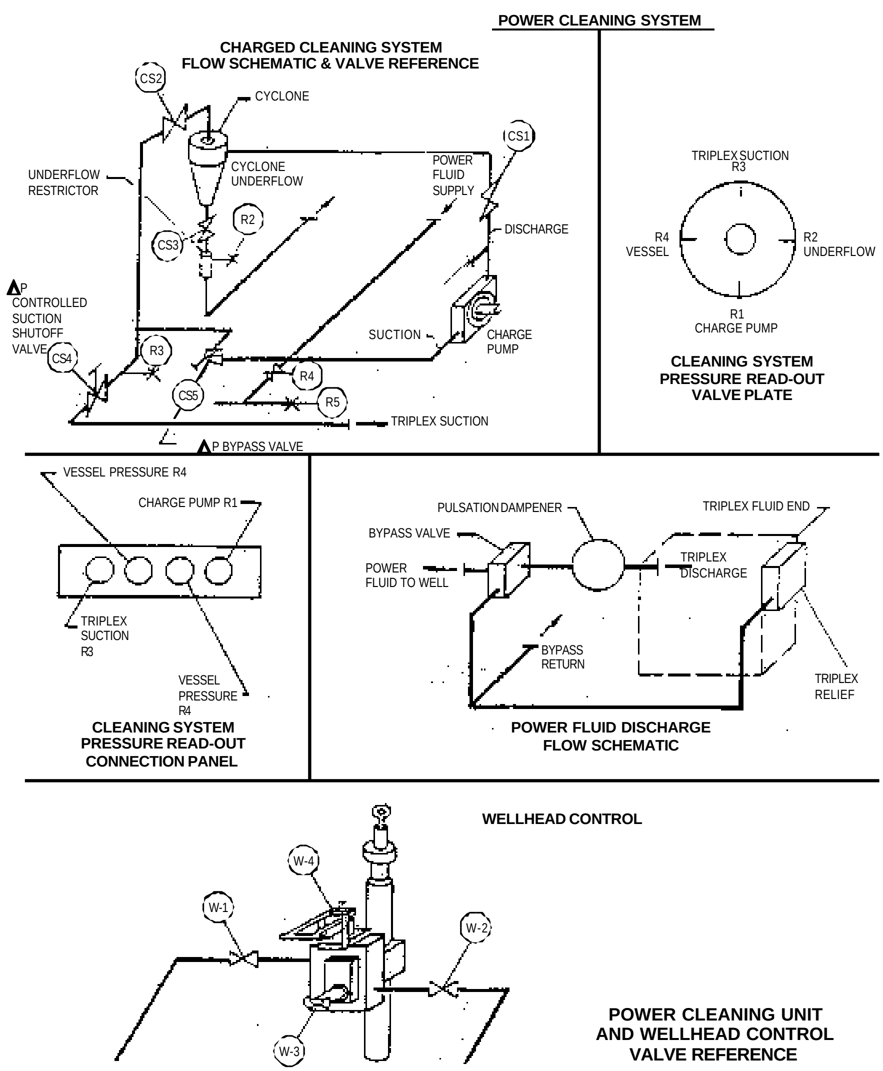
1. Vessel Unit – OPEN Valves V-5 and V-10. Set Vessel Bypass Valves to direct well returns directly into flow line.
2. Power Cleaning Unit – OPEN Valves CS-1, CS-2 and CS-3, PLUS Valves R-1, R-2, R-3 and R-4.
3. Wellhead Control – OPEN Valves W-1, W-2 and W-3. Be sure Lever Operator W-4 is locked in a horizontal position.

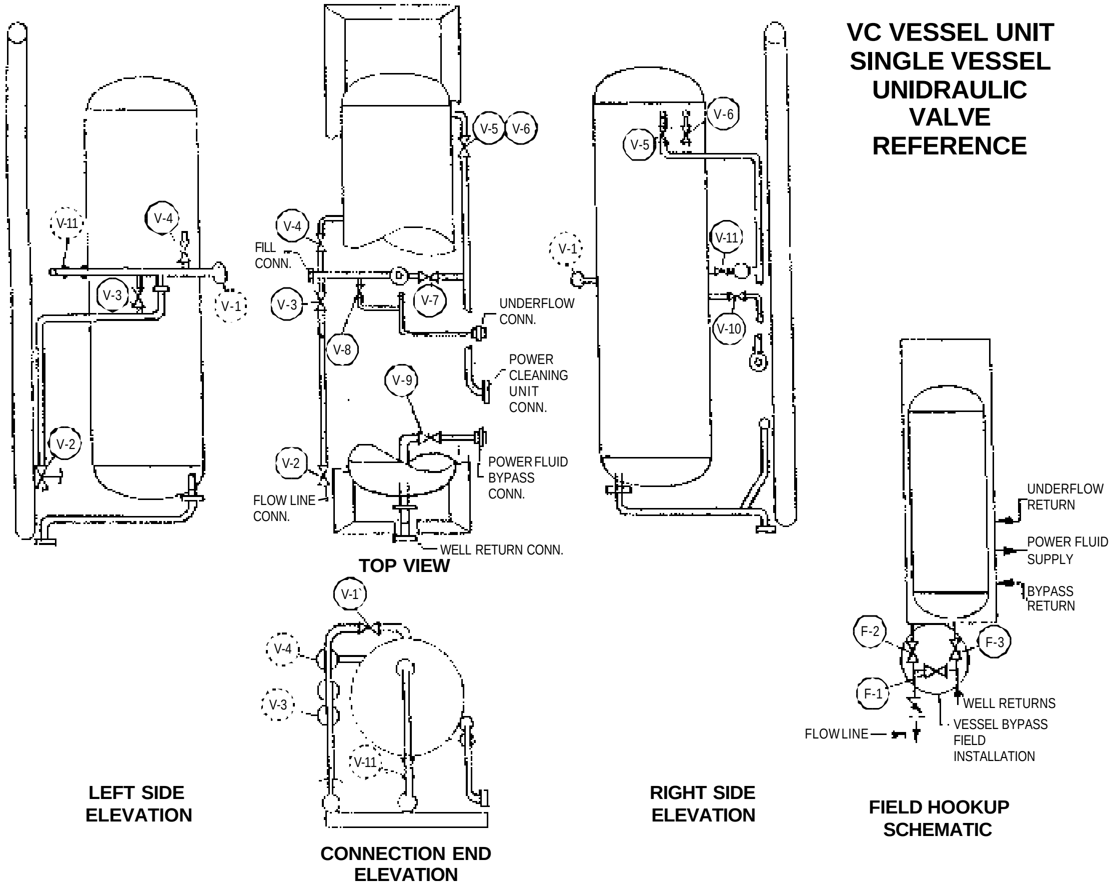
Be certain a continuous supply of fluid is being supplied to the vessel and start the Triplex Pump. With the pump operating, check position of the differential pressure controlled suction shut-in Valve CS-4 to be certain it is in OPEN position. If it remains closed, close Valve R-4 and slowly open Valve R-5 to bleed pressure from above the diaphragm of Valve CS-4. When Valve CS-4 remains open, CLOSE Valve R-5 and OPEN Valve R-4.

During this circulation stage, the power fluid line to the well may be tested for leaks and the Triplex Relief Valve set to its operating setting.

CAUTION – This procedure must be done with care to avoid serious injury or damage to the equipment.

1. Set High Discharge Pressure Switch in the Safety Shut-Down Panel to shut down triplex at a pressure no more than 10% over the Triplex pressure rating for the size plungers installed.





2. Slowly close the Wellhead Bypass Valve W-3. Adjust the Triplex Relief Valve to the proper setting. Adjust the relief valve opening pressure by loosening the jam nut and turning the adjusting screw <u>clockwise</u> to <u>increase</u> pressure or <u>counter-clockwise</u> to <u>reduce</u> pressure. Set the opening pressure <u>at</u> the Triplex pressure rating for the size plungers installed. If the Relief Valve opens before the desired pressure setting is reached, it is necessary to bleed discharge pressure to less than half of the relief valve opening pressure to re-close the valve. This can be accomplished by opening the discharge bypass valve at the Triplex of the Wellhead Bypass W-3 at the Wellhead.

   After these settings are made, pressure up the flow line, shut down the Triplex and check lines for leaks. Reopen Wellhead Valve W-3.

