Texas Cattle Feeders Association
Oklahoma State University
Biosystems & Agricultural Engineering
Fact Sheet Series for
Cattle Feedlot Operations

Fact Sheet #1

BOILER BLOWDOWN MANAGEMENT AND HEAT RECOVERY

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Introduction

Boilers produce steam and/or hot water as their primary task. To do this, the boiler must take in water from some source (usually utility water), convert to steam, and distribute the steam to some process (Figure 1). As the steam is used, condensate forms. This condensate may or may not be returned to the boiler. Steam is also lost in processes and steam leaks. One of the end results of this on-going process is that make-up water is added to the boiler.

![Figure 1. Generic diagram of steam boiler. Fire tubes are usually inside the main boiler vessel or “drum”. (Steam-Boiler.org)](image)

The make-up water that is added to the boiler is typically utility or well water. This water will have varying amounts of minerals and chemicals (calcium, sodium, magnesium, etc.). In a round-about way, we can think of the boiler as a form of water distiller. As make-up water is added to the boiler to compensate for the process water losses, the relative amounts of minerals and chemicals increases or accumulates in the boiler drum. For large boilers running many hours with considerable make-up water, the minerals, or “mud” can accumulate and completely clog the boiler in a few days.

To combat this accumulation of minerals in the boiler drum, boiler designers have incorporated various mechanisms to prevent minerals from stopping the boiler operations. There are two main solutions. We could improve the quality of the incoming water via filtration (i.e., RO) to reduce blowdown or, we could use some of the steam energy to remove the mud from the boiler drum. Water filtration systems are expensive and must be maintained. We will consider the common method of using steam pressure to reduce boiler drum mud in this fact sheet.

This process is known as “blowdown”. Boiler contaminants tend to accumulate at the bottom of the drum (mud) and some float on the top of the water level (scum). A “bottom or mud blowdown” is a
method by where an amount of steam is used to partially stir up the bottom mud and then a valve on the bottom of the drum is opened and the muddy water is blown out to the drain. A “top” or “skimming” blowdown shoots a jet of steam across the top of the water level and this pushes the top scum over to a purge valve where it is also blown into the drain (Figure 2). Often (depending on the mineral content of the makeup water), the top blow down is continuous. Automatic controls can operate these valve systems by monitoring the drum water conductivity which is a good proxy for the mud content of the drum. Timers are sometimes also used. In some cases the blowdown is done daily by hand on a timed schedule.

![Figure 2. Boiler Blowdown System (AEE)](image)

**Heat Recovery from Blowdown**

Regardless of the method of controlling the top and bottom blowdown, considerable energy is lost down the drain when blowdown occurs. Depending on the local water quality, blowdown can be between 1-10% of the total steam production. This is a significant amount of steam and energy. We have to remember that the blowdown is essentially live steam and hot water being sent down the drain. A typical boiler might operate at 100 psia\(^1\) pressure. The saturation temperature at this pressure is

\(^1\) 85 psig
about $328^\circ F$. The energy content of the steam at these conditions is 1,187 Btu/lb and the energy content of the pressurized liquid water is 299 Btu/lb. The point here is that boiler blowdown is a loss of considerable energy that could be used to improve the efficiency of the boiler or used directly in some other process. Yet, we still need to do the blowdown to keep the drum clean.

Blowdown heat recovery is straightforward to understand. For this example, we will assume that the blowdown controls are operating the blowdown process correctly (this should be checked actually). We will also assume a continuous blowdown for the top or skimming operation. We will assume that the bottom blowdown is occurring at some regular interval as the drum water continuity measurement reaches some point which triggers the bottom blowdown process.

As the continuous blowdown steam and water leave the drum, they pass through a heat exchanger to capture some portion of the thermal energy that would otherwise be wasted. This waste heat can be used to preheat the incoming make-up water (Figure 3). This is a feedback loop that brings thermal energy back into the boiler system. The incoming make-up water is typically about $60^\circ F$. We know that the boiler needs to get this water to about $328^\circ F$ to form steam (100 psia) – so any increase in the incoming water temperature - is energy we do not have to add from fuel. Essentially, you have already paid for the fuel to produce this heat – let’s reuse it before sending it down the drain. This is a direct dollar savings in avoided fuel costs.

![Figure 3. Blowdown and Heat Recovery (Steam-Boilers.org)](image_url)

The same technique can be used on the bottom blowdown. The main difference is that bottom blowdown is usually not continuous (hopefully not). Therefore we need a control on the bottom blowdown heat exchanger and make-up water valve to operate only when bottom blowdown is occurring. This is fairly straightforward and done with a switch signal from the bottom blowdown
controller. As with the continuous blowdown heat recovery, as hot liquid sent to the drain, part of its thermal energy is recovered to preheat the incoming makeup water or sent to some process needing heat.

**Flash Steam Recovery**

When the bottom blowdown purges liquid from the boiler, it is at high temperature and pressure. When this liquid reaches a lower pressure, we will generate flash steam. This is why blowdown going to the drain is usually easy to spot because of all the steam generated. So, we can recover a lower pressure steam from this waste stream as it flashes. This lower pressure steam (say 50 psia) can be used in certain processes such as space heaters or deaerators. If we maintain a pressurized condensate recovery system, we can bring the flashed steam directly back to the make-up water tank (Figure 3). As with all heat recovery, we have to match the timing of this steam (energy) to a coincident need such as the space heater. If there is no need for space heat when the bottom blowdown occurs, we could simply preheat the incoming makeup water as described above.

![Flash Steam Recovery System](image)

**Figure 3. Flash Steam Recovery System (AEE)**

**Amount of Energy Recovery Possible**

The worse the incoming water quality (total dissolved solids-TDS), the more opportunity for blowdown heat recovery as the blowdown systems will be operating for longer time periods. Remember however that we are only recovering a portion of the energy lost in the blowdown so this is not an endorsement for poor quality make-up water. It would be better to never do blowdown at all. This is also why proper
condensate recovery is important – you are returning clean, distilled water to the boiler (see fact sheet on condensate recovery).

Typically, the first step in determining the potential blowdown heat recovery is to estimate the amount of blowdown that is occurring. There are a variety of ways to do this. We will look at a fairly straightforward method to determine percent blowdown.

