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## Strategies for Reducing Oil Field Electric Power Costs in a Deregulated Market

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### Abstract

The cost of electricity is one of the single largest items associated with oil and gas production. This cost however tends to be overlooked relative to other production costs, due to the regulated nature of the utilities combined with its specialized and non-core technical requirements. In spite of this, several studies and strategies over the years have looked at ways of reducing this cost component with meaningful results. Many of these strategies consist of structuring loads and designing equipment to take advantage of the utilities regulated rate structure. As the electricity industry in the US moves towards deregulation, these rate structures will no longer exist and in their place will be contracts negotiated on a free market basis between the user and supplier(s) of electricity.

In the upcoming deregulated electricity market, three key strategies are available to effectively manage oilfield power costs; 1) real time monitoring and *control* of the electrical load 2) in-field generation of electricity and 3) negotiation of an integrated power supply agreement. Because electricity is the ultimate just-in-time product, prices vary greatly depending upon when the power is consumed. The strategies listed above allow for the user to proactively structure their power supply systems to address the fundamental volatility of the real price of electricity. The effect is to strip out the historic premium that is paid to the utility to handle the natural volatility of electricity prices by blending load shifting, internal generation and market purchases.

This paper examines different scenarios where the above strategies are proposed and makes estimates for potential cost savings. These solutions utilize existing technology applied to the changing market environment and therefore focus on economic justification as opposed to technology verification.

In one such case the pumping intervals for a collection of wells is adjusted using real time power prices combined with remote operations. This has the effect of reducing the total cost of the electricity consumed per barrel of production while only marginally reducing the actual number of barrels produced.

### Introduction

The cost of electricity has historically been one of the largest operating costs in the production of oil and gas. Additionally this cost tends to increase over time as the typical oil field ages. Artificial lift, gas compression, water treating, water injection and so forth are installed as the fields' age and all of these functions consume an ever-increasing amount of electricity. This increasing electric load trends in the opposite direction from the net oil recovered.<sup>1</sup> The result is that electricity costs tend to make up a larger and larger percentage of the field's lifting costs. It is not uncommon to see power costs representing up to 40-50% of total production costs.

Although power costs are a major cost component of field profitability, they tend to be overlooked relative to other production costs. The reasons are twofold: 1) The technical skills needed are specialized and non-core to the production company and 2) Unlike other suppliers, the utility that provides the electricity is a regulated monopoly. The skills necessary to optimize power costs in this kind of environment are not the same as optimizing the other more conventional costs such as well servicing, treating chemicals, artificial lift... As a direct consequence of this, most oil operators do not manage their power costs. Most operating companies endure their power costs without taking proactive measures to change undesirable situations.<sup>1</sup>

In spite of this, several studies have looked at ways of reducing the cost of power with meaningful results. The recommendations from these studies can be divided into three groups: 1) optimizing the mechanical systems<sup>2,3</sup>, 2) optimizing the electrical systems<sup>3,4,5</sup> and 3) working with the utility to optimize usage against a regulated rate structure.<sup>3,4,5,6</sup> Examples of item 1 include, balancing pump units, installing pump off controllers, modifying pumping unit stroke length and speed. Examples of item 2 include correctly sizing electric motors, correcting power factor penalties and resultant line losses with capacitor banks, meter consolidation, distribution system optimization and retrofit, and the use of high voltage substations. Examples of item 3 include moving

to interruptible or curtailable rate structures, bill verification, demand management and regulatory intervention. All of the approaches mentioned in items 1 and 2 should be thoroughly researched and implemented as the start for any electricity cost reduction initiative.

The approaches examined in item 3, however deal with working within a defined and rigid rate and business structure. Operators were encouraged to examine how they were being charged for electricity and change their behavior to optimize their position within these relatively rigid price and rate structures. With the advent of deregulation, this area will change radically. Operators must understand how deregulation works in their area and how to best position their company to take advantage of these changes.

**Deregulation.** Electric power generation in the United States is changing from a regulated industry to a competitive industry.<sup>7</sup> Where power generation was once dominated by vertically integrated, investor-owned utilities (IOUs) that owned most of the generation capacity, transmission, and distribution facilities, the electric power industry now has many new companies that produce and market wholesale and retail electric power. These new companies are in direct competition with the traditional electric utilities. Today, vertically integrated IOUs still produce most of the country's electrical power, but that is changing.

