CONVERSION FROM CENTRIFUGAL TO ROTARY POSITIVE DISPLACEMENT PUMPS

by

Morgan M. Bruck

Senior Engineer

Marathon Petroleum

Findlay, Ohio

Barry A. Butler

Product Support Manager

Colfax Corporation

Monroe, North Carolina

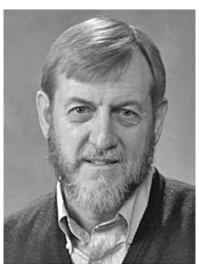
and

Michael L. Moore

Director of Global Oil & Gas Marketing

Colfax Corporation

Brantford, Ontario, Canada



Morgan M. (Morg) Bruck is a Senior Engineer for Marathon Petroleum Company (MPC) in the Engineer Standards and Technical Support Group, located in Findlay, OH. He writes standards related to rotating equipment and measurement and provides tech support in these areas for Marathon Pipe Line and Marathon Terminals, Transport, and Marine. Prior to his position at MPC, Mr. Bruck worked in plant, project, and reliability engineering with The Dayton Power & Light Company and SOHIO Pipe Line Company. He is an active member of API standards committees for pumps and pump repairs and API measurement standards, and he is also a member of the International Pump Users Symposium Advisory Committee.

Mr. Bruck is a graduate of Rose-Hulman Institute of Technology (BSME 1969).

Barry A. Butler is the Product Support Manager for the Colfax Corporation, in Monroe, North Carolina. He has responsibility for its Application Engineering Group and the Technical Services Group. Mr. Butler has obtained areas of increasing responsibility throughout his 30 year career with Colfax that includes three years as a Technical Service Engineer and 10 years as a Product Engineer for the Imo Pump Division. In 1999, he joined the Sales and Marketing Team with a crude oil market focus including application specification, installation, service, and monitoring and product development.

Mr. Butler received his education at North Carolina State University and Central Piedmont CC (AAS Mechanical Engineering).

Michael L. (Mike) Moore is the Director of Global Oil & Gas Marketing for the Colfax Corporation, in Brantford, Ontario, Canada. The first 16 years of his career were spent with the Flowserve Pump Division working with a wide variety of centrifugal and positive displacement pump types. His work experience with Flowserve spanned the engineering, field service, project management, and new product development departments. The last five years of Mr. Moore's career have been spent working with Colfax, initially as their Senior Multiphase Engineer and then as Colfax Americas' Crude Oil Product Marketing Specialist prior to taking on his current responsibilities. For the last five years, he has served as the task force secretary for API 676 - Positive displacement pumps - rotary, and he is a member of the International Pump Users Symposium Advisory Committee.

Mr. Moore received his education (Mechanical Engineering) at McMaster University and the Mohawk Technical Institute.

ABSTRACT

A major U.S. pipeline company was experiencing multiple problems at a crude pipeline intermediate pump station:

- Pipeline pumps were rated for 3500 to 7000 bph on 20 cSt crude (original design).
- Reliability and mean time between repair (MTBR) problems on existing centrifugal pumps because of operating at about 600 bph
- Viscosities ranging from 1500 cSt to 5000 cSt (versus original design)

- The installed pumps also were under a power company restriction of 500 hp maximum (because of inrush current limit at starting conditions).
- The required flow rates varied from about 425 bph to 800 bph.
- Because of viscosity correction the centrifugal pump efficiency varied from about 10 to 20 percent when MTBR allowed the pumps installed to run.
- Pressure management on the pipeline system was not evenly distributed between the stations.

The application seemed ideal for a rotary positive displacement (PD) pump. However, there was an additional complication/concern because only a few company personnel had experience with operating positive displacement pumps in series on a "tight-line" operation.

The pipeline company's personnel worked with vendors to select a probable pump. The selected vendor provided several pipeline companies as reference examples of running rotary PD pumps in series across a pipeline system. After observing firsthand the operation of a pipeline system in Canada, the company then used computer simulations to model the hydraulic responses of the pump, controls and pipeline system. The computer simulations convinced management that rotary PD pumps would indeed function properly and safely in series with reciprocating PD pumps that were located at the originating pipeline station (upstream in the system).