**Example with Economics**

Let us assume we have a 300 HP boiler (10 MMBtu/hr) operating at 100 psig for 8,700 hours per year. We assume a heat exchanger efficiency of 85%. Assume a natural gas cost of $5.00/MMBtu (MCF). Assuming the boiler is 80% efficient, this boiler will produce about 10,350 lb_{steam}/hour. If the continuous blowdown is set at 900 lb_{steam}/hour the percent blowdown is:

\[
\text{% Blowdown} = \frac{900 \text{ lb/hr}}{900 \text{ lb/hr} + 10,350 \text{ lb/hr}} = 8\%
\]

<table>
<thead>
<tr>
<th>Blowdown Rate, % Boiler Feedwater</th>
<th>Heat Recovered, Million Btu per hour (MMBtu/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>0.45</td>
</tr>
<tr>
<td>4</td>
<td>0.9</td>
</tr>
<tr>
<td>6</td>
<td>1.3</td>
</tr>
<tr>
<td>8</td>
<td>1.7</td>
</tr>
<tr>
<td>10</td>
<td>2.2</td>
</tr>
<tr>
<td>20</td>
<td>4.4</td>
</tr>
</tbody>
</table>

Based on a steam production rate of 100,000 pounds per hour, 60°F makeup water, and 90% heat recovery.

**Table 1. Boiler Blowdown Heat Recovery (U.S. Dept of Energy, EERE)**

We now take the 8% blowdown to the EERE Table 1 (above). We see that 8% blowdown at 100 psig yields 2,000,000 Btu/hr for every 100,000 lb/hr input. Therefore, the equation for our 300 HP boiler would be:

\[
\text{Annual Energy Savings} = \left[2\text{MMBtu/hr} \times \frac{10,350 \text{ lb/hr}}{100,000 \text{ lb/hr}} \times 8,700 \text{ hr/yr} \times 0.8 \times 0.85\right]
\]

\[
\text{Annual Energy Savings} = 1,913 \text{ MMBtu/year}
\]

\[
\text{Annual Cost Savings} = \text{Annual Energy Savings} \times \text{Fuel Cost} = 1,913 \text{ MMBtu} \times 5.00/\text{MMBtu}
\]

\[
\text{Annual Cost Savings} = $9,567/\text{year}
\]

This is a significant savings that will occur year after year. As the price of gas rises in the winter (and over time generally) the savings will increase. We did not include the bottom blowdown that might add
other 1-2 % points on the blowdown rate. If the cost to add the blowdown recovery equipment was about $15,000, the simple payback would be:

\[
\text{Simple Payback} = \frac{\text{Investment}}{\text{Savings}} = \frac{[$15,000]}{[$9,567]} = 1.6 \text{ years}
\]

**Summary**

Boiler blowdown is one of the main methods of ensuring that the boiler drum is kept clean of accumulated minerals (mud). Unfortunately, blowdown also uses considerable boiler energy because steam is the working media used to push the contaminants out. There are heat recovery methods of recuperating much of the wasted energy though and save money on fuel costs.

The systems described in this recommendation are often suggested by boiler manufacturers these days. The best time to implement this is when purchasing the equipment new. However, we can see that even a retro-fit can have excellent economics. When combined with other boiler improvements such as better burner controls, significant fuel savings are possible.

**References:**

- Association of Energy Engineers (AEE): CEM 5-day training series
- [http://www.steamboilers.org/](http://www.steamboilers.org/)
- Bill Quisenberry, Plains Plumbing Co. LLC, Amarillo, Texas.
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Fact Sheet #2

INCREASE OVERALL BOILER STEAM SYSTEM EFFICIENCY BY USE OF DIGITAL BURNER CONTROLS (MODULATING)

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Introduction

Steam boilers are combustion devices not unlike internal combustion engines in many ways. Both use a fuel that is mixed with air and combusted. Both devices have the need for control of air/fuel ratios to function properly. Problems occur when boiler or engines experience “lean” or “rich” fuel mixtures. There is also similarity in the control methods used to throttle both types of machines.

Boilers typically use natural gas burners to heat the water in the boiler drum. These burners produce flames and hot exhaust gases that pass through fire tubes immersed in water in the boiler drum \(^1\) (see Figure 1.).

![Figure 1. Fire tube boiler (Castelnuovo)](image)

The burners are usually rated in millions of Btu’s per hour (e.g., 5 MMBtu/hr) but can be throttled below this maximum rating. Another function of the burner is to maintain the correct, or near “stoichiometric” air and fuel ratio. The stoichiometric ratio is the exact ratio at which the combustion equation of natural gas is consumed completely to produce by products of heat, CO2 and water (see Equation 1).

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\(^1\) Water-tube boilers have water inside the tubes but the principle is the same.
We can approximate natural gas with methane (CH4) in the combustion relationship.

\[
\text{CH}_4 + 2\text{O}_2 \rightarrow \text{CO}_2 + 2\text{H}_2\text{O} \quad \text{(Eq.1)}
\]

By working out the molecular weights we find that the stoichiometric air to fuel (AFR) ratio for natural gas (methane) is about 14 to 1. If the burner could maintain this AFR, the burner would be running as efficiently as possible. In reality, boiler tuners tend to set the AFR slightly on the lean, or excess air (O2) side in order to guarantee the consumption of all fuel and so as to not produce any carbon monoxide (CO) which is highly toxic (to the right of bottom axis in Figures 2 & 3). Once a burner is adjusted and tuned it will begin to go out of tune without further adjustment. Sometimes the burner goes out of tune slowly, but it is inevitable. Sometimes the burner begins to bring in more excess air or it may go out of tune by running rich (to the left of the stoichiometric point in Figures 2 & 3). Regardless, the efficiency of the burner and boiler begin to suffer.

![Figure 2. Graph showing stoichiometric curves air/fuel combustion](image-url)
Boiler operators tend to think in terms of “excess air” expressed as a percentage (Figure 3). The amount of excess air can usually be set by the operator. Excess air is directly related to the percent of oxygen detected in the exhaust gases also.

Typically, the efficiency of the boiler is measured with an exhaust gas analyzer measuring the flue gases. The analyzer is usually measuring levels of oxygen (O2) as this is a good proxy for boiler efficiency. This is also why automotive fuel injection systems have O2 or “lambda” sensors placed in the exhaust system. A boiler in good tune will have an O2 reading of about 1-2%. It is not unusual to find boilers running at 7-9% O2.

Roughly, the boiler efficiency drops one percent for every 2% O2 increase (see Table 1 below). Therefore, a boiler running at 10% O2 if tuned to 2% O2 may experience an efficiency increase of about 4%. This may not sound like much of an improvement (4%) but the old adage that “a small bit of a very large number is still a large number” applies here. A 500 HP boiler running for 8,000 hours per year will use 132,000 MCF (1,000 cubic feet) of natural gas. At $5.00/MCF this is $660,000 per year in fuel costs.

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2 Be aware that some locations have local codes requiring O2 readings no lower than 3% unless automatic trim controls are used.
Four percent of this is $26,400 per year in savings to keep the boiler tuned. If the company tuned the boiler once a year the savings might be less depending on how fast the boiler goes out of tune. Regardless, the potential for energy and cost savings is large.

