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Online Energy Management Pumping Station Optimization

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Abstract

Operators of liquid pipeline networks with multiple pumping stations are looking for ways to optimize operations, reduce fuel consumption and costs, and maximize producer and consumer throughput in real time. This paper introduces a different method for optimal pipeline operation and achieves the stated objectives by integrating a real-time based optimization algorithm into a configured, dynamic model to predict how the pipeline stations and units will respond to changes in each of the independent variables along the pipeline. The real-time optimization focuses on the different costs of operation as they change throughout the day and drag reducing agents cost and give suggested set points of pump operation as well as drag reducing agent set points. Through this method a prediction of future moves and a process operating forecast can be built to maintain optimal operations in accordance with a defined target. Drag reducing agent and batch algorithms and the simulator results were validated with real field data from a liquid pipeline to ensure model and simulation accuracy. Technological advances incorporated into the pipeline simulator included advanced regulatory control, drag reduction, batching and incorporating algorithms for daily timed operations (differences in electrical costs throughout the day). This paper describes our method and these advances and demonstrates how they may be applied to liquid pipelines to see current operating modes versus suggested operating modes.

Introduction and Background

Liquid pipelines transport large quantities of fluid across long distances and deliver it to major consumers (local distributors, large industrial end users, electrical generation facilities). Two groups of liquid petroleum pipelines exist: crude oil lines and refined product lines. Crude oil lines normally run from production gathering areas to refineries. Refined product lines consisting of gasoline, jet fuel, home heating oil, and diesel are often transported from refineries to local distrubtors. The liquid pipeline network is composed of several pieces of equipment that operate together to move products from location to location. The main elements of a pipeline system are the supply or inlet station which is the beginning of the pipeline where the product is injected into the line. Storage facilities and pumps are usually located at these locations. Pump stations which are pumps driven by electrical motors or gas engines are located along the line to move the product through the pipeline. The location of these stations is defined by the topography, the type of product being transported, or operational conditions of the network. Partial delivery stations or intermediate stations exist that allow the pipeline operator to deliver off the pipeline. Block valve stations are the first line of protection for pipelines where the operator can use these block valves to isolate any segement of the line for maintenance work or isolate a rupture or leak depending on the pipeline. The final delivery point or outlet station or terminal is where the product will be distributed to the consumer. A tank terminal or refinery are normally the end points for liquid pipelines.

With the complex operational envelope of a liquid pipeline it is difficult to solve how to optimize the pipeline. The paper looks at an algorithm to generate suggested pump station and drag reducing agent set points using traditional optimization techniques. The goal of the algorithm is to minimize the cost per barrel of the pipeline and the methodology presented in this paper is unique in that it was designed to model diverse unit configurations and generate optimization results based on a user defined objective function.

TRANSIENT FLOW SEGMENTS

Transient pipe flow simulation is based on the concept that flow changes are a result of pressure waves created by disturbances. A pressure wave travels close to sonic velocity, C. During the computation scan time, Δt, the pressure wave propagates a distance L in the pipe. L is calculated using equation 1 as an approximation.

$$L = C \cdot \Delta t \quad (1)$$

Initially, the pipeline is divided into sufficiently small sections, or segments of length L, as illustrated in Figure 1. Segments represent each type of modeled component. For example, pumps, pipeline nodes, and control valves are all modeled as a segment. Each component is described by equations of motion, continuity, energy, and specific state. Pressure, temperature, density, and mass flow are assumed to be the same from the left end of the segment to the right end.