   Circulation through this route should be continued until the flow line and all equipment upstream of the stock tank is filled. This will be accomplished when circulated fluid is being discharged into the stock tank. If available fluid supply limits this volume of circulation, the minimum circulation should be sufficient to displace the surface lines through the flow line check valve downstream of the Unit flow line connection.

Well System Circulation

After minimum circulation of surface lines has been completed, proceed to this stage. Before this circulation path is established, the retrievable standing valve must be run into the tubing. Fluid is to be circulated into the tubing before dropping the standing valve.

1. Set Wellhead Control Lever W-4 in the Pump-in position (lever downward) and CLOSE wellhead bypass valve W-3. Valves W-1 and W-2 should be OPEN.
2. Start Triplex and circulate about twenty (20) barrels of power fluid into the tubing.
3. Open Wellhead Bypass valve W-3 and shift Wellhead Control Lever W-4 to shut-off (lever horizontal). Open bleed valve on Wellhead swivel block to bleed all pressure from tubing.

   CAUTION: Do not proceed until all pressure is relieved from tubing.
4. Remove Wellhead Catcher by loosening the lugged union nut.
5. Drop Retrievable Standing Valve into tubing. Be certain pump seat is at top of the standing valve. Replace union nut on wellhead and tighten.
6. Return Wellhead Control Lever W-4 to Pump-in (lever downward) and CLOSE bypass valve W-3.

After the Retrievable Standing Valve has landed in its seat in the Bottom Hole Assembly, the system is set for continued well circulation. The most desirable well circulating course will direct fluid down the production return string (casing annulus or parallel tubing) and up the power fluid tubing. This minimizes the possibility of depositing solids on top of the retrievable standing valve.

To establish this course, shift the Wellhead Control Lever W-4 to the PUMP OUT position (lever upward), then slowly CLOSE the Wellhead Control Bypass valve W-3. No changes in valve settings on the Unit are required.

Circulation in this mode should be continued to fill, then completely displace the volume of well tubulars (power fluid tubing AND casing annulus or parallel tubing).

If available fluid supply limits this volume of circulation in a casing free installation, and tubulars are known to be relatively clean, it may be satisfactory to follow an alternate tubular circulation procedure. For this alternate course, shift the Wellhead Control Lever W-4 to the PUMP-IN position (lever downward) before closing the Wellhead Control Bypass valve W-3. This setting circulates fluid down the power fluid tubing and up the casing annulus. In this mode, minimum circulation should completely displace the volume of the power fluid tubing to flush solids out of the tubing and into the casing annulus.

Complete System Circulation

After circulating well tubulars, circulation through the vessel can be established and the complete system circulated through the path of normal operation.
CLOSE Vessel Bypass valve F-1.
OPEN Vessel Flow Line valve F-2 and Vessel Well Returns valve F-3.

During this circulating stage, the Vessel Flow Line Back Pressure Valve V-2 can be adjusted to open at a minimum of 60 psi. This valve will later be adjusted to a pressure setting 10 psi over the highest anticipated flow line pressure or a minimum of 60 psi.

Also during this circulation stage, the pre-set pressure controls may be checked for correct operation. A separate gauge and four-position valve is provided in a panel for convenient and reliable read-out of the differential pressures established by these controls. Refer to <u>Cleaning System Pressure Read-Out</u> heading in this section for this procedure.

If the well is equipped with a packer for a casing free installation, the packer can be pressure tested during this circulation stage.

CAUTION: Be certain that pressure applied to the packer and casing does not exceed the pressure capacity of this equipment.

1. Set High Discharge Shut-Down Switch to maximum pressure to be used in testing the packer. This should not exceed 1500 psi.
2. Set Wellhead Control Lever W-4 to the Pump-In position (lever downward) and the Bypass Valve W-3 CLOSED.
3. Shut-off the casing annulus by closing wellhead flow line valve W-2.
4. When the Triplex is shut down at the set pressure, CLOSE power fluid supply valve W-1 and hold pressure on the packer for about ten (10) minutes to confirm it is holding.
5. Re-open valves W-1 and W-2.

After completing these procedures, the system can be prepared for normal operation. Check fluid level in vessel. The level should be approximately at the level of the upper connection on the gravity dump leg (above valve V-3). When level is adequate, the fluid supply source can be disconnected.

1. CLOSE valves V-10 and V-11.
2. Disconnect supply line and cap fill connection.
3. OPEN valves V-10 and V-11.

INSTALLATION OF DOWNHOLE PUMP AND SYSTEM START-UP

When all of the preceding start-up procedures have been accomplished, the system will be ready for installation and starting of the downhole pump.

Install Downhole Pump

Remove the catcher assembly from the wellhead control and attach to the fishing neck of the swab nose assembly on the top of the pump. Be certain the catcher slip release nut is screwed down tightly to securely latch the pump into the catcher slips. Lower the pump into the wellhead control and make up the catcher union nut tightly to secure the catcher to the wellhead control. With the pump still hanging in the catcher, prepare to restart the multiplex pump.

Set the lever operator on the wellhead control in the PUMP-IN position (lever downward), OPEN the wellhead control bypass, and check inlet and outlet valves to be certain they are OPEN.

Restart PFCU Multiplex Pump

It the PFCU is equipped with a manual operated discharge bypass choke valve on the multiplex discharge – normally used with a downhole positive displacement pump – adjust this bypass valve to a HALF OPEN position before starting the multiplex.

If the unit is equipped with a pressure operated discharge bypass pressure control – normally used with a downhole jet pump – adjust this valve or a reduced pressure setting by loosening the lock nut and backing out the spring adjusting screw two turns before starting the multiplex.

Recheck the valve position guide on Page 12 to be certain all valves are properly set.

The multiplex may now be restarted to establish circulation from the unit to the well. CLOSE the wellhead bypass valve and circulate fluid into the well for about ten minutes before releasing the unit. Do this by backing off (counter-clockwise) the slip releasing nut on the wellhead catcher assembly. Continue circulating fluid into the well to circulate the pump to bottom.

It is good practice to reduce the circulation rate into the well as the pump nears bottom by opening the wellhead bypass. This will slow the travel speed of the pump as it enters the bottom hole cavity. When the pump is seated in the cavity, operating pressure will increase and the wellhead bypass can be CLOSED.

Set the operating speed of the downhole positive displacement pump at the desired rate by adjusting the discharge bypass choke valve.

Set the operating pressure of the downhole jet pump by adjusting the discharge bypass pressure control to the desired pressure.

After the system reaches a stabilized pumping condition, recheck the vessel fluid levels and pressures and make necessary adjustments for optimum performance.

Re-check the settings on the suction and discharge hi-low safety switches in the shut-down panel and adjust to following settings:

Suction Shut-Down Switch

High	30 psi over reservoir vessel back pressure Valve setting
Low	60 psi under high shut-down setting

Discharge Shut-Down Switch

High	200 psi over operating pressure maximum setting at pressure rating of plunger size In multiplex pump
Low	500 psi under high shut-down setting

Re-check multiplex relief valve and set opening pressure as the final safety relief in the discharge system. Adjust the opening pressure by loosening the jam nut and turning the adjusting screw clockwise to increase pressure or counter-clockwise to reduce pressure. The relief valve should be set to open at 300 psi over the setting of the high pressure shut-down on the discharge shut-down switch. Maximum opening pressure should not exceed 3500 psi on the MCA medium pressure fluid end or 4500 psi on the HCA high pressure fluid end.

After Storage Start-Up

For start-up procedure after periods of storage of the PFCU, see the Preventative Maintenance Section of this manual.

Final Equipment Check

All valving in the system should be given a final check for correct settings. Refer to Page 11.
Vessel Unit – Valve settings differ slightly to preferentially reserve oil or water for use as power fluid. These differences are noted in the following tabulation of proper initial operating settings for all valves.