Table 1. Table showing boiler efficiency versus excess air and O2 % (U.S. Dept of Energy, EERE)

The same situation existed with automobiles in the 1970s. Mechanical carburetion, which had to be periodically tuned, was not able to keep up with strict air pollution and fuel economy regulations. These devices will slowly go out of tune (ask any classic car buff). What was needed was a control system that could sense deviation from a stoichiometric set point and automatically adjust the air fuel ration back to optimum. This is known as electronic fuel injection (EFI). EFI uses the exhaust O2 sensor to adjust the air fuel ratio going into the engine. Not only did EFI lower the overall air pollutants but it increased the fuel economy (and horsepower to some extent) of the vehicles. In some cases the improvements were dramatic and accomplished by digital AFR control.

Modulating Burner Control

The same type of control methodology is available in boiler combustion control and is sometimes called “burner modulation” or “linkage less controls”. Basically the burners have electric air/fuel ratio controllers that accept various signals from the process. For example, if the exhaust stack O2 sensor is indicating a deviation from some set-point such as 2% O2, the burner modulating control will adjust the AFR until the 2% O2 level is achieved. This is sometimes described as “oxygen trim”. Because this is a digital control this adjustment will be rapid. As demand on the boiler (steam load) fluctuates, the AFR can also be momentarily affected. However the modulating burner will instantly adjust to this. The modulating burner controls try to optimize the boiler for all operating conditions. This really is a “win-win” situation and in retrospect appears quite logical.

As in cars, boiler maintenance is improved with automatic AFR control because the boiler is always in a state of fine tune. Fire tubes do not accumulate soot as fast and the temperatures in the boiler and steam distribution system are more even. Process quality can also improve because the steam temperature and pressure is more consistent.
One of the few drawbacks to digital modulating burner control (besides first costs) is that boiler operators may not have the training needed to operate automatic digital controls and workstations. The solution is obvious and probably inevitable anyway. Most facilities employ a variety of digital devices such as variable speed drives and PLC’s therefore the additional training for digital burner controls will not be that big a stretch.

**Energy and Cost Savings from Modulating Controls**

As with most energy opportunities, the possible savings is largely dependent on the current situation. The author has seen boilers where the facility operator cannot remember if the boiler was tuned in the past 10 years. An O2 test showed 10% O2. This boiler had probably wasted tens of thousands of dollars over the years. Other boilers have been recently tuned and when tested, showed low O2 levels. In most cases however, the boilers with old mechanical fire controls experience efficiency drops at part-loads.

**Again, depending on the current setup, overall fuel savings of 3% would not be unusual**³. For example, a 300 HP boiler at 80% efficiency and running 8,000 hours per year would consume:

$$300 \text{ HP}_{\text{boiler}} \times (33,475 \text{ Btu/hr/HP}_{\text{boiler}}) \times (1/0.8) \times (8,000 \text{ hours/yr}) = 100,425 \text{ MCF/year}$$

At a price of $5.00/MCF this is: 100,425 MCF/year x $5.00 = $502,000/year

Three percent of this is: $15,064 per year savings

If the boiler controls cost $12,000 installed, this is a less than one year payback.

**Sequencing**

For facilities with multiple boilers, the controls should help to optimize the scheduling and running of the boilers. This is especially true if all the boilers feed a common steam manifold. Problems also occur if boilers are different sizes. Typically, we want the largest boiler to provide a steady baseload at near full load. Variation above the base load can be handled by a smaller boiler that is easier to throttle. Sequencer controls can do this optimization assignment task automatically.

Another task that sequencers can do is spreading the run-time evenly between several boilers so that wear and tear does not accelerate the breakdown of a particular boiler. Sequencer control can provide this task while also optimizing other functions.

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³ [http://www1.eere.energy.gov/industry/bestpractices/pdfs/steam24_burners.pdf](http://www1.eere.energy.gov/industry/bestpractices/pdfs/steam24_burners.pdf)
Safety and Requirements

All controls described must be installed such that safety is not compromised. All equipment and processes must also meet all applicable codes and environmental regulations. For example, controls need to be cross limited to start purge air before fuel is introduced and ignited (explosion hazard).

Summary

Boilers are machines that use a considerable amount of fuel. In order to optimize the fuel economy, boiler need to be in a fine state of tune. Old mechanical fire control systems start to drift out of tune immediately after being set. Modern digital boiler fire control systems can keep a boiler closer to optimum tune at all times and save fuel costs.

Retrofitting boiler controls will take time and effort however the paybacks can be rapid depending on the current condition of the boiler controls. For multiple boilers that run long hours, sophisticated digital burner and sequencer controls are recommended. While not inexpensive, modern controls can pay back rapidly.

References:

- Association of Energy Engineers (AEE): CEM 5-day training series
- Bill Quisenberry, Plains Plumbing Co. LLC, Amarillo, Texas.
Texas Cattle Feeders Association  
Oklahoma State University  
Biosystems & Agricultural Engineering  
Fact Sheet Series for  
Cattle Feedlot Operations  

Fact Sheet #3  

Boiler Heat Recovery Using Exhaust Economizers  

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Introduction:

A natural gas boiler looses about 18-22% of the fuel energy up and out the exhaust stack (Figure 1). This is an invariable result of the process of combustion. If we could capture some of the waste heat before it escapes, we could improve the overall efficiency of the boiler. In turn, we could save energy costs.

![Boiler energy balance](image)

**Figure 1. Boiler energy balance**

This is precisely what a boiler economizer does. The name “economizer” is a bit old fashioned but is describing the energy and cost recovery. Do not confuse a boiler economizer with an air conditioning system economizer – they are completely different devices. Other names for boiler economizers include “recuperator” and “regenerator”. Normally, the device called a recuperator is used to pre-heat the boiler combustion air. This device is not used as often as the economizer as it interacts with the burners and complicates the air to fuel ratios. We are interested in boiler economizers here.

Essentially, the economizer is a heat exchanger that is placed into the boiler exhaust stream (Figure 2). The economizer is usually used to provide heat (thermal energy) to the boiler feed (or “make-up”) water. The hotter you can get the water coming into the boiler – the less natural gas fuel you need to use to get this water to boil and make steam. Basically, the economizer is using energy that you have already paid for to provide input energy into the boiler. It’s a feedback loop - “pulling yourself by your own bootstraps”.

The processes the steam is being used for largely determine how much make-up water is added. Food or animal feed processes typically lose water (moisture added in the product) and therefore tend to add considerable “utility water” as make up to the boiler. Make-up utility water is usually about 60F°. Often
there is no condensate or heat recovery and so this is the temperature of all the water entering the boiler. Now, this water must be heated to 350-450°F (depending on boiler pressure). This is a change in temperature of 290-390°F. If we heated the make-up water with an economizer to 160°F the change in temperature would only be 190-290°F. This is a considerable savings in fuel usage and costs.

![Diagram of economizer on boiler exhaust stack heating make-up water](image)

**Figure 2. Economizer on boiler exhaust stack heating make-up water**

As the economizer removes heat energy from the exhaust stack, the temperature of the exhaust is lowered. This would seem to be a non-issue except for one possible side effect. If the exhaust gases are cooled too much, acids can precipitate out of the exhaust. This can cause corrosion problems for the economizer and flue. Typically, flue gases condensate acids at about 240°F. This usually sets the lower temperature range for economizer operations.