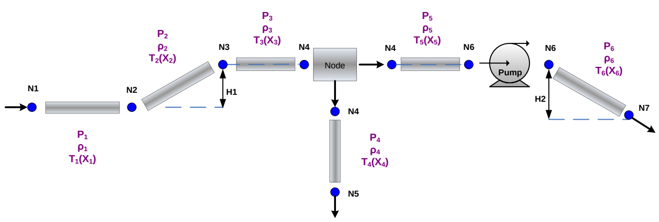

Figure 1 – Dividing a pipeline into segments

BUILDING THE MATHEMATICAL MODEL

The fluid flow mathematical model determines fluid behavior throughout the pipeline by solving a system of nonlinear partial differential equations for four state variables:

- Pressure (P)
- Temperature (T)
- Density (ρ)
- Mass Flow (M)

These equations incorporate the following:

- Derivatives from equations of motion, continuity, energy, and state
- Inertia
- Pseudo component mixture composition expressed in molecular fractions
- Equation of state for fluid flow related to pressure, temperature, and density
- Fluid properties that change with changing conditions
- Heat exchange with outside environment
- Ambient temperature
- Pipe cross-sectional area, pipe fittings, and pipe resistance configurable for each pipeline segment
- Friction factor as a function of the Reynolds number

Equation 2 expresses the continuity equation, which states that the mass of the control volume remains constant:

$$-\frac{\partial M}{\partial x} = A\frac{\partial \rho}{\partial t} \quad (2)$$

where A is the cross-section area. The Navier-Stokes equation that applies Newton's second law of motion to viscous fluids is the material derivative and given in equation 3.

$$\rho\frac{Dw}{Dt} = \rho g - \frac{\partial P}{\partial x} + \mu\frac{\partial^2 w}{\partial x^2} \quad (3)$$

where g is the acceleration due to gravity, μ is the viscosity, and w is the flow velocity. The equation of state given in equation 4 relates pressure, temperature, and density.

$$M = f(P, T, \rho) \quad (4)$$

The equation of energy (equation 5) states that if heat is added to the system or the system does work, the system energy changes according to the First Law of Thermodynamics.

$$q = D\frac{\partial}{\partial t}\left(c_v T + \frac{w^2}{2}\right) + \frac{P}{\rho A}\cdot\frac{\partial(Aw)}{\partial x} + \frac{w}{P}\cdot\frac{\partial P}{\partial x} \quad (5)$$

where D is the diameter and c_v is the specific heat at constant volume.

PUMP AND DRA MODEL

A pump increases pressure by transferring mechanical energy from the motor/engine to the fluid through the rotation of the impeller. Fluid flows from the inlet to the impeller center and out along its baldes. The centrifugal force increases the fluid velocity and the kinetic energy is transformed to pressure. The pump model is based on an empirical set of performance curves. The performance curves are available from the manufacturer and provide the collection of characteristic lines over a certain range of rotational speeds. For a given speed, a characteristic line describes the flow versus head relationship. In addition to head, the power consumption and efficiency can be found in the manufacturer data sheet. Flow, head, and power consumption vary with speed.

Net Positive Suction Head (NPSH) describes conditions related to cavitations. Cavitations are the formation of vapor bubbles in areas where the pressure locally drops to the fluid vapor pressure; they occur at the point in the pump where the pressure is lowest. NPSH is a flow versus head characteristic line that describes the lowest value required for acceptable operating conditions as illustrated in the pump map below.