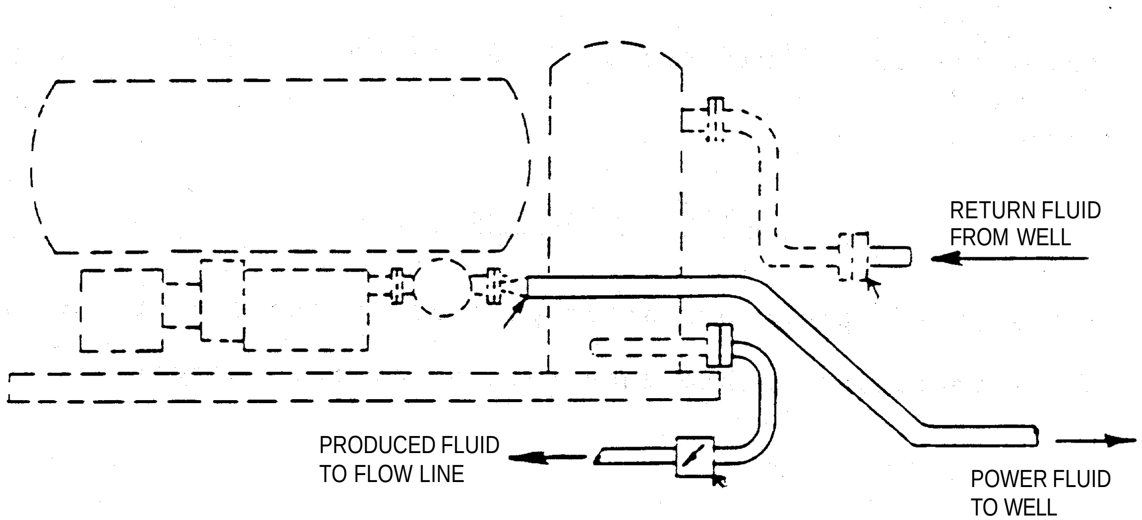
Valve	Valve Settings		
Reference	Either P.F.	Power Oil	Power Water
F-1	Closed	--	--
F-2	Open	--	--
F-3	Open	--	--
V-1	Open	--	--
V-2	Press. Controlled	--	--
V-3	Closed	--	--
V-4	--	Closed	Open
V-5	Open	--	--
V-6	Closed	--	--
V-7	Closed	--	--
V-8	--	Closed	Open
V-9	Check Valve	--	--
V-10	--	Open	Closed
V-11	--	Open	Closed

Power Cleaning Unit and Wellhead

All valve settings are the same for operation on either power oil or power water. Refer to Page 12.

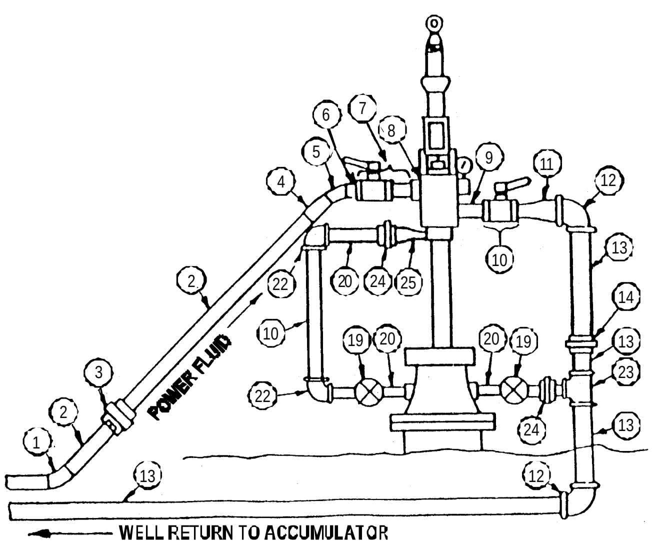
CS-1	Open
CS-2	Open
CS-3	Open
CS-4	Pressure Controlled
CS-5	Pressure Controlled
R-1	Open
R-2	Open
R-3	Open
R-4	Open
R-5	Closed
W-1	Open
W-2	Open
W-3	Closed
W-4	Pump-In

PLUMBING GUIDE -- PFCU

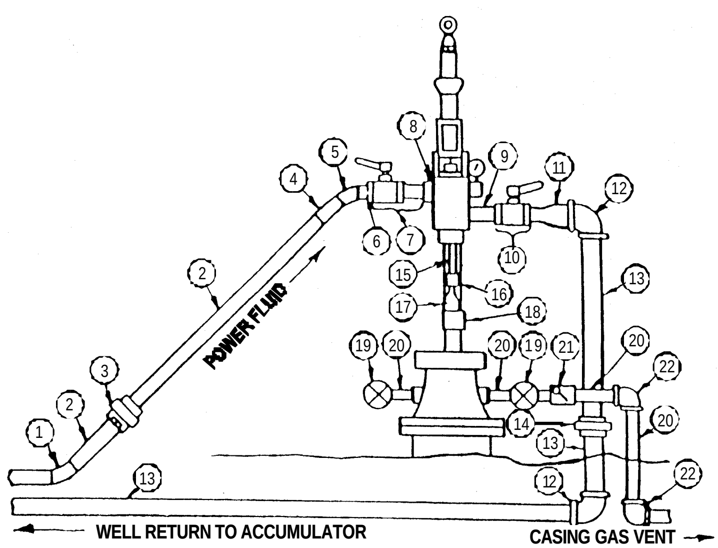


1 **2” Sch. 160 BFW** 2 **3” 150# R.F. Flange** 3 **3” Check Valve**

Item No.	Description	No. Req'd. (PF)	No. Req'd. (CF)		Item No.	Description	No. Req'd. (PF)	No. Req'd. (CF)
1	2" or 2-1/2" 45° Weld Ell	1	1		14	3" Hammer Union	1	1
2	2-3/8" or 2-7/8" Tubing	2	2		15	1-1/4" Nipple	1	0
3	2" or 2-1/2" Unibolt Coupling	1	1		16	1-1/4" Coupling	1	0
4	2" x 2-1/2" Weld Reducer	(1 Optional)			17	2-3/8" x 1-1/4" Swage	1	0
5	2" 45° Weld Ell	1	1		18	2-3/8" Coupling	1	0
6	Flange Assembly (510-023)	1	1		19	2" Gate Valve	2	2
7	1-1/2" Ball Valve	1	1		20	2" Nipple	5	7
	Consisting of:				21	2" Check Valve	1	0
	1 510-018 Body Group				22	2" Ell	2	2
	1 180-440 Flange				23	3" x 3" Tee	0	1
	1 180-480 Ring				24	2" Hammer Union	0	2
	4 180-054 Screw				25	2" x 1" Swage	0	1
	1 502-134 Tube							
8	Wellhead Control Assembly (280-374)	1	1					
9	2" x 6" XXH Nipple	1	1					
10	2" Ball Valve (500-016)	1	1					
11	2" x 3" Swage Nipple	1	1					
12	3" Ell	2	2					
13	3" Line Pipe	3	3					



CASING FREE



PARALLEL FREE

Before Start-Up Check List

3. VESSEL

_______ A. Check base bolts for tightness on both tanks
_______ B. Check all flange bolts
_______ C. Check sight glass seals for tightness
_______ D. Check cyclone connection and manway bolts
_______ E. Check all brace "V" bolts to assure tightness
_______ F. Check all valves for proper setting.
See start-up instructions

4. TRIPLEX

_______ A. Check base bolts for tightness
_______ B. Check valve caps for tightness
_______ C. Check flange bolts for tightness
_______ D. Check oil level in Triplex power end
_______ E. Check oil level in gear reducer and transmission
_______ F. Check oil level in lubricator
_______ G. Check oil level in chemical pump
_______ H. Check operation of oil level switches on high and low settings and tattletales. Set oil level switch settings.
_______ I. Pump up lubricator lines for lubrication
_______ J. Check hose connections to Shut-Down panel for tight connections. Hoses must not contact sharp edges.
_______ K. Check operation of Suction and Discharge Hi-Low Safety Switches in Shut-Down panel. Set shut-down contacts for start-up protection as follows on the next page.