Additional items that were addressed as part of the redesign of the station were:

- Equipment vibration level reduction.
- Flow-rate flexibility and control system upgrades for the system and redesigned station.
- Electrical distribution stability for the station.

Once installed, the rotary PD pumps provided improved MTBR, better pressure management, and more cost effective operation of the pipeline system in question. The throughput increase averaged 39 percent even though the increased power cost was only 9 percent.

The tutorial will show examples of:

- Operating data showing system flow before and after station redesign.
- Rotating equipment installation improvements using before and after photos.
- Operating data showing pressure management improvements.
- Station operating costs before and after and cost per barrel improvements.
- Pump testing and inspection to ensure minimal startup issues.

INTRODUCTION

Within the U.S., and probably worldwide, piping systems, pipelines and the pump trains that provide the flow within these systems have seen fluids with ever increasing specific gravity and viscosity.

Pipelines systems intended to meet the increasing demands of World War II and the increasing demands of North American consumers in the postwar era, often were designed for flow of 5000 bph to 20,000 bph ± on crude oil of 20 cSt to 50 cSt. However, these pipeline systems found operating flows declining by the last decade of the 20th Century and in many cases conditions in the early 2000s found flow at 10 percent to 20 percent or original and viscosity 100 to 200 times higher.

This tutorial encompasses:

- A decline from a design of ~7000 bph to ~700 bph.
- An increase of density from ~0.85 to ~0.93.
- An increase of viscosity from 20 cSt to 3000 cSt.
- How is this fluid cost-effectively pumped at the desired flow?
- How is MTBR optimized?
- How can all the above be done and operate safely (i.e., operate within 49CFR195)?

Refer to Figures 1 through 4.

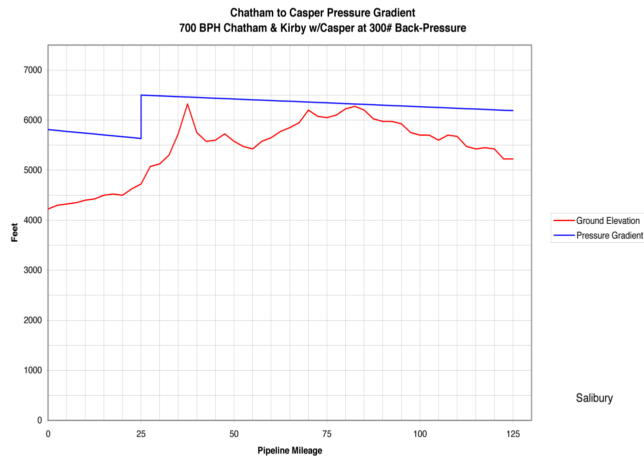


Figure 1. 20cSt with Centrifugal Pump.

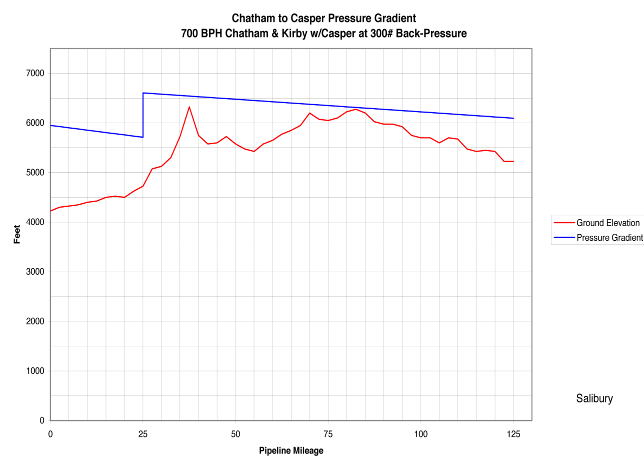


Figure 2. 3000 cSt with Centrifugal Pump.