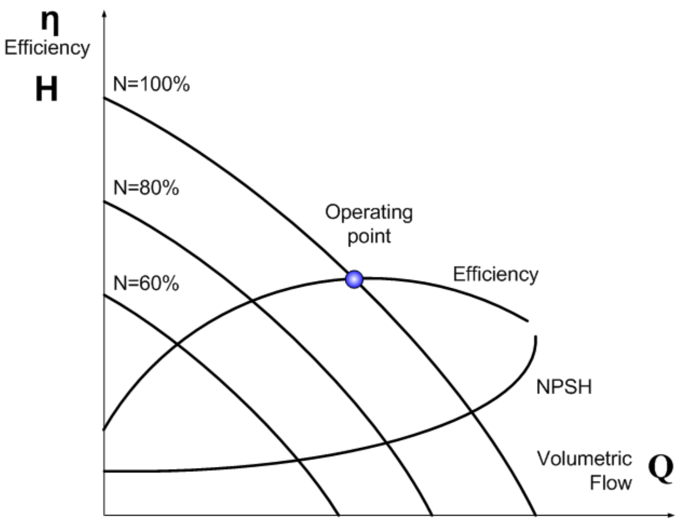

Figure 2 – NPSH diagram

The y-axis is represented using two numbers, Head (H) and efficiency (η). The x-axis is the volumentric flow. The N lines are the speed or frequency of the pump where the pump is loaded at maximum speed or frequency (N=100%), the pump is loaded at 80% maximum load (N=80%), and the pump is loaded at 60% load (N=60%). The core dynamic simulation is a mathematical model that simulates the pump transient behavior based on heat and material balance and the performance curves. The simulation predicts the intermediate process conditions when the flow is transitioning from a pipe to a pump and then into a pipe. In a dynamic simulation, the flow of the pump is based on the head/volumetric flow relationship and the efficiency or volumetric flow relationship. Since the head cannot be directly measured it must be calculated as a function of fluid properties and several measureable process variables as expressed in equation 6.

$$H = \frac{dPtot}{\rho \cdot \mathrm{g}} \qquad (6)$$

Where H is the pump head representing the change in fluid energy. dPtot is the total differential pressure across the pump, ρ is the fluid density, and g is the gravitational acceleration. The total pressure difference across the pump is calculated using the equation 7.

$$dPtot = \mathrm{dPstat} + \mathrm{dPdyn} \quad (7)$$

dPstat is the static pressure difference across the pump and dPdyn is the dynamic pressure difference across the pump. The static pressure difference is computed with flow simulation equations and the dynamic pressure is a function of the fluid velocity and is calculated using equation 8.

$$dPdyn = 0.5 \cdot \rho \cdot V^2 \quad (8)$$

Power curves, such as the one shown in the figure below show the energy transfer rate as a function of flow. Power consumption is dependent on fluid density as well. Hydraulic power (MW) is the power transferred from the pump to the fluid.

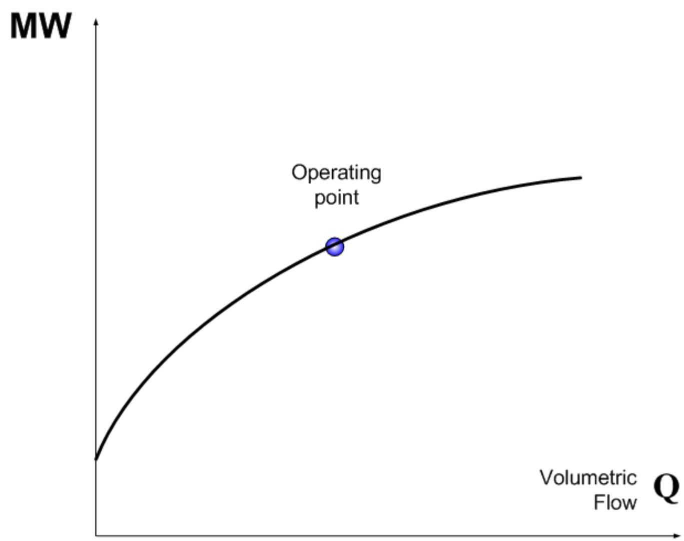

Figure 3 – Power Curve

As seen in the equation below the hydraulic power is calculated based on flow, head, and density.

$$MW = \mathrm{H} \cdot \mathrm{g} \cdot \rho \cdot \mathrm{Q} = \mathrm{dPtot} \cdot \mathrm{Q} \qquad (9)$$

Total efficiency is the ratio between the hydraulic power and shaft power (MWs) and is calculated in the equation below.

$$\eta = \frac{MW}{MWs} \quad (10)$$

Now the pump model has been created it is time to investigate the effects of DRA on the flow and pressure of the pipeline.

Drag reducing agents are chemicals that are added to a pipeline to reduce the friction of the fluid that is transported through the pipes. Typically, DRAs are long polymers that reduce the frictional pressure loss across a pipe by lowering the amount of turbulent motion that occurs within the pipe. Several factors influence the impact a DRA will have on frictional pressure loss. At a given point along the pipeline those factors include:

- The amount of DRA that is present at that point of the pipeline.
- The amount of fluid that is present at that point of the pipeline.
- Chemical properties of the DRA
- The chemical properties of the petroleum that is being transported.
- The operating conditions (pressure, temperature, and mass flow rate) at that point of the pipeline.