Suction Shut-Down Switch

______ High 30 psi higher than anticipated flow line pressure, 125 psi maximum

______ Low 30 psi lower than anticipated flow line pressure

Discharge Pressure Shut-Down Switch

______ High 200 psi higher than anticipated operating pressure. Maximum at pressure rating of plunger size in multiplex pump

______ Low 300 psi lower than anticipated flow line pressure

______ L. Spray all kill switch electrical connections with liquid weather proofing

______ M. If electric, start chemical pump and pump into triplex suction before start-up. Check rotation for proper direction

______ N. Check flexible coupling alignment and couple. Or belt drive alignment and belt tension

PRIME MOVER

ELECTRIC MOTOR

______ A. Check base bolts for tightness

______ B. Check rotation for proper direction

MULTI-CYLINDER ENGINE

______ A. Check fluid levels in radiator and crankcase

______ B. Check fuel supply and set regulator

______ C. Check base bolts for tightness

______ D. Check alignment of coupling

______ E. Check kill switch “hook-up” to magneto

Trouble-Shooting Procedure

To minimize maintenance costs on surface and subsurface equipment, it is important that the operation of the power fluid conditioning unit be checked at regular intervals and corrective action taken when improper operation is detected.

Following is a check list of four maintenance items which should be regularly monitored. In addition is a list of five possible problems which may be encountered with probable cause and solution as a trouble-shooting guide. In each of these lists, page references are noted where applicable, referring to the INSTALLATION and START-UP INFORMATION section of this manual which contains additional related information.

Check for Proper Operation – To determine if the PFCU is operating properly, the following items should be regularly monitored:

1. **Fluid Level in Vessels** – Both accumulator and reservoir vessels should be checked for proper fluid level.
   Reference: Page 10.

2. **Cyclone Underflow** – It is essential that the cyclone underflow be operating continuously. The flow indicator or sight glass should be checked to determine this.
   Reference: Pages 7, 8 and 9.

3. **Vessel Pressures** – The pressure levels should be checked to determine that they are within prescribed limits. (Normally, the reservoir vessel should be approximately 10 psi above flow line pressure, and the accumulator should be 30 to 50 psi above the reservoir pressure).
   Reference: Pages 7 and 8, 11 and 12.

Note: Accurate and reliable pressure gauges are needed for these checks

4. **Level of Oil** – Water Interface in Reservoir – The level of oil-water interface in the reservoir vessel should be kept as far from the power fluid discharge level as practical. When making this check it is good practice to vent the sight glass through the valve provided.
   Reference: Page 12.

If the system is not operating properly, corrective action should be undertaken as indicated in the Trouble-Shooting Guide.

TROUBLE-SHOOTING GUIDE

Problem	Solution
1. Insufficient fluid in accumulator	Too much fluid may be discharging through the cyclone. Reduce differential pressure between vessels by backing out adjustment on Accumulator Differential Pressure valve (do not adjust lower than 30 psi differential) or re-size cyclone feed nozzle to reduce feed rate. See Problem 4. Reference: Pages 11, 12 & 13.
2. Insufficient fluid reservoir vessel	Too little fluid may be entering from the cyclone. Increase differential pressure between vessels by turning in adjustment on Accumulator Differential Pressure valve (do not adjust higher than 50 psi difference) or re-size cyclone trim to increase feed rate. See Problem 4. Reference: Pages 11, 12 & 13. Check cyclone underflow for excess flow. Reference: Page 9. Be certain that valves V-6 and V-7 are not both open at the same time. Reference: Page 10.
3. Water building in reservoir vessel when attempting to operate with power oil	This indicates too much oil is being lost from the cyclone underflow or that the vessel underflow valves are not properly set. Reduce cyclone underflow rate and check that valves V-2 and V-9 are open. Reference: Pages 9 & 10.
4. Loss of fluid in system	4a. This can be caused when the system is shut down and valves V-6 and V-7 are both open. Always make certain one of these valves is closed. Reference: Pages 9 & 10.

TROUBLE-SHOOTING GUIDE (Cont'd.)

Problem	Solution
4. Loss of fluid in system (cont'd.)	4b. During shut-down, the Accumulator Vessel will drain to the flow line if valve V-6 is OPEN. If operating with V-6 OPEN and V-7 CLOSED, during any planned shut-down, valve V-6 should be closed for the duration of shut-down. Be sure to re-open when Unit is re-started.
	4c. Some wells have a tendency to head off with slugs of gas and fluid. When this occurs with a casing return system, there may not be sufficient fluid in the PFCU to refill the casing and the system will shut down due to low discharge pressure (loss of fluid). This can frequently be overcome by restricting return flow from the well with an adjustable choke at the wellhead. If this is not successful, more reservoir capacity is needed
5. Unit shut-down by Shut-down controls due to:	
a. High discharge pressure	5a Possibly caused by:
	5a. 1. Shut-down safety switch high pressure contact set too close to normal pressure. Check setting. Reference: Page
	5a. 2. Any blockage in the well, Unit or flow line system. Recheck all valve settings.
	5a. 3. Malfunction of Discharge Bypass Choke Valve or Pressure Controller. Adjust bypass or inspect and repair if necessary.
	5a. 4. Downwell positive displacement pump may have stopped stroking due to sticking. If unable to restart downhole pump, circulate to surface for inspection.
	5b. 2. Loss of fluid in Reservoir Vessel resulting in fluid starved suction to Multiplex Pump and reduced discharge pressure. See Items 2 and 4 of Trouble-Shooting Guide.

TROUBLE-SHOOTING GUIDE (Cont'd.)

Problem	Solution		
5b. Low Discharge Pressure	5b.	1.	Shut down safety switch low pressure contact set too close to normal operating pressure. Check setting.
	5b.	2.	Loss of fluid in Reservoir vessel resulting in fluid starved suction to multiplex pump and reduced discharge pressure. See Items 2 and 4 of Trouble Shooting Guide.
	5b.	3.	Failure of high pressure safety switch to shut down unit. Multiplex Relief Valve would open at pre-set high pressure, then bleed off to minimum pressure which should be lower than setting of low pressure shut-down contact. Relief valve closes when pump shuts down. Recheck safety switch.
	5b.	4.	Any cause of loss of pressure in surface discharge lines or in subsurface circuit. Restart Unit and check discharge pressure build-up.
5c High suction pressure	5c.	1.	Shut-down safety switch high pressure contact set too close to Reservoir Back Pressure valve setting. Recheck settings. Reference: Page 14.
	5c.	2.	Any cause of high Reservoir pressure. If Back Pressure valve is operating properly, check for any restriction in flow line down stream of Unit.
5d. Low suction pressure	5d.	1.	Shut-down safety switch set too close to normal Reservoir pressure. Recheck setting. Reference: Page 14.
	5d.	2.	Any cause of loss of pressure in Reservoir below proper setting of low pressure shut-down. Restart system and check Reservoir pressure.

UNIDRAULIC PREVENTATIVE MAINTENANCE SCHEDLE

Daily Maintenance

1. Check lube oil levels in both Triplex and Gear Reducer. (This can be done by checking level in safety switch gauges).

2. Check lubricator for proper level and operation.

3. Check plungers for excessive leakage.

4. Check stuffing box nut for tightness.

5. Check plunger chamber drain line, making sure it is clear of obstructions.

6. Drain plunger leakage sump tank is required.

7. Check underflow on bottom of cyclone.

8. Check pump for any abnormal vibration or noise. (See items 3 and 4 under Weekly Maintenance).

9. Check fluid in vessel for proper level.

Weekly Maintenance

1. Check lube oil levels by shutting unit down and checking with dip stick at back of pump, and check plug on side of gear reducer case. Inspect oil for contamination and change if necessary.

2. Check and test High-Low oil level safety switches for proper operation.

3. If Multiplex pump is equipped with Fluid Seal Plungers, remove plunger clamps and check plunger mandrel for looseness. If loose, remove plunger and tighten or replace mandrel cap screw.

4. Check pump while running for any abnormal noise or vibration in fluid cylinder. (if any, recheck item 3 or pull and check valves for washed seals or bad valves).

5. Check for leaks between fluid cylinder and frame or stuffing box and frame (if found, replace stuffing box seal).

UNIDRAULIC PREVENTATIVE MAINTENANCE SCHEDULE (Cont'd.)

Monthly Maintenance

1. Drain and refill crankcase on Triplex and gear reducer every six months, or as often as required to maintain a clean sludge free lube oil of the proper viscosity.