The amount of energy the economizer can recover depends on several factors such as flue exhaust temperature, flue gas flow rate, and temperature of the make-up water. Very high exhaust temperatures such as 700°F will help the economizer to recover considerable heat energy but may be a sign of other serious problems such as soot or scale build-up on heating tubes. Typically, economizers on a healthy boiler will be operating with flue temperatures in the 400-500°F range.
Fuel Savings Examples:

A useful rule of thumb is that boilers equipped with economizers can generally expect a 1% increase in boiler efficiency for every 40°F drop in flue gas temperature (Cleaver Brooks). This assumes that the drop in flue temperature is due to economizer heat recovery. Again, this also depends on the process and rate of condensate recovery, etc.

For example, let us use a 5 million Btu (MMBtu) per hour boiler running a flue temperature of 450°F. This boiler is fully loaded during operations. The boiler’s efficiency has just been tested at 78% and it runs 4,000 hours per year. Natural gas costs about $6.00 per MCF\(^1\) (MMBtu). An economizer is being considered that would lower the flue temperature to 280°F and cost $17,000 installed. Let’s see how the numbers work out.

Cost to run the boiler for one year without economizer:

Energy Used Per Year without Economizer

\[
\text{Energy Used Per Year} = \left(\frac{\text{Boiler Usage Rate} \times \text{Hours per Year}}{\text{Efficiency Rate}}\right)
\]

\[
=\left(5 \text{ MMBTu/hour} \times 6,000 \text{ Hours/Year}\right) \div 0.780
\]

\[= 38,461 \text{ MMBtu (MCF) per Year} \]

Cost to Run Boiler Without Economizer

\[
= (\text{Energy Used per Year}) \times \text{(Cost of Natural Gas)}
\]

\[
= (38,461 \text{ MCF/Year}) \times ($6.00/\text{MCF})
\]

\[= 230,769 \text{ per Year} \]

Cost to run the boiler for one year with economizer:

Percent Efficiency Improvement

\[
\text{Percent Improvement} = \left(\frac{\text{Change in Temperature}}{40}\right)
\]

\[
= \left(\frac{450°F - 280°F}{40}\right)
\]

\[= 4.3\% \text{ Therefore new boiler efficiency} = 78.0 + 4.3 = 82.3\%
\]

---

\(^1\) MCF = 1,000 Cubic Feet of Natural Gas =1,000,000 Btu = MMBtu
Energy Used Per Year with Economizer

\[
\text{Energy Used Per Year with Economizer} = \left(\text{Boiler Usage Rate} \times \text{Hours per Year}\right) \div \text{Efficiency Rate}
\]

\[
= \left(5 \text{ MMBTu/hour} \times 6,000 \text{ Hours/Year}\right) \div 0.823
\]

\[
= 36,452 \text{ MMBtu (MCF) per Year}
\]

Cost to Run Boiler with Economizer

\[
\text{Cost to Run Boiler with Economizer} = (\text{Energy Used per Year}) \times (\text{Cost of Natural Gas})
\]

\[
= (36,452 \text{ MCF/Year}) \times ($6.00/\text{MCF})
\]

\[
= $218,712 \text{ per Year}
\]

Energy and Dollar Savings from Economizer

\[
\text{Energy and Dollar Savings from Economizer} = (38,461 \text{ MCF/Year} - 36,452 \text{ MCF/Year}) = 2,009 \text{ MCF savings/Year}
\]

\[
= (2,009 \text{ MCF/Year}) \times ($6.00/\text{MCF}) = $12,054
\]

Economizer Economic Payback

\[
\text{Economizer Economic Payback} = (\text{Investment}) \div (\text{Savings})
\]

\[
= ($17,000) \div ($12,054/\text{Year})
\]

\[
= 1.4 \text{ year}
\]

So, for our simple example, an economizer on this boiler would payback in less than two years. As you can see from the calculations the economics of the economizer are centered on boiler size, heat recovery (temperature drop), and operating hours. This is reflected in the summary table 1.

<table>
<thead>
<tr>
<th>Initial Stack Gas Temperature, °F</th>
<th>Recoverable Heat, MMBtu/hr</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Boiler Thermal Output, MMBtu/hr</td>
</tr>
<tr>
<td></td>
<td>25</td>
</tr>
<tr>
<td>400</td>
<td>1.3</td>
</tr>
<tr>
<td>500</td>
<td>2.3</td>
</tr>
<tr>
<td>600</td>
<td>3.3</td>
</tr>
</tbody>
</table>

Based on natural gas fuel, 15% excess air, and a final stack temperature of 250°F.

Table 1. Economizer Heat Recovery Table for Large Boilers (U.S. Dept of Energy – EERE)
If an economizer were combined with other recommendations such as blowdown recovery, insulation and burner controls, the savings could be even greater. These other recommendations are covered in other fact sheets in this series.

Summary:

Boiler economizers are now becoming more common as new equipment on boilers. Considering how logical their benefits are – this is not unusual. For boilers without economizers, operators should run the economics and consider these waste energy devices as a retrofit.

References:

- Bill Quisenberry, Plains Plumbing Co. LLC, Amarillo, Texas.
Texas Cattle Feeders Association  
Oklahoma State University  
Biosystems & Agricultural Engineering  
Fact Sheet Series for  
Cattle Feedlot Operations

Fact Sheet #4

INSULATE BOILER EQUIPMENT AND STEAM DISTRIBUTION LINES TO SAVE ENERGY

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Introduction:

Steam boilers are in the business of delivering heat and pressure. Mostly, the boiler is delivering heat energy to some process. Therefore, it is surprising but not unusual, to find bare metal steam distribution lines and other surfaces running for long distances between the boiler and end-processes.

There are several problems associated with uninsulated steam surfaces. The first is obvious: loss of temperature and energy to the surrounding air. This causes the boiler to use more fuel to make up for this temperature loss. The second problem is that when steam cools in the distribution system it changes phase back to liquid water or condensate. This can cause a host of problems in the steam distribution system.

Another problem with uninsulated steam surfaces is the possible scalding hazard. Uninsulated steam lines can easily reach 300 degrees F. This can produce third degree burns instantly on skin.

Other than the actual steam lines, support equipment such as make-up water tanks need to be insulated if hot condensate is being returned (as it should) or if the boiler is using an economizer to preheat the make-up water. It is a shame to go to the trouble to recover this valuable heat only to lose it with an uninsulated make-up water tank. As implied above, condensate return lines should also be insulated. Figure 1 shows an infrared image of an uninsulated boiler make up water tank radiating heat. This lost heat will have to be added back into the system by burning more fuel.