The impact that those factors have on the frictional pressure loss can be specified through characteristic curves below.

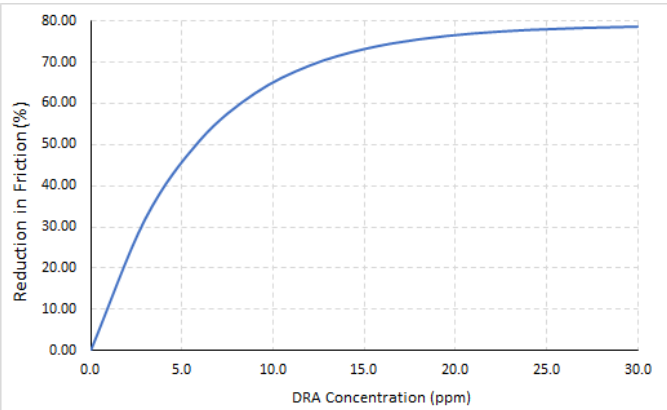

Figure 4 – Reduction in Friction vs DRA concentration

As the figure above shows as the DRA concentration increases the friction is reduced. The curve can also come in a reduction in friction vs. pressure as shown in Figure 5.

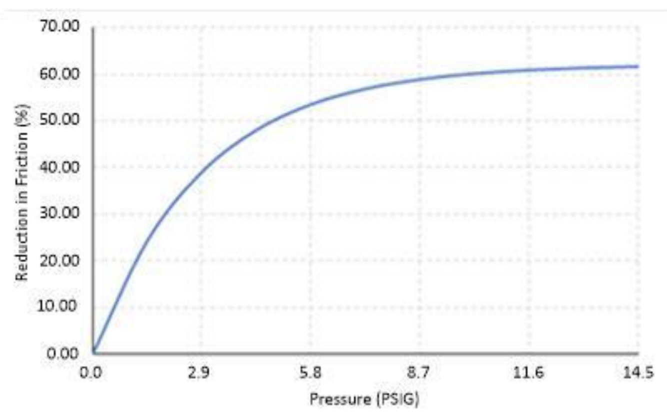

Figure 5 – Reduction in Friction vs Pressure

Now that the pump and DRA model have been created an optimization algorithm needs to be implemented.

PUMPING STATION OPTIMIZATION

Optimization uses the configured, dynamic model to predict how the pipeline, stations, and units will respond to changes in each of the independent variables. The purpose of the model is to predict future moves and build a process operating forecast to maintain the operation in accordance with a defined target. The optimization is solved by finding the optimal set of manipulated variable values to globally optimize the objective function subject to the operator-provided constraints by comparing the real-time objective function value with the optimization-calculated value after the suggested changes. The objective function's original domain is split into subdomains according to various constraints. Partial derivatives are computed in each subdomain and the objective function values are recorded at points in the associated subdomain. The objective function optimal values are recorded along with the values of the manipulated variables present in the computation. The set points are determined and then sent to the operator. The set points are found based on the constrained optimization by linear approximation (COBYLA) which is used to find the global optimal point of the objective function.

The optimization looked at several manipulated variables and constraints. The main constraint is taking all units that are running as running and all units that are turned off as off where the system is looking at the manipulated variables of the station and pumps that are active or on and not looking at turning on or off any pumps. The optimizations purpose is to optimize the distribution of load across all units, stations, and along the entire pipeline while still requiring the provided throughput of the pipeline. Once the optimial output has been established the system is able to find the most optimal pumps to start up or turn off based on system constraints and available units to start up and turn off. Now the optimization has the current scenario and the manipulated variables need to be defined to output the manipulated variables to the operator.

The manipulated variables are independent variables that can be manipulated by the operator to achieve the algorithm target and objective. In this project five different manipulated cases existed.