2. Clean crankcase air breather with non-explosive solvent.

3. Check all studs, nuts and capscrews for tightness.

4. Inspect Falk Coupling for proper lubrication. Add grease if necessary.

5. Check rotation of Triplex on start-up electric motor.

Storage

If the pump is to be idle for longer than one week, it should be prepared for storage as follows:

1. Drain and clean crankcase thoroughly. Leave drain open and install 90° elbow, pointing downward, to permit air circulation and prevent condensation build-up

2. Coat all bearings, finished surfaces, and entire inside surface of crankcase with a rust inhibiting oil.

3. Remove plungers and packing; clean and coat with rust inhibiting oil.

4. Remove fluid cylinder valves allowing cylinder to be thoroughly cleaned and drained.

5. Coat entire cylinder, valves and parts, with a rust inhibiting oil.

6. Thoroughly inspect pump and rotate crankshaft once a month. Recoat with rust inhibiting oil where necessary.

UNIDRAULIC PREVENTATIVE MAINTENANCE SCHEDULE (Cont'd.)

Start-Up After Storage

Any pump that has been in storage, either after field use or as shipped from the plant, will need a thorough inspection to make sure it has not been damaged in any way and that all parts are properly in place.

Failure to observe the following points can result in serious damage:

1. Remove all covers on both power end and fluid end; thoroughly clean and inspect all parts and finished surfaces.

2. Check all bearings to make sure they are clean and in good condition.

3. Make sure valves, plungers and packing are properly installed and in good condition.

4. Carefully tighten all bolts, nuts, studs and working connections.

5. Fill power end to the proper level with clean oil of the proper viscosity. Make sure oil is poured into the crosshead reservoir and is worked into all bearings.

6. Fill packing lubricator and pump lines. Check by breaking connection at stuffing box, working lubricator plunger until oil appears.

OILMASTER WELLHEAD CONTROL VALVE

Features of the Weatherford Oilmaster Wellhead Control Valve

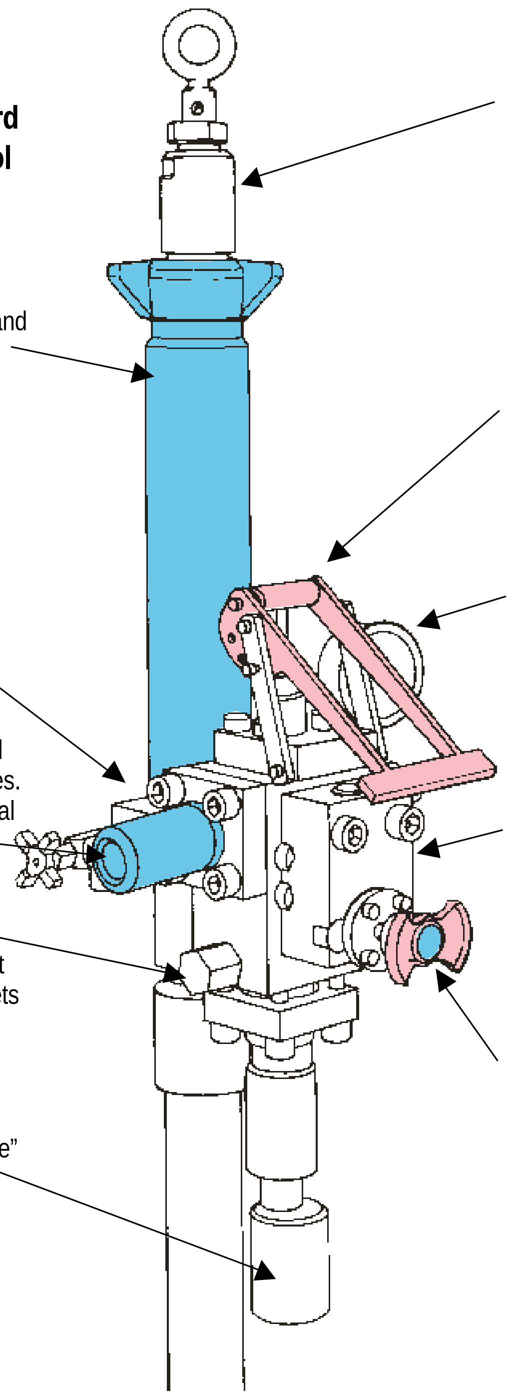
Extended Catcher Nipple. This allows bleeding of pressure and gas out of tubing before removing the pump.

Swivel Block Design. 360° rotation gives maximum flexibility in aligning control assembly with connecting lines during hookup.

Large Fluid Passages. Inlets and outlets allow high volume flow rates. Welded or threaded ends in several sizes are available.

Pressure Relief Valve. Protects well tubulars against excessive pressure build-up during pump-out cycle. Opens at 1500 psi and resets automatically when pressure is relieved.

Choice Of Inlet Connections. Flanged inlet nipple for casing "free" installations. Slip joint connection with adjustable offset for parallel installation.



Pump Catcher For Easy Retrieval. When ready for change out, just shift the lever and the downhole "free" pump will flow to the surface where the indicator announces pump arrival. The unit will latch in the catcher unattended and without pressure build-up.

4-Way Lever Control. Swift and easy actuation. Valve has three positions; pump-in and operate, bypass and pump-out.

Pressure Gauge. With pulsation dampener, shows the circulating pressure and pump strokes. Lets your pumper know just what is happening downhole.

Low Maintenance Valve. Rugged design with few wearing parts. Replaceable elements include stainless steel sleeve and seat and metal sprayed spool.

Power Fluid Bypass. Stops high pressure accumulation at wellhead during pump removal. Controls the pressure setting when quick changes of flow direction are needed to unseat the downhole pump. Gives shock-free reversal of fluid flow direction. Eliminates expensive extra plumbing.

OILMASTER PRESSURE CONTROLLER

SUBSURFACE TROUBLESHOOTING GUIDE – RECIPROCATING PUMP

INDICATION	CAUSE	REMEDY
Sudden increase in operating pressure – pump stroking	(a) Lowered fluid level, which causes more net lift. (b) Paraffin build-up or obstruction in power oil line, flow line, or valve. (c) Pumping heavy material, such as salt water or mud. (d) Pump beginning to fail.	(a) If necessary, slow pump down. (b) Run soluble plug or hot oil, or remove obstruction. (c) Keep pump stroking – do not shut down. (d) Retrieve pump and repair.
Gradual increase in operating pressure – pump stroking	(a) Gradually lowering fluid level. Standing valve or formation plugging up. (b) Slow build-up of paraffin. (c) Increasing water production.	(a) Surface pump and check. Retrieve standing valve. (b) Run soluble plug or hot oil. (c) Raise pump strokes/min. and watch pressure.
Sudden increase in operating pressure – pump not stroking	(a) Pump stuck or stalled. (b) Sudden change in well conditions requiring operating pressure in excess of triplex relief valve setting. (c) Sudden change in power oil emulsion, etc. (d) Closed valve or obstruction in production line.	(a) Alternately increase and decrease pressure. If necessary, unseat and reseat pump. If this fails to start pump, surface and repair. (b) Raise setting on relief valve. (c) Check power oil supply. (d) Locate and correct.
Sudden decrease in operating pressure – pump stroking. (Speed could be increased or reduced).	(a) Rising fluid level – pump efficiency up. (b) Failure of pump so that part of power oil is bypassed. (c) Gas passing through pump. (d) Tubular failure – downhole or in surface power oil line. Speed reduced. (e) Broken plunger rod. Increased speed. (f) Seal sleeve in BHA washed or failed. Speed reduced.	(a) Increase pump speed if desired. (b) Surface pump and repair. (d) Check tubulars. (e) Surface pump and repair. (f) Pull tubing and repair BHA.
Sudden decrease in operating pressure – pump not stroking	(a) Pump not on seat. (b) Failure of production unit or external seal. (c) Bad leak in power oil tubing string. (d) Bad leak in surface power oil line. (e) Not enough power oil supply at manifold.	(a) Circulate pump back on seat. (b) Surface pump and repair. (c) Check tubing and pull and repair if leaking. (d) Locate and repair (e) Check volume of fluid discharged from triplex. Valve failure, plugged supply line, low power oil supply, excess bypassing, etc., all of which could reduce available volume.
Drop in production – pump speed constant	(a) Failure of pump end of production unit. (b) Leak in gas vent tubing string. (c) Well pumped off – pump speeded up. (d) Leak in production return line. (e) Change in well conditions. (f) Pump or standing valve plugging. (g) Pump handling free gas.	(a) Surface pump and repair. (b) Check gas vent system (c) Decrease pump speed (d) Locate and repair. (f) Surface pump and check. Retrieve standing valve. (g) Test to determine best operating speed.
Gradual or sudden increase in power oil required to maintain pump speed. Low engine efficiency.	(a) Engine wear. (b) Leak in tubulars – power oil tubing, BHA seals, or power oil line.	(a) Surface pump and repair. (b) Locate and repair.
Erratic stroking at widely varying pressures.	(a) Caused by failure or plugging of engine.	(a) Surface pump and repair.
Stroke "downkicking" instead of "upkicking".	(a) Well pumped off – pump speeded up. (b) Pump intake or downhole equipment plugged. (c) Pump failure (balls and seats). (d) Pump handling free gas.	(a) Decrease pump speed. Consider changing to smaller pump end. (b) Surface pump and clean up. If in downhole equipment, pull standing valve and backflush well. (c) Surface pump and repair.
Apparent loss of, or unable to account for, system fluid.	(a) System not full of oil when pump was started due to water in annulus U-tubing after circulating, well flowing or standing valve leaking. (b) Inaccurate meters or measurement.	(a) Continue pumping to fill up system. Pull standing valve if pump surfacing is slow and cups look good. (b) Recheck meters. Repair if necessary.