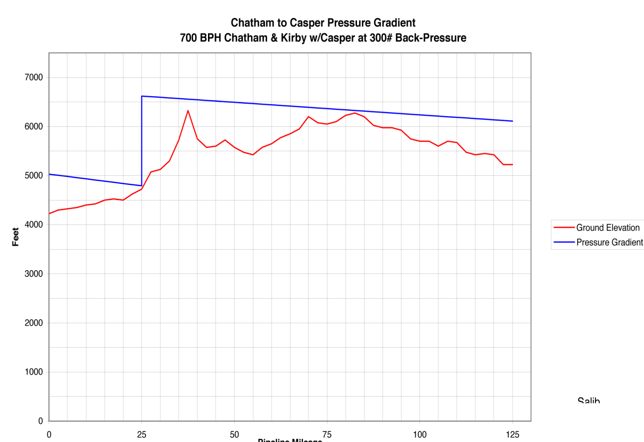


Figure 3. 3000 cSt with Three-Screw.

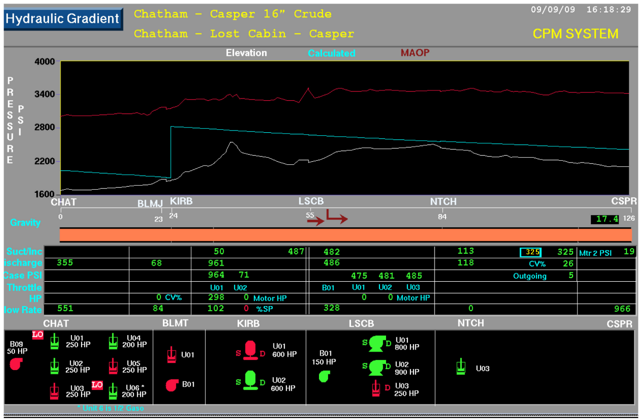


Figure 4.

OVERVIEW

The pipeline, which is the example for this tutorial, has three pump stations, all originally centrifugal pumps. The pump station, which is the example that led to this tutorial, was designed for flow rate of 3500 bph to 7000 bph for crude oil that was about 20 to 30 cSt at ambient temperature. By 1985 the station was operating at approximately 1000 bph. In 1998 the flow rate had further declined to 700 bph. Viscosity and density had increased such that station discharge pressures were nearly identical to initial 1950 design at the lower flow rates.

Kirby pump station had two pumps. Pump #2 was 4×6×10 pump with four stages and a best efficiency point (BEP) of about 1570 bph and Pump #1 that was a 6×10×19 two-stage double suction first stage with a BEP of about 3500 bph. Pump #1 had issues of maximum allowable operating pressure (MAOP) for the desired flow rate and Pump #2 had a horsepower issue for the desired flow rate.

As time passed from 1950, the input station upstream of Kirby Station was converted to only reciprocating, positive displacement pumps. The pumps at the Kirby Station and the Lost Cabin Station (next station downstream) remained centrifugal pumps. As flow rate declined and density and viscosity increased, the efficiency of the centrifugal pumps dropped. Operating costs increased but not sufficiently to financially justify the replacement of the centrifugal pumps with rotary PD pumps purely from operational savings. Many pipeline company personnel had considerable reservations about the real feasibility of running PD pumps in series while operating a pipeline in a "tight-line" manner.

So let us digress to a time before your presenters today were born, even before I was born! In the 1940s and early 1950s, crude pipelines often operated with PD reciprocating pumps. Operators for pipelines with all PD pump stations would get on a phone line called a "ring down circuit" (a.k.a. "party line") and would start up the pipeline system by watching station incoming pressure and bringing the variable speed, diesel driven, pumps up to speed when pressure increased to about two times required pump suction. This operating method prevailed until the 1970s in many locations. (Fortunately, I was a novice engineer at the extreme back end of this operational method). Suffice it to say, participating in the operation of a "series PD pipeline" prejudiced my thoughts of how to handle high viscosity crude. Faced with:

- Pipeline pumps were rated for 3500 to 7000 bph on 20 cSt crude (original design).
- Reliability and mean time between repair problems on existing centrifugal pumps because they operate at about 700 bph.
- Viscosities ranging from 1500 cSt to 3000 cSt (versus original design).
- The installed pumps also were under a power company restriction of 500 HP maximum (because of inrush current limit at starting conditions).
- The required flow rates varied from about 425 bph to 800 bph, 700 bph average (varied by month and crude oil price).
- Because of a viscosity correction, the centrifugal pump efficiency varied from about 10 to 20 percent when MTBR allowed the installed pumps to run.
- Pressure management on the pipeline system was not evenly distributed between the stations.
- Lastly, Kirby Station was located near a creek bed that brought soil stability issues into consideration and meant that station design would require:

  - Thorough core samples and soils analysis.
  - Cojoined pump foundations for vibration reduction and equipment stability.

The pipeline company's and engineering, procurement, construction (EPC) engineers involved tried finding ways to make the existing centrifugal pumps work, but efficiency and MTBR were unacceptable. The engineers requested several major U.S. manufacturers of centrifugal pumps to "look again" at possible selections, but it just was not possible to put a square peg in a round hole. The viscosity was so high and the flow range was so low that performance predictions approximated educated guesses. Performance testing on water would not provide realistic indication of performance at rated viscosity and therefore performance guarantees and three-year API run times were thought impossible.

Finally, with no real options left, some more experienced engineers convinced a few others and one brave systems programmer to try to model the proposed operation with rotary PD pumps in series. The model showed that the system was stable when adjustable speed drives (ASDs) (a.k.a. variable frequency drives [VFDs]), flow recirculation, and pressure relief valves at downstream stations were properly applied. One supplier replied to a request for users who possibly had systems similar to the one that was modeled and we began the task of redesigning the pipeline station and operation.

DESIGN PROCESS

It was understood that the following could not be changed:

- MAOP could not change from 1150 psi (825 to 875 discharge at average flow)
- Flow rate range had to remain 400 bph to 800 bph (typical 700 bph)
- Viscosity range was 1500 to 3000 cSt
- The local power supplier would not allow more than 400 hp motors with across the line starting because of inrush current possibly causing "flicker" or voltage dip during pump/motor start-up.

It was necessary to determine if the pipeline controls could react properly with the proposed rotary PD pumps. Therefore a hydraulic simulator was programmed with two rotary PD pumps that were controlled by ASDs and that controlled the following:

- Station discharge pressure
- Pump suction pressure
- Pump horsepower
- Pipeline flow rate

It was assumed that normally the controller would control on the pump suction parameter. However, there was concern that an upset requiring a rapid control shift from pump suction to some other parameter—probably station discharge pressure but possibly horsepower—could occur. The primary concern with these parameters was that one would "fight" another and the pump control system at the station would go out of control and overpressure the station piping or downstream pipeline.

There was also concern that if an immediate stop was issued to the pump controls the bypass and relief piping could not respond rapidly enough to prevent overpressure of station piping. Figures 5, 6, and 7 show, respectively, piping and instrumentation drawings of the controls for one pump, the API 676 recommended control for a single pump, and the control for the entire station. Because the station is pigged 25-30 times a year, several tests and surge analyses were modeled and tested for automatic pig detection and shut down.

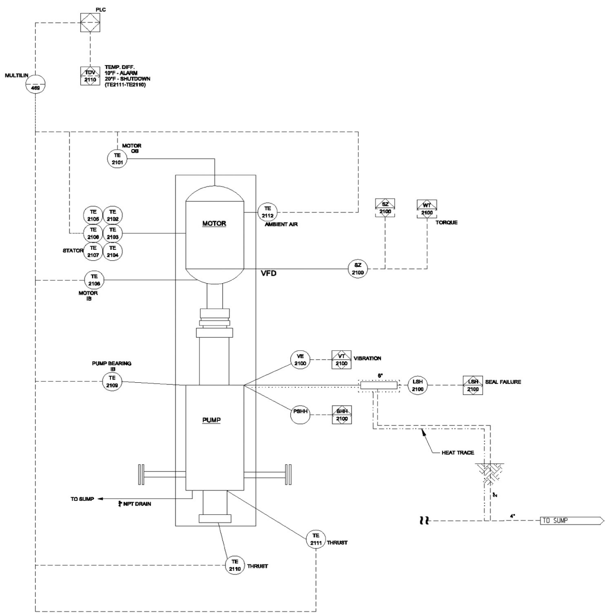


Figure 5. Kirby Rotary PD Pump Units PID.