Figure 1. Infrared image of an uninsulated boiler feedwater tank
Any metal surface that is radiating heat from steam within, is a candidate for adding or replacing insulation. Examples are the large valves used on the main steam lines and manifolds. Figure 2 shows one of these large steel valves radiating heat. Typically, valves are not insulated because maintenance personnel are not aware of special “lace-up” valve covers or feel the covers would interfere with maintenance tasks. As mentioned, special covers are available to insulate almost any size or shape of steam valve (see Figure 3 below). Figures 4 through 6 show various uninsulated surfaces radiating valuable heat.

Figure 2. Infrared image of an uninsulated main steam delivery valve on top of a boiler
Figure 3. Photo of special “lace-up” steam valve wrap

Figure 4. Front and back view of the boiler makeup water tank with failed insulation
Figure 5. Uninsulated steam lines radiating heat to the air

Figure 6. Uninsulated steam lines radiating heat to the air
Recommended Action

The recommended actions are to insulate the surface of the make-up (MU) water tank, any condensate return lines, and the steam valves with fiber glass or similar insulation. The steam valves can be insulated with specially made removable “caps”. This will prevent excess heat loss from all these systems and promote energy cost savings. Based on past experience it is estimated that the insulation will help in reducing 80-90% of the distribution heat loss and thus reducing the amount of energy needed to run the final process (see Figure 7).

![Heat Loss Reduction from Insulation](image)

**Figure 7. Chart showing diminishing return on heat loss reduction versus insulation thickness**

The calculations used to show the heat loss; savings from insulation and economic payback are somewhat complicated and better represented by summary tables. Table 1 is based on one cost of natural gas – which for this example was $6 per MCF ($0.60 per Therm). The higher the cost of fuel, the faster the payback of insulation projects. Because the payback is an inverse linear relationship to the cost of fuel, doubling the cost of fuel ($12/MCF) would cut the time to payback the cost of insulation by one half.

Table 1 is also based on something known as the insulation “economic thickness”. This term is describing the fact that after the first couple of inches of insulation the heat loss drops to about 5% and then levels off at about 2% regardless of amount of insulation (see Figure 7 above). The first inch of insulation stops about 80% of the heat loss. There is a point of diminishing return.
(economically) for insulation thickness. For this table (Dept of Energy), the economic thicknesses were determined by minimizing costs over a seven year period (EERE ORNL/M 4678). The bottom line is that the insulation thicknesses were between 1 and 2 inches.

The thing to notice from the heat loss table is how much the heat loss increases as the diameter of the uninsulated steam line increases. Also, the heat loss increases rapidly with increases in pressure.

<table>
<thead>
<tr>
<th>Steam Line Diameter Inches</th>
<th>Steam Pressure, PSIG</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>15</td>
</tr>
<tr>
<td>1&quot;</td>
<td>140</td>
</tr>
<tr>
<td>2&quot;</td>
<td>235</td>
</tr>
<tr>
<td>4&quot;</td>
<td>415</td>
</tr>
<tr>
<td>8&quot;</td>
<td>740</td>
</tr>
<tr>
<td>12&quot;</td>
<td>1,055</td>
</tr>
</tbody>
</table>

Table 1. Heat loss figures based on steam system operating 8,760 hours per year (based on EERE Paper)

Economics Example:

If natural gas costs $5.00 per MMBtu (MCF) and the feedlot has 500 feet of uninsulated 1” and 50 feet of 2” diameter steam lines operating at 150 psig the heat loss from the table is:

1-inch line: $500 ft x 285 MMBtu/yr/100 ft = 1,425 MMBtu/year
2-inch line: $50 ft x 480 MMBtu/yr/100 ft = 240 MMBtu/year
Total Heat Loss = 1,665 MMBtu/year

If the boiler is 80% efficient, and the insulation reduces 90% of the heat loss, the annual cost savings from insulating the pipes is:

\[\frac{1,665 \text{ MMBtu/year} \times 0.9 \times (\$5.00/\text{MMBtu})}{0.8} = \$9,366/\text{Year Cost Savings}\]

1” Pipe Insulation Cost = $3.10/foot (Grainger Online Catalog, #199744, Dec, 2011)
2” Pipe Insulation Cost = $6.78 (Grainger Online Catalog, #200267, Dec, 2011)

Total Insulation Cost:

(500 feet x $3.10/ft) + (50 feet x $6.78/ft) = $1,550 + $339 = $1,889
Labor costs to install = 8 hours to install x $25/hour = $200

**Total Cost = $2,089**

Project Economic Payback = Cost/Savings = $2,089/$9,366 per year = 0.22 year = 3 months

This particular example paid back quite well partially because of the long run hours (24/7) and the relatively high pressure (150 psig). A more typical feedmill boiler operating at 100 psig and for 4,000 hours per year might save somewhere in the neighborhood of $2,700 with just under a year payback.

**Summary:**

Metal steam lines and make-up water tanks can lose significant amounts of heat energy to the surrounding air. The lost energy must be made up on the boiler fuel input side of the process. Essentially, these heat losses are types of parasitic or waste loads for the boiler.

The simplest method of minimizing this lost heat energy is by insulating the offending pipes and tanks. Depending on the steam temperature, area of uninsulated surface and price of fuel, the economic payback can be rapid. Even odd shaped surfaces such as steam valves (Figure 3.) can be insulated. Additionally, the insulation provides scalding safety for personnel and limits owner liability.

**References:**

Texas Cattle Feeders Association
Oklahoma State University
Biosystems & Agricultural Engineering
Fact Sheet Series for
Cattle Feedlot Operations

Fact Sheet #5
Feedlot Electric Utility Billing

R. Scott Frazier, PhD, PE, CEM
Oklahoma State University
Introduction

The first step in trying to save money on electric, gas or fuel costs is to understand how the energy usage is being billed. Petroleum products (gases and fuels) are somewhat straightforward; however, electrical energy and power billing can be confusing. It is almost impossible to be involved with trying to save energy costs if one does not understand exactly how the energy (electricity, gas, and fuel) is being billed. While natural gas billing can be influenced by weather and demand, it is the electric billing where the customer can make process changes and achieve cost savings and our discussion here will center on electricity. Often, significant cost savings can be realized by simply understanding the rate schedules and changing some aspect of a process such as start times.

Electricity is a unique energy source in that it cannot be economically stored by individual users. The utility must be able to provide whatever need there is immediately. This is known as “demand”. Not meeting this immediate demand, or capacity, can lead to widespread problems for the utility and customers. Basically, the utilities must predict the largest need in their territory and then overbuild generating, transmission and distribution equipment in order to supply this demand - plus a margin for future growth. This over-sizing of equipment is expensive and the utility recaptures this investment through various components of the electricity bill.