CALCULATING PUMP EFFICIENCIES

Engine End Efficiency =

SPM x Engine End Displacement Factor / Actual Metered Power Fluid Rate	***OR***	35 SPM x 6.4 (F201611) = 224 (100%) / 298 (75%)

Pump End Efficiency =

Actual Metered Production Rate / SPM x Pump End Displacement Factor	***OR***	97 BPD / 35 SPM x 3.00 (F201611) = 105 = 92%

**SPM = Strokes Per Minute

CALCULATING PUMP EFFICIENCIES

$$\frac{\textbf{Stroking or/Slow Stroking } \textit{Pressure (1800 PSI)}}{\textbf{Fluid Gradient} \quad \textbf{x P/E}} = \textbf{Lift Depth}$$

(.433 Freshwater) *(.47 F201611)*

.20351

8844.77 Ft.

Fluid Gradient X Pump Depth --- $\dfrac{\textbf{Stroking or/ Slow Stroking Pressure = } \textit{1800 PSI}}{\textbf{P/E = } \textit{.47}}$ = **Pumping Bottom Hole Pressure =**

.433 x 9000 Ft. = 3897   *3829*   *68 PSI*

STROKE COUNTING FOR PISTON PUMPS

To calculate strokes per minute on hydraulic piston pumps, use the following method:

1. Use a stopwatch to determine how long it takes for the pump to make 25 full strokes. The first stroke counted should be as "0". Remember that the Kobe pump is double acting and that there are two kicks to every full stroke. The Oilmaster pump is single acting and every kick indicates a full stroke.

2. Divide 1500 by the number of seconds that it took to make the 25 strokes.

$$\frac{\text{1500 (Constant)}}{\text{\# of Seconds For 25 Strokes}}$$

If for instance the pump makes 25 strokes in 25 seconds, the stroke would be calculated as follows:

$$\frac{\text{1500 (Constant)}}{\text{25 Seconds}}$$

This would equal a stroke rate of 60 strokes per minute.

If the pump made 25 strokes in 46 seconds the stroke would be calculated as follows:

$$\frac{\text{1500 (Constant)}}{\text{46 Seconds}}$$

This would equal a stroke rate of 32.6 SPM.

This method of stroke counting works equally well for the Kobe double acting pumps and the Oilmaster single acting pumps.

MISCELLANEOUS CALCULATIONS AND FORMULAS

Calculating GOR

To calculate the GOR for a well, take the total gas production in MCF (thousand standard cubic feet) and divide the measured MCF by the net oil production.

Example: On a well that produces 200 BPD at a 80% water cut that makes 11 MCF (11,000 standard cubic feet) the GOR would be calculated as follows:

Net Oil production = 40 BPD (80% of 200 BPD)
Measured gas volume = 11 MCF (11,000 standard cubic feet)

Divide 11,000 by 40 = GOR of 275

Horsepower Calculations

To calculate Hydraulic Horsepower (HHP):

Rate (BPD) X Pressure (PSI) X .000017 – HHP
(1877 BPD x 2750 PSI x .000017 = 97.49 HHP)

HHP divided by .9 = required input horsepower to triplex = 108.3

Required triplex input horsepower divided by .9 = Brake Horsepower (BHP) required at the input shaft of the triplex. This is the horsepower required for sizing the prime mover.

Or, you can take the calculated HHP and multiply by 1.2345678 to get the required HP at the input shaft of the pump.

MISCELLANEOUS CALCULATIONS AND FORMULAS

Productivity Index (PI) Calculations

To draw PI (Productivity Index) lines:

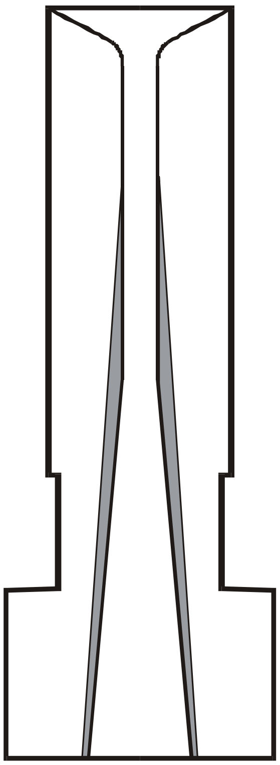
Production Rate (BPD) divided by PI = Drawdown (DD)
Static Bottom Hole Pressure (SBHP) – DD = Pump Intake Pressure (PIP)
Arriving at PI from SBHP:
SBHP – PIP = DD
Production Rate (BPD) divided by the DD = PI

Displacement Calculations

Plunger Area squared X Stroke Length X # of Cylinders X RPM
Divided by 231 = Gallons Per Minute (GPM).
Diameter squared X .7854 = Plunger Area
Example for 1-1/2" plunger: 1.5 X 1.5 X .7854 = 1.76715
To arrive at BPD after calculating GPM:
Multiply GPM X 1440 and divide by 42 = BPD displacement

SUBSURFACE TROUBLESHOOTING GUIDE – JET PUMPS

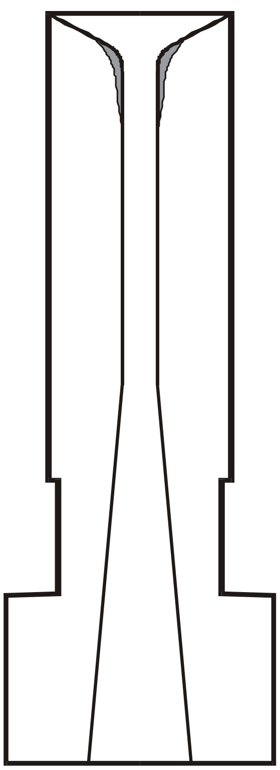
INDICATION	CAUSE	REMEDY
Sudden increase in operating pressure – pump taking power fluid.	(a) Paraffin build-up or obstruction in power oil line, flow line, or valve. (b) Partial plug in nozzle.	(a) Run soluble plug or hot oil, or remove obstruction. Unseat and reseat pump. (b) Surface pump and clear nozzle.
Slow increase in operating pressure – constant power fluid rate or slow decrease in power fluid rate, constant operating pressure.	(a) Slow build-up of paraffin. (b) Worn throat or diffuser	(a) Run soluble plug or hot oil. (b) Retrieve pump and repair.
Sudden increase in operating pressure – pump not taking power fluid.	(a) Fully plugged nozzle.	(a) Retrieve pump and clear nozzle.
Sudden decrease in operating pressure – power fluid rate constant or sudden increase in power fluid rate, operating pressure constant.	(a) Tubular failure. (b) Blown pump seal or broken nozzle.	(a) Check tubing and pull and repair if leaking. (b) Retrieve pump and repair.
Drop in production – surface conditions normal.	(a) Worn throat or diffuser. (b) Plugging of standing valve or pump. (c) Leak or plug in gas vent. (d) Changing well conditions.	(a) Increase operating pressure. Replace throat and diffuser. (b) Surface pump and check. Retrieve standing valve. (c) Check gas vent system. (d) Run pressure recorder and resize pump.
No production increase when operating pressure is increases.	(a) Cavitation in pump or high gas production. (b) Plugging of standing valve or pump.	(a) Lower operating pressure or install larger throat. (b) Surface pump and check. Retrieve standing valve.
Throat worn – one or more dark, pitted zones.	(a) Cavitation damage.	(a) Check pump and standing valve for plugging. Install larger throat. Reduce operating pressure.
Throat worn – cylindrical shape worn to barrel shape, smooth finish.	(a) Erosion wear.	(a) Replace throat. Install premium material throat. Install larger nozzle and throat to reduce velocity.
New installation does not meet prediction of production.	(a) Incorrect well data. (b) Plugging of standing valve or pump. (c) Tubular leak. (d) Side string in parallel installations not landed.	(a) Run pressure recorder and resize pump. (b) Check pump and standing valve. (c) Check tubing and pull and repair if leaking. (d) Check tubing and re-stab if necessary.