- Case 1 – an electric driven pump with no variable frequency drive control. The user can turn on or turn off the pump. The main constraint in Case 1 is how quickly an operator can turn on or turn off a pump. If the algorithm suggests turning on a pump every 15 minutes and the operator can only turn on or off a pump once every two hours, the on/off suggestion is not helpful, so the algorithm needs to know the constraint of reaction time to the operators.
- Case 2 – an electric motor-driven pump with variable frequency control. The user can change the pressure set point to change the speed of the pump.
- Case 3 – a gas/diesel engine motor-driven pump with

no speed control available. The user can turn on or turn off the pump.

- Case 4 – a pumping station with a throttle valve downstream pressure control. The user can change the pressure set point to change the speed of the pump.
- Case 5 – The pumping station has a drag reducing agent after the pumps on the station. The user can adjust the amount of DRA injected to the pipeline after the substation.

The cases presented above can be found in each pumping station and some stations can have more than 1 case. For example a pumping station can have an electric motor-driven pump with variable frequency control (Case 2) and it can have a drag reducing agent after the pump (Case 5), so the list isn't exhaustive of what the pumping station can have in it for manipulated variables. With the manipulated variables laid out the algorithm needs to know the constraints of the pipeline.

The optimal scenario can only be found with the required operating constraints. The constraints below in the table show which cases they apply to.

Table 1 – Constraints on Manipulated Variable Cases

	Cases				
Constraints	**1**	**2**	**3**	**4**	**5**
Minimum time between start/stop command	x	x			
Max motor power limit	x	x			
Minimum time between start/stop command and idle/run			x		
Max Engine Power Limit			x		
Min and Max Speed limits		x			
Valve Position Min and Max				x	
DRA Flow Max Limit					x
Station Suction and Discharge Pressure Limit	x	x	x	x	x
Unit Availability	x	x	x	x	x
Pipeline Segment Minimum and Maximum Velocity Limits	x	x	x	x	x

The objective function has been defined, the manipulated variables are selected, and all our constraints are in place it is time to test the algorithm in the field.

CASE STUDY

The optimization algorithm presented in this paper was implemented on a 290-mile crude oil pipeline that ranges from 12 inches to 16 inches along the pipeline. The pipeline has numerous pumping stations with at least one pump at each station. The pipeline has 8 pumping stations with either electric motor driven pumps or gas/diesel engines or turbines to drive the pumps. Drag reducing agents are at several stations as well. Table 2 shows the amount of stations, the number of pumps at each station, the type of pump, and whether the station has DRA.

The table below describes the pumping station number, the number of units per station, the availability of controlling the flow through a control valve on the discharge of the pumping station, whether the pumps in the station were driven by electric engines (elec) or whether they were gas driven engines, whether the pumps had variable speed capability, and whether the station had drag reducing agents introduced in the discharge. Y/N in Table 2 means yes or no for flow control, variable speed, and DRA meaning if it's yes (Y) the station has it implemented and if it's marked no (N) the station does not have that capability.

Table 2 – Pumping Station Information

Station	# of Units	Flow Control (Y/N)	Elec/Gas (E/G)	Variable Speed (Y/N)	DRA (Y/N)
1	2	N	E	Y	N
2	2	N	G	Y	N
3	1	Y	E	N	Y
4	2	N	G	Y	Y
5	1	N	E	N	Y
6	1	N	E	Y	Y
7	1	Y	E	N	Y
8	2	N	E	N	Y

Problem Statement

For the pipeline system when a manipulated variable is changed it can have an affect on the entire downstream production so it's important to balance the changes a user can make to each pumping station and the constraints that exist on each station and the overall pipeline. The end user wanted to focus on the cost of the electrical energy and the cost of the DRA and be able to calculate the cost per barrel to transport the liquid from one end of the pipeline to another.