Another aspect of electrical energy usage is that the system demand problems tend be worse during certain seasons and times of the day. In the summer, air conditioning loads will be highest in the afternoon and evening as the sun heats residences and buildings. Also, people will be coming home from work and starting evening chores. In the winter, the electrical system may experience increased loads in the early morning and afternoon. These peak loads vary largely depending on what types of heating and cooling systems (gas or electric) make up the majority of buildings in the utilities’ territory.

In many cases, the utility systems are close to full capacity. That is, any significant additional load (demand) will strain the existing equipment such as lines and generation. Utilities use pricing methods, or signals, to encourage customers to reduce usage during periods when the utility system is nearing its peak capacity. These signals are often written into the customer’s rate schedule. Understanding the rate schedule often leads to the ability to save energy costs.

Reading and Understanding Your Electric Utility Rate Schedule

As an electric utility rate-paying customer, you have a right to read and understand your electric rate schedule (sometimes called the “tariff”). In fact it is difficult to successfully lower your electrical utility costs until you understand your rate schedule. However, few rate payers have ever actually looked at their rate schedule closely.

Many rate schedules are posted on the internet. Simply search for your electricity provider and look for “rates”, “schedule” or “tariff”. You can also call or write your utility and request a copy of the rate schedule you are on. It is better to have an actual copy in hand rather than try to copy a verbal description. Keep in mind that some customers are on special rates negotiated in the past. You must have your current rate at hand in order to understand the utility billing.
What follows is a short description of the terminology and the billing components you will likely encounter on the rate schedule and a generic example of a small commercial time of use (TOU) demand rates schedule. Rate schedules vary between utilities but are usually a combination of the pieces shown below. Your schedule may be different but this example shows some of the basics of electric rate schedule construction.

**Generic Commercial TOU Rate Schedule with Tiered Energy and Power Factor Charges**

<table>
<thead>
<tr>
<th>Rate:</th>
<th>Customer Service Fee:</th>
<th>$25.00 per customer per month</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Plus</td>
<td></td>
</tr>
<tr>
<td>Demand (kW) Charge:</td>
<td>$8.00 per month kW of billing demand</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Plus</td>
<td></td>
</tr>
<tr>
<td>Energy (kWh) Charge Summer:</td>
<td>First 10,000 kWh billed = $0.09/kWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(Summer = July 1 – Sept 30)</td>
<td>Over 10,000 kWh billed = $0.05/kWh</td>
</tr>
<tr>
<td></td>
<td>Or</td>
<td></td>
</tr>
<tr>
<td>Energy (kWh) Charge Winter:</td>
<td>First 10,000 kWh billed = $0.06/kWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(Winter = Oct 1 – June 30)</td>
<td>Over 10,000 kWh billed = $0.035/kWh</td>
</tr>
</tbody>
</table>

**Power Factor:** For measured customer power factor less than 90%, the demand charge will be the measured demand multiplied by 90% and divided by the measured power factor.

**Typical Electric Utility Schedule Billing Components**

**kWh** (Kilowatt-hours) also called: “Energy” or “Consumption”.

This is the amount of electrical energy that is used over time by the consumer. A kilowatt is 1,000 watts and a kilowatt-hour is 1,000 watts used for one hour. For example: Ten, 100 watt lamps that ran for one hour would have used 1 kWh. Think of the odometer on your car. The kWh’s are similar to the number of miles your car traveled during a certain time period.

**kW** (Kilowatt) also called “Demand”.

This is the amount of power that a customer’s facility or operation is pulling (demanding) from the utility electrical system at a given moment in time. Actually, the time period is not instantaneous but usually a 15 minute average (advantageous for the consumer). In our lamp example, the ten, 100 watt lamps are pulling 1,000 watts (1 kW) at any time they are on. Therefore, the lamps have 1 kW of demand. Demand is similar to the miles per hour needle on the speedometer telling us how fast we are going at any particular point in time.
**Power Factor** (PF) also called “Reactive Power”.

This concept is a bit complicated but basically it is a measure of how effectively the customer is utilizing the electrical energy the utility provides. You might think, “Why should the utility care how I use my electricity?” Power Factor problems on the customer’s end are a problem for the utility system also. This is a phantom load that the utility must provide but does no useful work for anyone. Power factor is a percent or fraction, less than or equal to one, and is considered bad if it is “low” (for example, a PF of 50% or 0.5 is not good). Power factor is a problem if the customer is: (1) On an account that has PF billing and (2) Has large inductive loads like big electric motors. Residential and small commercial accounts typically don’t have PF billing.

**Demand Ratchet**

This component of electrical demand (kW) billing is a way the utility attempts to get consumers to even their load during the year (month to month). In the demand billing section of your rates you may find wording such as: “In no case will the billed demand be less than seventy percent (70%) of the maximum demand established during the past eleven (11) months.” What this means is that if the customer sets a year high peak demand of 1,000 kW (larger farm/feedlot operation) in June, the minimum demand for next eleven months will be the greater of the actual demand used or 700 kW. This could be important for agricultural customers who only operate a few months a year.

**Time of Use Rate (TOU)**

This is a type of billing schedule that assigns higher costs to electricity usage (usually kWh) depending on the time of day and season. As mentioned in the introduction, this billing is done to motivate customers to move loads to different (off-peak) periods. The difference between “on” and “off-peak” costs vary. Typically the higher rates during the day will occur in the early afternoon to early evening (for example, 2:00 pm to 8:00 pm).

**Tiered Energy Charge**

Some utilities charge less per kWh – the more you use (some utilities may charge more). Regardless, this “tiered” or “block” structure will show up on your rate schedule. An example might be that the first 2,000 kWh used in a month are charged at $0.08 per kWh. Any usage above 2,000 kWh that same month is charged at $0.035 per kWh.

**Load Factor**

This is different from Power Factor. Some utilities base the charges on the customer’s load factor. Load factor is a measure that describes how level, or consistent, the customer’s electrical usage is throughout the month. For instance, a facility that used the same amount of electrical power day and night for a month would have a load factor of one. This is good from the utilities’ standpoint (easy to plan capacity). A facility that uses a significant amount of energy for a few hours, and then shuts down for long periods (for example a church), would have a low load factor. One way to calculate a monthly load
factor is to divide the month’s total kWh by the maximum measured month’s demand (kW) times 720 hours in the month.

**Example Electric Bill with Time of Use (TOU), Demand, kWh Tier, and Power Factor for a Commercial Rural Account (like a smaller feedlot).**

This is a hypothetical electric bill that demonstrates several of the concepts described above. The bill and rates are fictitious and actual bills will vary.

**Rate:** Use the generic TOU rate schedule shown above in this fact sheet

**Example Bill Calculation**

Let’s assume that this feedlot used 27,532 kWh in July with a measured demand of 120 kW. Their metered power factor was 62% (0.62). What would the bill look like?