The long-standing traditional structure of the industry was based, in part, on the economic theory that electric power production and delivery were natural monopolies, and that large centralized power plants were the most efficient and inexpensive means for producing electric power and delivering it to customers. Large power generating plants, integrated with transmission and distribution systems, achieved economies of scale and consequently lower operating costs than relatively smaller plants could realize. Because of the monopoly structure, Federal and State government regulations were developed to control operating procedures, prices, and entry to the industry in order to protect consumers from potential monopolistic abuses.

Several factors have caused this structure to shift to a more competitive marketplace. First, technological advances have altered the economics of power production. For example, new gas-fired combined cycle power plants are more efficient and less costly than older coal-fired power plants. Also, technological advances in electricity transmission equipment have made possible the economic transmission of power over long distances so that customers can now be more selective in choosing an electricity supplier. Second, between 1975 and 1985, residential electricity prices and industrial electricity prices rose 13 percent and 28 percent in real terms, respectively. These rate increases, caused primarily by increases in utility construction and fuel costs, caused Government officials to call into question the existing regulatory environment. Third, the effects of the Public Utilities Regulatory Policies Act of 1978, which encouraged the development of non-utility power producers that used renewable energy to generate power, demonstrated that

traditional vertically integrated electric utilities were not the only source of reliable power.

Competition in wholesale power sales received a boost from the Energy Policy Act of 1992 (EPACT), which expanded the Federal Energy Regulatory Commission's (FERC's) authority to order vertically integrated IOUs to allow non-utility power producers access to the transmission grid to sell power in an open market. This capability was further strengthened with a series of FERC orders that helped define transmission tariffs and procedures as well as create regional transmission organizations (RTOs) that will control and operate the transmission grid free of any discriminatory practices.

In addition to wholesale competition, retail competition has started in many States. How, and if, a particular market is deregulated is primarily defined at the State level. For the first time in the history of the industry, retail customers in some States have been given a choice of electricity suppliers. As of July 1, 2000, 24 States and the District of Columbia had passed laws or regulatory orders to implement retail competition, and more are expected to follow (**Table 1**). The introduction of wholesale and retail competition to the electric power industry has produced and will continue to produce significant changes to the industry.

However, the introduction of these new markets has been far from seamless. California, where retail competition was introduced in 1998, has had severe problems recently. Electricity prices in some parts of the State have tripled and there have been supply problems as well. Although not as severe as California, New York's electricity market has had price spikes, which may be attributable to problems in the market design. While some observers argue that deregulation should be scrapped, others argue that deregulation is a noble endeavor and that these problems can be solved with structural adjustments to the markets.<sup>5</sup>

It is generally believed that the deregulation of the electricity industry will continue but at different rates depending upon the individual State. The recent events in California, however may cause some states to slow down their deregulation plans until solutions to the California problem can be assessed. As of the writing date of this paper, most States that have comprehensive deregulation legislation enacted are moving forward with their plans.

**Price Volatility.** In order to fully appreciate the impact of deregulation a discussion of the economics of power generation is in order. Electricity is the ultimate just-in-time product.<sup>8</sup> It is also unique in that it is one of the few "commodities" that cannot be stored or held in inventory. Therefore every kilowatt of electricity that is consumed must be generated at that instant. This causes significant price volatility because generating capacity must be always available even though it may be utilized for only a small fraction of the time.

The real cost of electricity is governed by the principle of economic dispatch. Electricity costs are a combination of production costs (fuel, operations, maintenance, taxes...) and

capital costs (or first cost) spread over the life of the plant. Once a power plant is built the capital cost is fixed and from an economic standpoint is a “sunk” cost. The production cost is a variable cost and is only incurred when the plant is running. The production and capital costs associated with producing electricity differ depending upon the type of generation. Plants with low production costs are dispatched first (these tend to be the plants with high first costs such as hydro, nuclear or coal). As the demand for electricity increases, the higher production cost plants are turned on in the inverse order of their production costs (typically steam plants then combined cycle gas plants then simple cycle peaking plants). This has the impact of increasing the cost of electricity as demand increases because more and more of the consumed power is produced in the higher cost plants.

The demand for electricity rises and falls depending upon the time of day and time of year. In general, more electricity is used during the day and during the summer, (**Figs. 1 and 2**). There are, however areas of the country that peak during the winter months or do not have much variation in usage between the seasons of the year. As we have seen above the cost of electricity rises with rising demand. We should therefore expect the price of electricity to be the highest during peak periods and lowest during off-peak periods. In fact this is exactly what happens as can be seen in the wholesale power market.