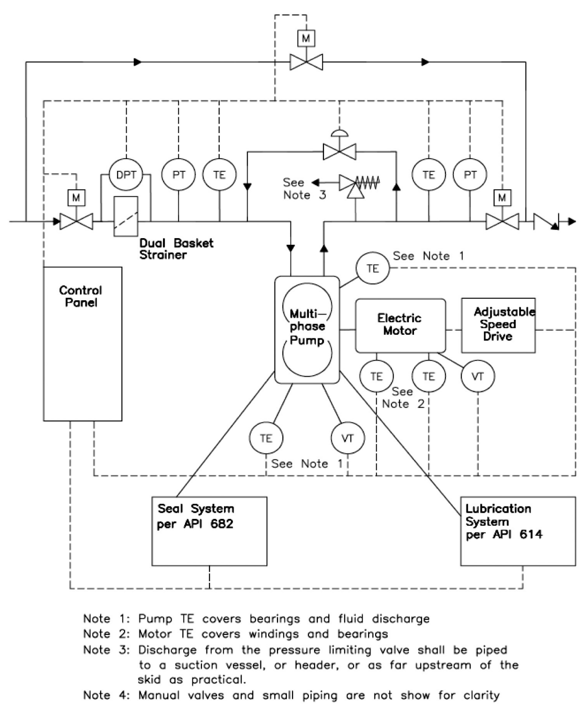


Figure 6. Typical P&ID for Multiphase Pump Skids.

As the process of building a computer model began, fact finding trips were planned to several companies already using similar pumps and control parameters. The plan was to observe as many normal pumping unit start/stop sequences as possible without requesting the host companies to perform immediate stop operation of the pumps.

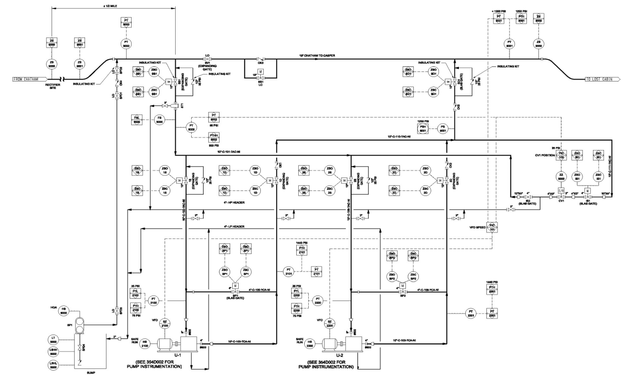


Figure 7. PID for the Station.

Predicted design data was taken for the rotary PD pumps and that data was input into the model that had most of the PID information noted in the previous figures and those data were plugged into the pump data (Figure 8).

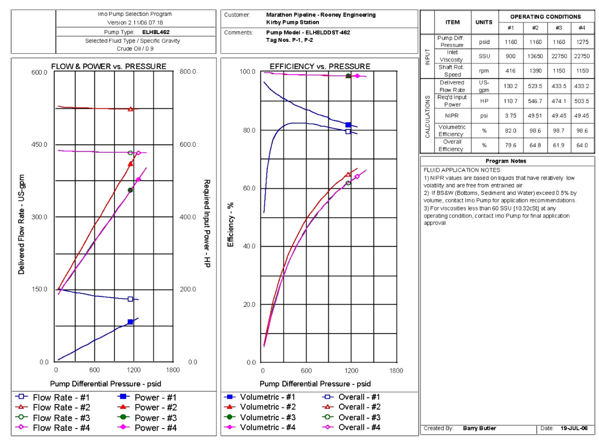


Figure 8.