- Customer Service Fee - $25.00
- **Demand (kW) and Power Factor**
  - Maximum of:
    - Measured demand - $8.00/kW x 120 kW = $960
  - Or...
    - Power Factor Calculation – (120 kW x 0.9)/(0.62) = 174 kW x $8.00/kW = $1,392 (This is the higher number so this is what will be billed for demand)
- **Energy (kWh)**
  - 10,000 kWh x $0.09/kWh = $900.00 (First Cost Tier Summer)
  - 27,532 kWh – 10,000 kWh = 17,532 kWh x $0.05 = $876.60 (Second Cost Tier Summer)
- Total Bill (not including taxes): $25 + $1,392 + $900 + $876.60 = **$3,193.60 (+taxes)** for month of July

**How is Understanding the Rate Structure Useful?**

Let’s look at our hypothetical feedlot operation. Knowledge of the rate schedule gives the operator several opportunities to possibly lower electrical costs. Notice, we did not explicitly say “lower electrical energy use”. We are talking about taking advantage of rate schedule knowledge here – energy conservation is different and would add to the savings.
Is there a way to lower the demand cost? Is it possible to not have as much equipment running at the same time during the month? If we can try not to run everything simultaneously, we would save energy and demand costs.

The low power factor (62%) is increasing the demand cost in this example billing month by about $432. If not corrected, this will cost the facility an additional $5,184 per year for electricity that is not doing anything. Look to the electric motors or other systems to figure out why the power factor is so low.

Maybe some operations could be done at different times of the year. Suppose that some of the work done in July could be done during other months of the year besides the three higher-rate months of July, August and September. Using the cheaper winter rates, the 27,532 kWh charge would cost $1,213.62, not $1,776.60 – a savings of $562.98 for that month. Maybe the operations cannot be done at different “off-peak” times, but you see the possible opportunity here.

If the rate schedule had a time of day cost (another type of TOU rate) that went up for six hours in the afternoon in the summer (this example did not), the operator might be able to reschedule some operations to early morning or evening. In some utilities’ territories, the cost difference between peak and off-peak time of use is significant. Ironically, the more complex the rate schedule – the more opportunities there usually are for cost savings.

Summary

Knowledge of your electric rate schedule is important in understanding how you can save money on your bills. The future of electrical utility billing will probably include new rate structures such as real time pricing. This will require that the consumer be aware of electrical usage and specifics of the bill in order to minimize costs. Understanding your current electrical rate structures is also a great way to prepare for these new billing methods and maybe save some energy costs now. If you have questions about your electric rates you can call your utility for clarification.
Texas Cattle Feeders Association
Oklahoma State University Biosystems Engineering
Fact Sheet Series for
Cattle Feedlot Operations

Fact Sheet #6
IRRIGATION PUMP SYSTEM TESTING

R. Scott Frazier, PhD, PE, CEM
Oklahoma State University
Introduction:

Pumps are widely used in a variety of locations by rural operations. Feedlots can use considerable amounts of water transported by pumping. In some locations with heavy irrigation operations, the pumping systems can comprise the majority of the energy costs. For this reason, these systems should be inspected and improved if possible.

Pump Energy Basics

The pump system curve describes the relationship between the pump flowrate (q – Gallons per Minute, gpm) and the head pressure (h – Feet, ft) for the actual pump (see Figure 1). The system curve describes the requirements the system places on the pump while the performance curves for the pump describe the relationship between the head pressure and the capacity flow rate of the pump based on the impeller diameter. Usually these curves reflect the performance at a constant and specific driver speed, rpm. The intersection of the system curve and the pump performance curve will be the operating pump for the system with the pump included. Best design practices prefer this intersection to be located close to the best efficiency point (BEP) of the pump performance curve. This also is the most energy efficient point for the pumping system to operate. Figure 1 gives an example of a system curve and pump performance curve intersection at the operation or “best efficiency point” (BEP).

Figure 1. Example pump performance and system curves.
It is somewhat rare to find older water pumping systems operating at optimal efficiency. Often these systems were not designed properly and they have degraded over time. Impellers corrode, wear and even break. Pump systems and pipes can become clogged with dirt, sediment, and mineral buildup. Often the impeller size is not properly matched to motor power or desired flow rate. The end result is wasted energy and money.

By conducting a pump test, one is able to see how far from optimal (BEP) the actual pump performance is. In general, pumping systems that are above 60% in pumping efficiency (power output of pump in flow and lift dived by power input) are considered to be in excellent condition. Pumping systems that are 49% or below, are either designed incorrectly, in poor condition, or both, and need to be replaced or repaired. A long term study (ACEEE 1999) showed the average centrifugal well pump efficiency was 55.4% in Southern California. It is anticipated that the same poor efficiency average could be found in many regions of the United States. This indicates that many pumping systems are at or below this value and therefore in the poor efficiency range. Pumps that have not been examined for over three years are possibly in the 50% performance range.

Pumping Efficiency

“You can’t improve what you can’t measure” is an old but accurate statement. The total efficiency of a fluid pumping system is a function of the flow rate which can be measured, the specific gravity of the fluid (water for irrigation), the total “dynamic head” (system pressure) and power input (also measured) which is usually the electrical power\(^1\) to an electrical motor. Let’s examine this relationship and how we might determine the efficiency. The calculated efficiency will, in turn, tell us something about the status of our pumping system and what opportunities we have to save energy and money.

Begin by looking at the required horsepower (HPw) to pump water at a certain pressure (total dynamic head, TDH) and at a certain flow rate (GPM). This relationship is:

\[
HPw = \frac{TDH \times GPM}{3,960}
\]

Where:

- \(HPw\) is the horsepower needed to pump the water
- \(TDH\) is the total dynamic head measured in feet (see TDH below)
- \(GPM\) is the flow rate of the water in gallons per minute (desired or measured)

\(^1\) Kilowatts - kW
The flow rate of the water (GPM) can be measured - maybe not easily though. In some cases we can use ultrasonic velocity measuring devices that clamp onto the outside of the piping and do not interfere with the water flow. In other cases we may put a measuring device into the water stream. Once we have the fluid velocity we can multiply by the pipe inside cross-sectional area to get an estimate of the flow rate. If this flow rate is what we need and we are satisfied, we move to the next task. That is, we are getting the flow we want – now, are we producing that flow efficiently? A very basic flow measurement can be made with a 5 gallon bucket. Begin by timing how long it takes the water flow to fill the 5 gallon bucket in seconds. Multiply this by 60 to get a ratio in GPM. This is a basic method but would be a good estimate as long as flow rates are not too high.

Total dynamic head (TDH) is a measure of the amount of resistance to flow in the system. This is usually measured in terms of “feet”\(^2\). Total head pressure usually comes from three things: amount of elevation change, length and shape of piping system, and end-use pressure requirements. There are various tables and methods of determining TDH. If we are pulling water from a well, the well depth is given in feet. Charts and tables can be used to estimate the TDH for lengths and diameters of pipes due to friction losses in the pipes. Turns and valves in the pipe system add “feet” to the TDH as they resist flow also. Finally, the end uses such as nozzles, spray heads, and drip irrigation add their own pressure requirements. Of the parameters to be measured, TDH is one of the most difficult and is often estimated to some degree instead of achieving a precise measurement. Pressure requirements are also often over-estimated and a “just in case” over-design is often used. This can lead to lower pump performance and high costs over time.