The wholesale power market has been in existence for the last several years and has sufficient liquidity to be a good proxy for the “real” cost of electricity. These markets trade power for delivery over a variety of time periods and allow us to examine the volatility of prices over time. Although these transactions are between wholesale suppliers and buyers, the underlying volatility is passed on to the retail customer in some manner. This historically has been absorbed by the regulated utility with end user rates that were fixed high enough to cover underlying cost fluctuations.

Wholesale power is traded in Megawatt-hour increments (1000 Kw-hrs) with the most common delivery being next day peak (16 hours) or next day off-peak (8 hours). As an example of the volatility of wholesale prices, the peak and off-peak price of power is listed in **Table 2** for different times of the year in the Texas market (ERCOT).

It can be seen from this data that the price of power fluctuates significantly over the day as well as throughout the year. On a Kw-hr basis this would be the equivalent of electricity costs moving between 1.5 cents/kw-hr to over 30 cents /Kw-hr depending upon when that Kw-hr is used. From this analysis it can be seen that the cost of electricity is not only impacted by how many kilowatts are required but when they are required.

**Impacts of Deregulation.** As the electricity industry deregulates, customers will be presented with a new set of options as it relates to the supply of their electricity. The fundamental structure of the industry has been based on the vertical integration of utilities, i.e., their involvement in the three functions of power supply. Those functions are

generation, transmission, and distribution of electricity. Generation is defined as the production of electric energy from other energy sources. Transmission is the delivery of bulk volumes of electric energy over high-voltage lines from the power plants to the distribution areas. Distribution includes the local system of lower voltage lines, substations, transformers and meters, which are used to deliver the electricity to end-use consumers.

How, and if, a particular market is deregulated is primarily defined at the State level. Most of the plans being implemented or considered revolve around breaking up the vertically integrated utilities and allowing for generation to be unregulated and subject to competition while transmission and distribution continue being regulated. A wide range of activities have been designed to promote industry competition at the retail level and to complement the wholesale market and stranded cost initiatives of the Federal Energy Regulatory Commission (FERC).

As a representative example of a deregulation plan we will examine the Texas program. Effective January 1, 2002 Texas will implement electric industry deregulation.<sup>10</sup> The services that are currently being provided by the regulated utilities will be offered by three separate types of companies. Power will be produced by generators who will be non-regulated and competitive. Power will be moved by transmission and distribution companies (T&D) who will continue to be regulated. Finally, the marketing and customer service function will be offered by a third type of company called a Retail Electric Provider (REP).

End users will purchase electricity from REP's, which will be delivered by the regulated T&D company. The REP aggregates users requirements and in turn purchases their power requirements on a free market basis from the generators. The form and price of the purchased electricity will be negotiated on a free market basis between the end user and any number of REP's who may be interested in that customer's business. In addition to the price of electricity purchased, an additional charge based upon the electricity used, will be collected by the T&D company. This rate or tariff will be set by the Texas Public Utility Commission (PUC) and be based upon the average T&D cost for the state plus a charge for recovering so called stranded costs. These stranded costs are the amount that the book value of the utility's existing power plants are above the fair market value of those plants in today's environment (i.e. nuclear plants). Other changes effective January 1 is that all current tariff's cease. This includes the instantaneous and with-notice interruptible rates used by the majority of oil and gas operators (Rider I in Texas). Furthermore, a “price to beat” will be established by the current utilities for residential and small commercial customers that is 6% less than current rates.

Another impact of deregulation may be the decrease in reliability of grid delivered electricity. In the past, regulators insured that the utilities had sufficient generation for the estimated peak demand plus an additional amount for contingencies. These so-called reserve margins were in the range of 15% or greater and would be available as a form of

insurance in case of unplanned events, (abnormally hot weather, mechanical failures of a generation plant, problems with transmission grid...). With deregulation, the free market will determine the equivalent of the reserve margin through the combined actions of the generators. It is expected that the resultant reserve margin will reduce for both generation and transmission capacity therefore impacting the users when system failures or unexpected load patterns occur. The result may be more power outages and/or voltage drops.

The changes outlined above impacts the dynamics of purchasing electricity. Instead of trying to adjust to a rigid, non-flexible rate structure, the operator can now proactively structure power contracts that more effectively reflect their operations, risk profile, capital flexibility and so forth. In general, deregulation will probably cause some customers to pay less and some more. The market place will set the price.