Initial Data

For modeling, simulation, and optimization, the following initial data was collected:

- Pump inputs (manufacturer pump map, flow, suction pressure, discharge pressure, temperature, and impeller diameter)
- Oil properties in pseudo-components (refer to Table 3)
- Electric and gas/diesel engine inputs (from manufacturer datasheets)
- Station flow and pressure
- Piping geometry and elevation changes (P&ID's with pipe diameters, pipeline elevation changes, ambient temperature, and pipeline material)
- Control strategy for pumping stations (two units in series, VFD control, pressure throttling control)

Table 3 describes the oil component, the molecular weight (Mole Wgt), the density, and the fraction of the component as a part of the total fluid.

Table 3 – Oil Properties

Oil Component	Mole Wgt	Density (lb/ft^3)	Fraction
LPG	59	36.1708	0.023844
LTENDS	71	39.9332	0.007193
NAP1	79	42.3528	0.027338
NAP2	109	47.2207	0.216313
KERO	157	50.2804	0.129844
LDIE	225	53.6362	0.226254
DIES	232	53.8643	0.253994
HDIE	235	53.9794	0.267729
TCUF	378	57.0306	0.192302
ATMR	506	59.6399	0.355396
LVGO	391	57.2119	0.1662
HVGO	554	59.1667	0.057111
VAC3	778	62.8936	0.146962
VAC2	843	63.7299	0.118162

Table 4 shows the initial system in the data and the baseline month for running the algorithm. The initial system data starts with describing the station number, the suction pressure, the discharge pressure, the flow going through the station, and the DRA.

Table 4 – Initial System Data

Station	Suct Press (PSIG)	Disc Press (PSIG)	Flow (bbl/hr)	DRA (ppm)
1	75	1000	4123	N/A
2	315	945	4046	N/A
3	200	845	4167	24
4	110	950	4020	15
5	135	850	4113	15
6	140	915	4102	22
7	215	1010	4098	12
8	75	810	4060	29

Now that the live simulation is set up and achieved a simulation result to field result of close to 1% the optimization algorithm is run with the model.

Results

The goal of the solution is to give a live cost per barrel for operating the pipeline and to reduce the cost per barrel. After an accurate simulation and the optimization was running for 3 months the suggested setpoint output is displayed in the table below. The table is taken from the end of April while Table 4 was taken in the month of February.

Table 5 – Optimized Suggested Set Points

Station	Suct Press (PSIG)	Disc Press (PSIG)	Flow (bbl/hr)	DRA (ppm)
1	98	1046	4509	N/A
2	312	1044	4328	N/A
3	228	1005	4256	8
4	158	989	4423	5
5	168	928	4489	5
6	185	1011	4392	4
7	222	1030	4426	5
8	114	857	4385	6

With the optimization suggestion set points shown in Table 5 the end user saw that the largest difference in the initial time the application was turned on into 3 months running it is the pressure in the pipeline and the DRA set points. In the initial system the DRA was quite a bit higher and the pressure was lower. The algorithm had the cost of the electricity of the gas/diesel as well as the DRA. Since the DRA is more expensive it suggested to run the pumps harder and to use less

DRA to hit the objective function of the cost per barrel to be minimized. Below is the weekly chart when the algorithm was implemented.

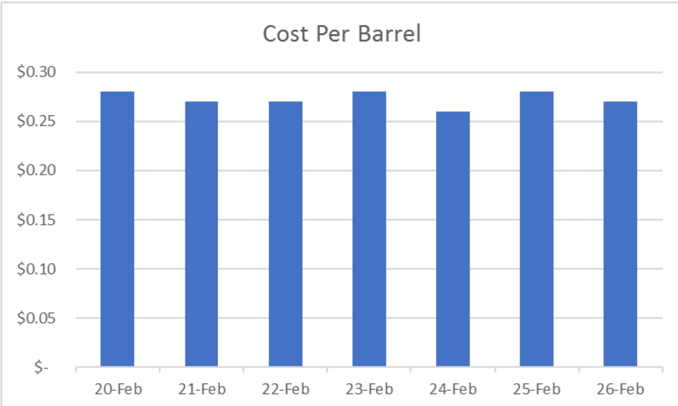

Figure 6 – Cost per Barrel in February

The cost per barrel was close to $0.28 per barrel while it was averaging about 4100 bbl/day. At the end of the 3-month period the cost per barrel were able to drop to about $0.12 per barrel.