Once we have the power needed to pump the water (HPw) at the actual present flow rate, we can measure the actual electrical power (Pe) being used to currently pump the water at the GPM measured. A comparison ratio of actual to theoretical optimum power reflects the pumping system’s actual efficiency via the following relationship:

\[
\text{Eff}_{\text{TOTAL}} = \frac{HPw \times 0.746}{KW_{\text{MEASURED}}}
\]

Notice that the measured power will always be greater than the theoretical power and that the kW measured term is placed in the ratio the dividing part of the equation. We will end up with an efficiency number between 0 and 1. In reality we will never get close to even 80% because of the pump and motor’s efficiencies in the kW measured. Typically, the pumping system’s total

\(^2\) In water systems, “feet” of pressure correspond directly to psi pressure. It is an old measurement system still in wide use.
efficiency will be between 0.4 and 0.7 (40 and 70%). The system efficiency will also tend to be better as the pumping system gets larger. This is because large electric motors and pumps are generally more efficient than smaller motors and pumps. The table below (Table 1.) shows a range of pump system efficiencies for different motor horsepower’s. Notice the general increase in efficiency as equipment gets bigger. This does not imply that we should purposely oversize equipment however.

<table>
<thead>
<tr>
<th>Motor HP</th>
<th>Low</th>
<th>Fair</th>
<th>Good</th>
<th>Excellent</th>
</tr>
</thead>
<tbody>
<tr>
<td>3-7.5</td>
<td>&lt;44.0</td>
<td>44-49.9</td>
<td>50-54.9</td>
<td>&gt;54.9</td>
</tr>
<tr>
<td>10</td>
<td>&lt;46.0</td>
<td>46-52.9</td>
<td>53-57.9</td>
<td>&gt;57.9</td>
</tr>
<tr>
<td>15</td>
<td>&lt;47.1</td>
<td>48-53.9</td>
<td>54-59.9</td>
<td>&gt;59.9</td>
</tr>
<tr>
<td>20-25</td>
<td>&lt;48.0</td>
<td>50-56.9</td>
<td>57-60.9</td>
<td>&gt;60.9</td>
</tr>
<tr>
<td>30-50</td>
<td>&lt;52.1</td>
<td>52.1-58.9</td>
<td>59-61.9</td>
<td>&gt;61.9</td>
</tr>
<tr>
<td>60-75</td>
<td>&lt;56.0</td>
<td>56-60.9</td>
<td>61-65.9</td>
<td>&gt;65.9</td>
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<tr>
<td>100</td>
<td>&lt;57.3</td>
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<td>150</td>
<td>&lt;58.1</td>
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<td>&gt;68.9</td>
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<td>63.9-69.4</td>
<td>&gt;69.4</td>
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<tr>
<td>250</td>
<td>&lt;59.1</td>
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<td>63.9-69.4</td>
<td>&gt;69.4</td>
</tr>
<tr>
<td>300</td>
<td>&lt;60.0</td>
<td>60-64.0</td>
<td>64.1-69.9</td>
<td>&gt;69.9</td>
</tr>
</tbody>
</table>

Table 1. Typical pump system efficiencies (PG&E)

To see what the energy cost implications of this are, the following calculations for one 30 HP pump will help illustrate the costs involved. The efficiency of the example pump in question’s is determined to be 45% using the techniques above. This could be an old pump that is seriously clogged with sediment and has wear on the impeller. This low efficiency example is not uncommon. What if we could rework the system to be 61% efficient?

Pump System Improvement

Current pump system calculated at 45% pumping efficiency – Improved to 61% efficiency, pump is running 85% of the time.

Power Savings (one 30 HP pump):

---

3 Electrical costs at $9/kW-month and $0.06/kWh
\[ P_{\text{savings}} = \frac{[\text{HP} \times 0.746 \times \%\text{Load}^4]}{\text{System Effic. old}} - \frac{[\text{HP} \times 0.746 \times \%\text{Load}]}{\text{System Effic. old}} \]

\[ P_{\text{savings}} = \frac{[30 \times 0.746 \times 1.0]}{0.45} - \frac{[30 \times 0.746 \times 1.0]}{0.61} \]

\[ P_{\text{savings}} = 49.7 \text{ kW} - 36.7 \text{ kW} = 13 \text{ kW} \]

Energy Savings = Power Savings \times \text{Run Time}

\[ E_{\text{savings}} = 13 \text{ kW} \times (8,760 \text{ hours/year}) \times 0.85 \text{ (load factor)} \]

\[ E_{\text{savings}} = 96,798 \text{ kWh/year} \]

Cost Savings:

\[ C_{\text{savings}} = (P_{\text{savings}} \times \text{Power Cost}) + (E_{\text{savings}} \times \text{Energy Cost}) \]

\[ C_{\text{savings}} = (13 \text{ kW} \times $9/\text{kW-mo} \times 12 \text{ months}) + (96,798 \text{ kWh/year} \times $0.06/\text{kWh}) \]

\[ C_{\text{savings}} = $1,404 + $5,808 = $7,212/\text{year} \]

As can be seen, this is not a small amount of savings! Multiply this by several pumping systems with similar efficiencies over several years and you get tens of thousands of dollars of opportunity costs. Achieving a 61\% pumping efficiency might require extensive rework of the current system but the cost savings over time can be attractive.

**Difficulties**

Acquiring the data needed for the pump efficiency calculations can sometimes prove difficult. The depth of the well is needed as well as an accurate estimate of the system distribution head pressure. Well openings are sometimes not accessible at all and the water level is often guessed at. The flow rate of the pump system can sometimes be difficult to measure for a variety of reasons. If air or solids are in the water flow, faulty velocity measurements can result. Possibly the biggest problem for average cost calculations is that most systems do not operate at one constant load. Determining the average or actual load may require data-logging or (again) estimating. Without actual system data, average loads over long time periods are often over estimated.

**Summary**

While you may not have the equipment or means to perform the pump tests, if your operation has several large pumps running for long periods of time, it may be worth the expense to have these systems tested by a professional. Companies that often have this service include:

---

\(^4\) Load factor described by customer
irrigation, well drilling and pump supply companies. If the efficiencies are reported to be low, the companies may also be able to help you service or redesign the systems. You might test a sample of pumps and determine if further testing is justified. It is also doubtful that electrical utility costs will decrease in the future. Remember, if pump system run times are long – the payback time may be short and very attractive for addressing the problems.

References:

- Centrifugal Tests (ANSI/HI 1.6 -2000), Hydraulic Institute, 2000