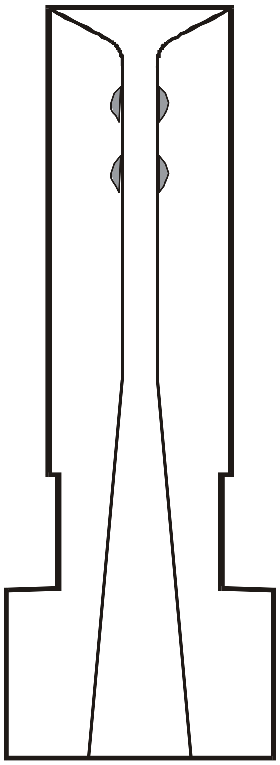
SUBSURFACE TROUBLESHOOTING GUIDE – JET PUMPS

Examples of Throat Wear

Example "A"
Erosion from sand normally occurs in a long enlarged area from the entrance end of the throat into the diffuser section of the throat.



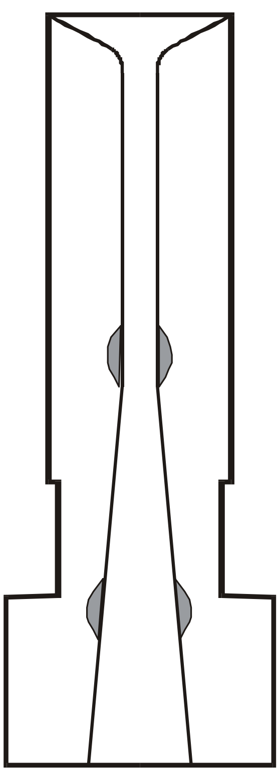
Example "B"
Entrance end of throat enlarged, usually caused from trying to produce more than the annular area will accommodate. Also, choking from large volume of gas.



SUBSURFACE TROUBLESHOOTING GUIDE – JET PUMPS

Examples of Throat Wear

Example “C”
Cavitation in the entrance of the throat is cavitation from produced fluid. Need to go to the next larger size throats.



Example “D”
Cavitation in the lower end of the throat and into the diffuser caused by power fluid cavitation and usually indicates little or no PIP.
Solution: Decrease throat size and operating pressure.

JET PUMP POWER FLUID RATE – NOZZLE NO. 3

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	237	262	285	306	326
	1000	262	285	306	326	345
	500	285	306	326	345	363
6000	1500	279	301	321	340	358
	1000	301	321	340	358	375
	500	321	340	358	375	392
8000	1500	316	335	353	371	387
	1000	335	353	371	387	403
	500	353	371	387	403	418
10,000	2000	330	348	366	383	399
	1500	348	366	383	399	414
	1000	366	383	399	414	429
12,000	2000	361	378	395	410	425
	1500	378	395	410	425	440
	1000	395	410	425	440	454
14,000	2000	390	406	421	436	450
	1500	406	421	436	450	464
	1000	421	436	450	464	477

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:
Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 387 BPD @ S.G. 1.0, 387 X 1.06 = 410 BPD @ S.G. 0.8

JET PUMP POWER FLUID RATE – NOZZLE NO. 4

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	300	332	361	388	413
	1000	322	361	388	413	437
	500	361	388	413	437	460
6000	1500	354	381	407	431	454
	1000	381	407	431	454	475
	500	407	431	454	475	496
8000	1500	400	424	448	470	491
	1000	424	448	470	491	511
	500	448	470	491	511	530
10,000	2000	418	442	464	485	506
	1500	442	464	485	506	525
	1000	464	485	506	525	544
12,000	2000	458	480	500	520	539
	1500	480	500	520	539	557
	1000	500	520	539	557	575
14,000	2000	495	515	534	553	571
	1500	515	534	553	571	588
	1000	534	553	571	588	605

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:
Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 491 BPD @ S.G. 1.0, 491 X 1.06 = 520 BPD @ S.G. 0.8

JET PUMP POWER FLUID RATE – NOZZLE NO. 5

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	383	423	461	495	527
	1000	423	461	495	527	557
	500	461	495	527	557	586
6000	1500	451	486	519	549	579
	1000	486	519	549	579	606
	500	519	549	579	606	633
8000	1500	510	541	571	599	626
	1000	541	571	599	626	652
	500	571	599	626	652	676
10,000	2000	533	563	592	619	645
	1500	563	592	619	645	670
	1000	592	619	645	670	694
12,000	2000	584	612	638	663	687
	1500	612	638	663	687	711
	1000	638	663	687	711	734
14,000	2000	631	656	681	705	728
	1500	656	681	705	728	750
	1000	681	705	728	750	772

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:
Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 626 BPD @ S.G. 1.0, 626 X 1.06 = 663 BPD @ S.G. 0.8

JET PUMP POWER FLUID RATE – NOZZLE NO. 6

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	487	538	586	629	670
	1000	538	586	629	670	709
	500	586	629	670	709	745
6000	1500	573	618	660	699	736
	1000	618	660	699	736	771
	500	660	699	736	771	805
8000	1500	649	688	726	762	796
	1000	688	726	762	796	828
	500	726	762	796	828	860
10,000	2000	678	716	752	787	820
	1500	716	752	787	820	852
	1000	752	787	820	852	882
12,000	2000	743	778	811	843	874
	1500	778	811	843	874	904
	1000	811	843	874	904	933
14,000	2000	802	835	866	896	925
	1500	835	866	896	925	954
	1000	866	896	925	954	981

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:
Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 796 BPD @ S.G. 1.0, 796 X 1.06 = 843 BPD @ S.G. 0.8

JET PUMP POWER FLUID RATE – NOZZLE NO. 7

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	620	686	746	802	854
	1000	686	746	802	854	903
	500	746	802	854	903	949
6000	1500	730	787	840	890	937
	1000	787	840	890	937	982
	500	840	890	937	982	1025
8000	1500	826	877	925	970	1013
	1000	877	925	970	1013	1055
	500	925	970	1013	1055	1095
10,000	2000	863	912	958	1002	1044
	1500	912	958	1002	1044	1085
	1000	958	1002	1044	1085	1124
12,000	2000	946	990	1033	1074	1113
	1500	990	1033	1074	1113	1151
	1000	1033	1074	1113	1151	1188
14,000	2000	1022	1063	1103	1141	1178
	1500	1063	1103	1141	1178	1214
	1000	1103	1141	1178	1214	1249

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:

Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 1013 BPD @ S.G. 1.0, 1013 X 1.06 = 1074 BPD @ S.G. 0.8

JET PUMP POWER FLUID RATE – NOZZLE NO. 8

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	789	873	950	1021	1087
	1000	873	950	1021	1087	1150
	500	950	1021	1087	1150	1209
6000	1500	930	1002	1070	1133	1193
	1000	1002	1070	1133	1193	1250
	500	1070	1133	1193	1250	1305
8000	1500	1052	1117	1178	1235	1291
	1000	1117	1178	1235	1291	1344
	500	1178	1235	1291	1344	1395
10,000	2000	1100	1162	1220	1276	1330
	1500	1162	1220	1276	1330	1381
	1000	1220	1276	1330	1381	1431
12,000	2000	1205	1261	1316	1368	1418
	1500	1261	1316	1368	1418	1466
	1000	1316	1368	1418	1466	1513
14,000	2000	1301	1354	1405	1453	1501
	1500	1354	1405	1453	1501	1547
	1000	1405	1453	1501	1547	1591