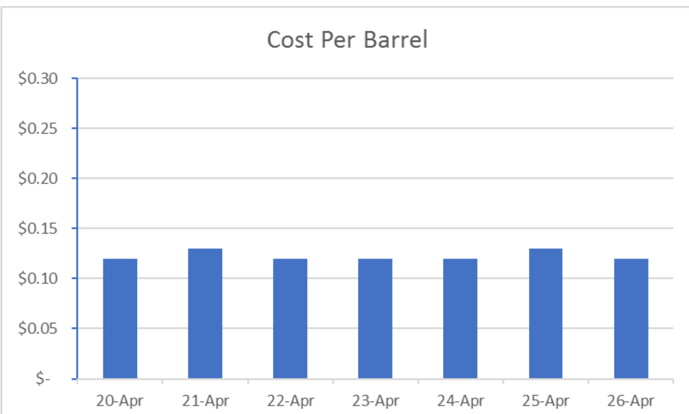

Figure 7 – Cost per Barrel in April

By optimizing the cost per barrel, the system suggests pushing the pumps to the pressure limits and pushing the pipeline to it's pressure limits and scaling back on amount of DRA injection.

CONCLUSIONS

With having the case study results, the optimization techniques can suggest manipulated variables in real-time to help minimize the cost per barrel. Pumps with variable speed or stations with throttle control can offer a wider operating range and be able to provide additional savings opportunities. The higher flow rate in the month of April was not due to the suggested set points, but due to an increase in production from the month of February to April. Future work includes having a more detailed cost model to be added to the system. The cost model was a daytime rate and a nighttime rate for the electrical cost and the gas and diesel cost did not change. The next step is to add initial daytime rates, initial nighttime rates, along with secondary day and nighttime rates where if power consumed goes over a certain contracted period it will be considered. Another important aspect is the start up for electrical motors is charged at a different rate than continuously having a motor run and adding start up cost to the pump along with just the operating pump will be necessary for a more detailed model and cost.

AUTHOR BIOGRAPHIES

Vadim Shapiro is co-founder and President of Statistics & Control, Inc. He manages all aspects of engineering, including development of the company's *OptiRamp*® Advanced Process Control software. Vadim has over 25 years' leadership experience in systems and software engineering, project management, and product development in the field of turbo machinery control, advanced process control, and power management systems. He holds six patents in the areas of turbomachinery control and advanced process control, with several applications pending.

John Hooker is a controls engineer and the Engineering group manager at Statistics & Control, Inc. He has a Bachelor of Science in Aerospace Engineering from Iowa State University. Over the past 9.5 years, John has participated in several global projects in the oil & gas and power generation sectors and has implemented numerous applications for control solutions, equipment monitoring, design testing, data analysis, and brownfield optimization.

Dr. Aaron C. West is a Software Engineer working at Statistics & Control, Inc. He has a Bachelor of Arts in Chemistry from Augustana College, Bachelor of Arts in Biology from Augustana College, and Doctor of Philosophy in Physical Chemistry from the Iowa State University of Technology. Aaron has over 10 years of experience in the development and use of computer software for modeling complex physical processes.

FIGURES

Table 1 – Symbols (Notation)

Symbol	Descrioption
A	Cross-section area
Bbl	barrel
C	Speed of sonic velocity
c_v	Specific Heat at constant volume
dPdyn	Dynamic pressure difference across pump
dPstat	Static pressure difference across pump
dPtot	Total differential pressure across pump
D	Diameter of the pipe
DRA	Drag reducing agent
Δt	Computation scan time
η	Efficiency
ρ	Density
g	Acceleration due to gravity
H	Head
hr	Hour
L	Pipe length segment
M	Mass Flow
Mole Wgt	Molecular Weight
MW	Hydraulic power
MWs	Shaft power
μ	Viscosity
N	Speed
P	Pressure
Ppm	Parts per million
PSIG	Pressure per square inch gauage
Q	Volumetric Flow
T	Temperature
VFD	Variable frequency Drive
w	Flow velocity