The spreadsheet (Figure 9) shows the impact of fluid viscosity on the pump input horsepower required. The input energy required by the centrifugal pumps increased significantly with viscosity. The horsepower required by the rotary PD pumps was much more stable, for some viscosities even decreasing.

Required operating condition - 700 BPH (490 gpm) working within 400 BHP limit

	4x6x10 - 4 stage		8L462 rotary screw	
	One pump @ 3550 rpm		Two ASD pumps in parallel	
Viscosity Case	Eff'y. (%)	BHP	Eff'y. (%)	Total BHP
20 cSt - 1585 feet TDH	60.2	276	76.1	258
200 cSt - 1544 feet TDH	46.5	371	84.6	226
500 cSt - 1476 feet TDH	37.4	439	82.0	223
1500 cSt - 1302 feet TDH	22.7	660	72.4	223
3000 cSt - 982 feet TDH	9.3	1213	58.1	210

	6x10x19 - 2 stage		8L462 rotary screw	
	One pump @ 1750 rpm		Two ASD pumps in parallel	
Viscosity Case	Eff'y. (%)	BHP	Eff'y. (%)	Total BHP
20 cSt - 744 feet TDH	29.5	265	79.2	117
200 cSt - 744 feet TDH	25.5	325	80.1	115
500 cSt - 738 feet TDH	18.8	452	73.6	124
1500 cSt - 719 feet TDH	15.0	552	60.6	147
3000 cSt - 688 feet TDH	11.0	720	49.7	172

Required flow rate at desired discharge pressure of 875 psig

	Centrifugal solution		8L462 rotary screw	
	One pump		Two ASD pumps in parallel	
Viscosity Case	Eff'y. (%)	BHP	Eff'y. (%)	Total BHP
20 cSt - 2378 feet TDH	N/A	N/A	74.5	336
200 cSt - 2246 feet TDH	N/A	N/A	85.1	294
500 cSt - 2173 feet TDH	N/A	N/A	84.3	297
1500 cSt - 2173 feet TDH	N/A	N/A	78.9	317
3000 cSt - 2173 feet TDH	N/A	N/A	72.9	344

Figure 9.

FOUNDATIONS AND BASEPLATES

The best hydraulic design can still produce an installation that operates at less than optimal MTBR if the soil conditions, foundation, and baseplate are not well designed. Figures 10 through 14 show how the site was prepared and the foundation and baseplate were designed to optimize MTBR as well as how the baseplates were located on the foundation.

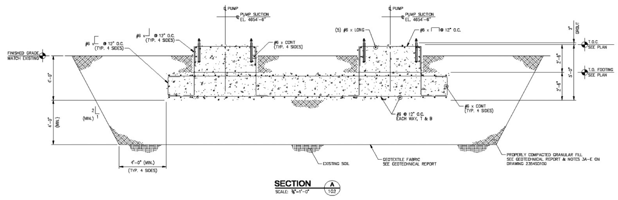


Figure 10.

Figure 11.

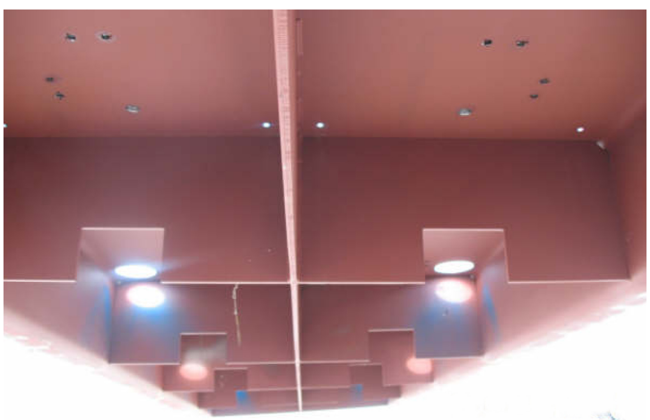


Figure 12.

Figure 13.

Figure 14.

The baseplates were shipped with no equipment mounted. The foundation surfaces where epoxy grout was to be installed were scarfed. The baseplates were then lowered into position on the foundations, leveled, and grout was poured and cured for 48 hours. The equipment was then placed and aligned.