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:
Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 1291 BPD @ S.G. 1.0, 1291 X 1.06 = 1368 BPD @ S.G. 0.8

JET PUMP POWER FLUID RATE – NOZZLE NO. 9

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	1003	1110	1208	1298	1382
	1000	1110	1208	1298	1382	1461
	500	1208	1298	1382	1461	1547
6000	1500	1182	1274	1360	1440	1517
	1000	1274	1360	1440	1517	1589
	500	1360	1440	1517	1589	1659
8000	1500	1337	1419	1497	1570	1641
	1000	1419	1497	1570	1641	1708
	500	1497	1570	1641	1708	1773
10,000	2000	1398	1476	1551	1622	1690
	1500	1476	1551	1622	1690	1756
	1000	1551	1622	1690	1756	1819
12,000	2000	1531	1603	1672	1738	1802
	1500	1603	1672	1738	1802	1864
	1000	1672	1738	1802	1864	1923
14,000	2000	1654	1721	1785	1847	1908
	1500	1721	1785	1847	1908	1966
	1000	1785	1847	1908	1966	2022

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:
Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 1641 BPD @ S.G. 1.0, 1641 X 1.06 = 1738 BPD @ S.G. 0.8

JET PUMP POWER FLUID RATE – NOZZLE NO. 10

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	1278	1414	1538	1653	1761
	1000	1414	1538	1653	1761	1862
	500	1538	1653	1761	1862	1958
6000	1500	1506	1623	1733	1835	1932
	1000	1623	1733	1835	1932	2025
	500	1733	1835	1932	2025	2113
8000	1500	1704	1808	1907	2000	2090
	1000	1808	1907	2000	2090	2176
	500	1907	2000	2090	2176	2259
10,000	2000	1781	1881	1976	2066	2153
	1500	1881	1976	2066	2153	2237
	1000	1976	2066	2154	2237	
12,000	2000	1951	2043	2130	2215	2296
	1500	2043	2130	2215	2296	2374
	1000	2130	2215	2296	2374	2450
14,000	2000	2107	2192	2274	2354	2430
	1500	2192	2274	2354	2430	2504
	1000	2274	2354	2430	2504	2576

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:
Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 2090 BPD @ S.G. 1.0, 2090 X 1.06 = 2215 BPD @ S.G. 0.8

JET PUMP POWER FLUID RATE – NOZZLE NO. 11

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	1629	1802	1960	2107	2243
	1000	1802	1960	2107	2243	2372
	500	1960	2107	2243	2372	2494
6000	1500	1919	2068	2207	2338	2462
	1000	2068	2207	2338	2462	2580
	500	2207	2338	2462	2480	2693
8000	1500	2171	2304	2430	2549	2663
	1000	2304	2430	2549	2663	2772
	500	2430	2549	2663	2772	2878
10,000	2000	2269	2396	2518	2633	2744
	1500	2396	2518	2633	2744	2850
	1000	2518	2633	2744	2850	2952
12,000	2000	2486	2603	2714	2822	2925
	1500	2603	2714	2822	2925	3025
	1000	2714	2822	2925	3025	3122
14,000	2000	2685	2793	2898	2999	3096
	1500	2793	2898	2999	3096	3191
	1000	2898	2999	3096	3191	3283

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:
Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 2663 BPD @ S.G. 1.0, 2663 X 1.06 = 2822 BPD @ S.G. 0.8

JET PUMP POWER FLUID RATE – NOZZLE NO. 12

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	2087	2309	2511	2698	2873
	1000	2309	2511	2698	2873	3038
	500	2511	2698	2873	3038	3195
6000	1500	2458	2649	2828	2995	3154
	1000	2649	2828	2995	3154	3305
	500	2828	2995	3154	3305	3449
8000	1500	2781	2951	3112	3265	3411
	1000	2951	3112	3265	3411	3551
	500	3112	3265	3411	3551	3686
10,000	2000	2907	3070	3225	3373	3514
	1500	3070	3225	3373	3514	3650
	1000	3225	3373	3514	3650	3782
12,000	2000	3184	3334	3477	3614	3747
	1500	3334	3477	3614	3747	3875
	1000	3477	3614	3747	3875	3999
14,000	2000	3439	3578	3712	3841	3966
	1500	3578	3712	3841	3966	4087
	1000	3712	3841	3966	4087	4205

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:
Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 3411 BPD @ S.G. 1.0, 3411 X 1.06 = 3616 BPD @ S.G. 0.8

JET PUMP POWER FLUID RATE – NOZZLE NO. 13

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	2657	2940	3198	3436	3659
	1000	2940	3198	3436	3659	3869
	500	3198	3436	3659	3869	4069
6000	1500	3131	3374	3601	3814	4016
	1000	3374	3601	3814	4016	4209
	500	3601	3814	4016	4209	4393
8000	1500	3542	3758	3963	4158	4344
	1000	3758	3963	4158	4344	4522
	500	3963	4158	4344	4522	4694
10,000	2000	3701	3909	4107	4295	4475
	1500	3909	4107	4295	4475	4649
	1000	4107	4295	4475	4649	4816
12,000	2000	4055	4245	4428	4603	4772
	1500	4245	4428	4603	4772	4935
	1000	4428	4603	4772	4935	5092
14,000	2000	4380	4557	4727	4891	5051
	1500	4557	4727	4891	5051	5205
	1000	4727	4891	5051	5205	5355

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:
Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 4344 BPD @ S.G. 1.0, 4344 X 1.06 = 4605 BPD @ S.G. 0.8

JET PUMP POWER FLUID RATE – NOZZLE NO. 14

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	3383	3742	4071	4374	4658
	1000	3742	4071	4374	4658	4925
	500	4071	4374	4658	4925	5179
6000	1500	3985	4295	4584	4855	5112
	1000	4295	4584	4855	5112	5357
	500	4584	4855	5112	5357	5591
8000	1500	4508	4784	5045	5293	5529
	1000	4784	5045	5293	5529	5757
	500	5045	5293	5529	5757	5975
10,000	2000	4711	4976	5227	5467	5697
	1500	4976	5227	5467	5697	5917
	1000	5227	5467	5697	5917	6130
12,000	2000	5161	5404	5636	5859	6074
	1500	5404	5636	5859	6074	6281
	1000	5636	5859	6074	6281	6482
14,000	2000	5575	5800	6017	6226	6429
	1500	5800	6017	6226	6429	6625
	1000	6017	6226	6429	6625	6816

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:
Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 5529 BPD @ S.G. 1.0, 5529 X 1.06 = 5861 BPD @ S.G. 0.8

JET PUMP POWER FLUID RATE – NOZZLE NO. 15

PUMP		SURFACE POWER FLUID PRESSURE – PSI				
DEPTH FEET	INTAKE PSI	2000	2500	3000	3500	4000
		POWER FLUID RATE @ S.G. = 1.0 -- BPD				
4000	1500	4306	4764	5182	5568	5930
	1000	4764	5182	5568	5930	6270
	500	5182	5568	5930	6270	6593
6000	1500	5073	5467	5835	6181	6508
	1000	5467	5835	6181	6508	6820
	500	5835	6181	6508	6820	7118
8000	1500	5739	6090	6422	6738	7039
	1000	6909	6422	6738	7039	7328
	500	6422	6738	7038	7328	7607
10,000	2000	5998	6335	6655	6960	7252
	1500	6335	6655	6960	7252	7533
	1000	6655	6960	7252	7533	7804
12,000	2000	6570	6879	7175	7459	7732
	1500	6879	7175	7459	7732	7996
	1000	7175	7459	7732	7996	8252
14,000	2000	7097	7384	7660	7926	8184
	1500	7384	7660	7926	8184	8434
	1000	7660	7926	8184	8434	8677

Factors for other Specific Gravity Power Fluids –

S.G.	Mult. By	°API	S.G.	Mult. By
0.8	1.06	45	1.1	0.97
0.9	1.03	26	1.2	0.94

Example:
Pump 8000 ft., Intake 1000 PSI, Power Fluid 3500 PSI, S.G. 0.8
Power Fluid 7039 BPD @ S.G. 1.0, 7039 X 1.06 = 7461 BPD @ S.G. 0.8