Photos of the finished station, showing layout and protective monitoring equipment are shown in Figures 15 through 23.

Figure 15.

Figure 16.

Figure 17.

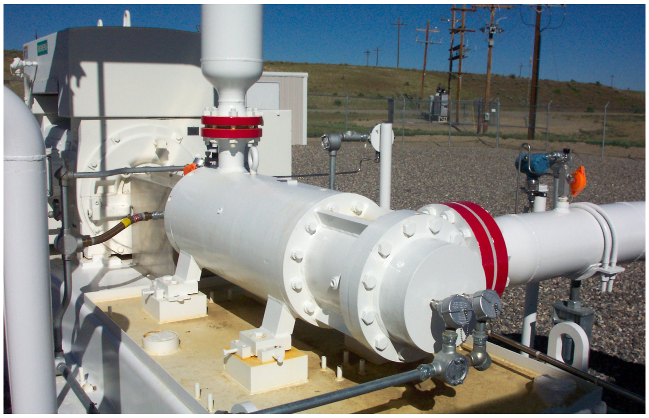


Figure 18.

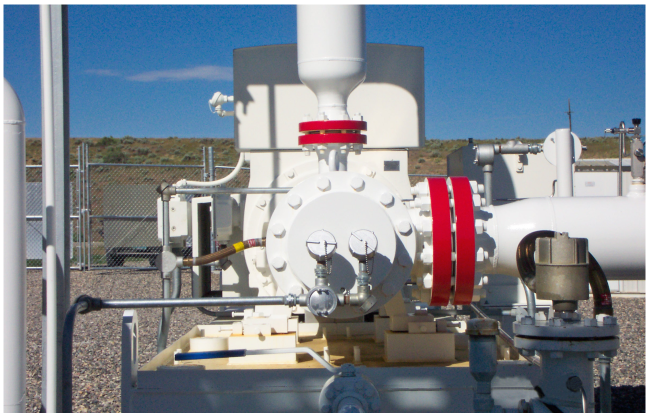


Figure 19.

Figure 20.

Figure 21.

Figure 22.

Figure 23.

The pipeline company chose to purchase a major repair kit as shown in the Unit cross section drawing in Figure 24 and material list in Figure 25. To date there have been no repairs required for the two pumps installed and operational in October 2007.

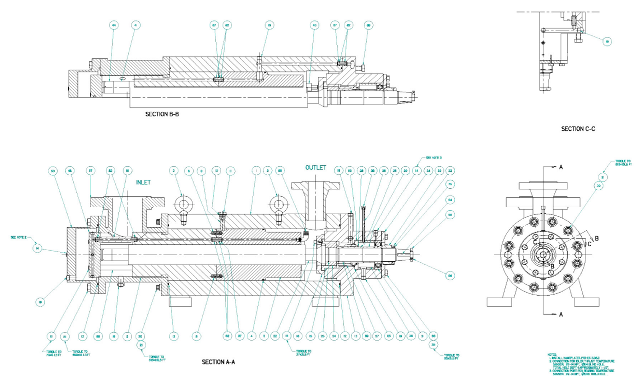


Figure 24. Unit Cross Section Drawing.

J8LDDSX-462		Major Repair Kit
IDP	Quantity	Description
3	1	ROTOR HOUSING
4	1	O-RING
5	1	ROTOR HOUSING
8	2	PIN, DOWEL, PULL 3/4 X 2"
9	1	ROTOR HOUSING STOP PIN
10	1	O-RING
12	3	O-RING
15	1	BALANCE PISTON BUSHING
16	1	IDLER STOP SUB-ASSY. INCL.
22	1	ROTOR POWER
23	1	O-RING
24	1	BALANCE PISTON PISTON
27	1	MECHANICAL SEAL
28	1	RING SPIR. #US-375
31	1	BEARING
40	2	IDLER ROTOR
41	2	IDLER ROTOR
44	2	IDLER BALANCE PISTON HOUSING
48	1	THRUST PLATE SUB-ASSY
65	1	GASKET
69	1	O-RING
81	1	OIL BALANCE TUBE
82	8	O-RING
87	3	OIL BALANCE TUBE
90	1	STRAINER SUB-ASSEMBLY

Figure 25. Material List.

MAINTENANCE AND UNIT AVAILABILITY

The units described in this tutorial have been operational for three years. Seals and bearings are still those installed at the original equipment manufacturer's (OEM's) plant. The units do have periods of unavailability but 95 percent of the time not available is attributable to electrical issues such as surges that trip the AFDs or cause motor operated valves to stop in transit. The station also shuts down automatically each time a pipeline cleaning tool passes.

CONCLUSION

Table 1 shows the operating statistics for the subject pumps and system. As can be seen, the system is operating ~39 percent higher throughput with ~9 percent additional power cost. This a net of ~30 percent flow increase for the same power cost. The main reason that the power cost is not lower is due to electric company demand charges. The new pumps are so reliable that they run nearly continuously. Maintenance costs have declined to approximately one-fourth of the centrifugal pumps. When crack spread, maintenance cost, and power costs are summed, it is estimated that the installation paid for itself in about two years.

Table 1. Power Cost and Shipping Cost/Barrel.

Chatham pump to Casper										
Bbls./day	2006	2007	2008	2009		2006 $/Bbl	2007 $/Bbl	2008 $/Bbl	2009 $/Bbl	
JAN	10,794	10,446	13,852	12,839		1.00	1.01	0.91	0.96	
FEB	5,112	13,640	13,443	12,580		1.86	0.79	0.90	0.97	
MAR	7,566	13,153	10,213	6,747		1.47	0.83	1.03	1.28	
APR	6,651	13,247	14,643	7,849		1.23	1.35	1.04		
MAY	15,305	10,272	11,903			0.59	0.84	0.92		
JUN	14,719	14,652	10,049			0.42	0.54	0.94		
JUL	11,827	17,507	11,531			0.51	0.51	0.88		
AUG	12,699	17,397	11,372			0.40	0.50	0.86		
SEP	14,835	8,352	8,824			0.38	0.67	0.96		
OCT	11,100	9,197	7,427			0.47	0.57	1.21		
NOV	10,416	12,107	8,368			0.98	0.80	1.17		
DEC	11,168	9,758	13,553			1.08	0.99	1.07		
					Average	0.87	0.78	0.99	1.07	
Total	132,191	149,727	135,178	40,015						
Average	11,016	12,477	11,265	10,004						
Winter	51,705	72,351	74,073	40,015						Average
Increase		1.40	1.43	1.33	1.39		0.90	1.14	1.23	1.09
Black Mtn.										
JAN	1,487	1,363	1,333	1,243						
FEB	1,504	1,207	1,401	1,303						
MAR	1,480	1,396	1,361	1,237						
APR	1,342	1,212	1,336	1,258						
MAY	1,385	1,365	1,336							
JUN	1,355	1,287	1,396							
JUL	1,276	1,264	1,313							
AUG	1,488	1,332	1,401							
SEP	1,380	1,284	1,308							
OCT	1,352	1,419	1,332							
NOV	1,344	1,285	1,343							
DEC	1,355	1,372	1,301							
Total	16,748	15,785	16,161	5,041						
Average	1,396	1,315	1,347	1,260						
Chat+Kirby										
JAN	12,281	11,809	15,185	14,081						
FEB	6,616	14,847	14,844	13,883						
MAR	9,046	14,549	11,574	7,984						
APR	7,993	14,459	15,979	9,108						
MAY	16,690	11,636	13,239	-						
JUN	16,074	15,938	11,445	-						
JUL	13,103	18,771	12,844	-						
AUG	14,187	18,729	12,773	-						
SEP	16,215	9,636	10,132	-						
OCT	12,452	10,616	8,760	-						
NOV	11,760	13,392	9,711	-						
DEC	12,522	11,130	14,855	-						
Total	148,939	165,513	151,339	45,056						
Average	12,412	13,793	12,612	3,755						