### Cost Reduction Strategies

The operator of oil and gas properties is presented with the following: 1) Electricity costs are a large percentage of operating costs and will rise as their fields mature, 2) A new industry structure is being introduced with new opportunities and risks, 3) Historical buying habits and supplier relationships are being changed by competitive as well as regulatory forces, 4) Field operations are often located in remote or rural locations and 5) Electrical systems are potentially old and inadequate as they were installed during the early development of their fields.

In this environment it is important for the operator to take a more proactive position in arranging and purchasing electricity. The risk of complacency is higher prices or restricted supply as other more savvy users structure agreements that take advantage of the newly evolving market. Three key strategies are recommended in order to positively position the operator in the deregulated market:

- Real time monitoring and control of electrical loads
- In-field generation of electricity and/or thermal heat
- Negotiation of an integrated power supply agreement

These strategies are not to be taken in place of the more conventional optimization steps referenced in the introduction, but should be undertaken in parallel or after the mechanical and electrical optimization steps have been completed. The discussion that follows is intended to provide options for the operator to further enhance or protect his electricity cost position in a deregulated environment.

**Real time monitoring and control.** As we have seen, the underlying “real” cost of electricity is extremely volatile. The time at which a Kw of electricity is consumed is the single largest determination of its true cost. Historically, however electricity has been priced with a demand charge and an energy charge that was independent of time of use.<sup>4</sup> Peak demand was defined in kilowatts by the amount of electrical generation capacity that the utility had to have available at any

time to satisfy the customer’s maximum load. The energy charge was the actual amount of energy consumed in kilowatt-hours and also not time dependent. The underlying fluctuations of “real” costs were absorbed by the utility. The utility’s rate structure was based upon earning a return on the generation assets required to meet the customer’s maximum usage plus a flow through charge for the actual energy used. This type of contract will almost assuredly be available after deregulation. The operator in essence is paying a third party to absorb the underlying volatility of the real cost of electricity. It is predicted that these types of contracts will be similar to existing agreements and include a demand charge and non-time dependent energy charge.

Another basic type of supply contract will emerge that reflects the underlying time based volatility of electrical costs. In these situations the power supplier will not absorb the full volatility of costs into their rate structure but pass these costs along to the customer. An example at the far end of the spectrum of this type of structure would be an agreement in which the price of electricity is set on an hour ahead basis. This would mean that the customer would pay potentially a different price for electricity for every hour of the day and every day of the year.

In both of these types of purchase agreements, it will be important to be able to monitor the real time use of electricity as well as control the loads to optimize the companies overall profit position. In the first case, it will be important to manage the “demand charge” portion of the bill. These demand charges are often set on the average load over some utility selected interval (normally 15 to 30 minutes). Once established, this highest instantaneous usage sets the demand charge for an entire billing period (most often monthly but can be the preceding 11 months).<sup>4</sup> This has a ratcheting effect in that a peak load that may have occurred for some non-recurring reason sets a demand charge that is paid for over a much longer time period. Obviously monitoring and controlling the load to eliminate excessive peaks will reduce the resultant total electricity cost. Harris and May describe using coordinated digital timers on pumping wells to reduce spikes in the load, therefore reducing the billed demand charge.<sup>11</sup>

In the second type of supply agreement where the price of energy is time-of-use dependent, real time monitoring and control becomes key to the successful operation of the contract. This area is believed to provide the most promise for industrial customers to proactively keep costs down by linking real-time energy usage information with real-time and forward power prices. This will allow customers to modify energy demand through remote control of equipment, subject to predetermined guidelines. In these types of contracts, the customer will be seeing more of the true cost of electricity and not “paying” for a third party to step in and manage the underlying cost volatility. Although this should produce the lowest theoretical power costs, the customer must be able to absorb the underlying price volatility through their financial strength, load shedding or in-field generation. Examples of different scenarios will be explored later on in the paper.

Real time monitoring and control systems can be installed at varying levels of sophistication. To be the most effective they should provide some form of real time communication. This may take the form of a continuous connection or a periodic upload that occurs every few minutes to every few hours. Manual collection of data and control of loads will not be responsive enough to sufficiently optimize power purchases in some of the more aggressive supply agreements (specifically any kind of time-of-use contracts). Both continuous and periodic communication systems are now available that are cost effective and easy to use. Companies are now available that can provide these services on an out-sourced basis and deliver the user interface through a standard Internet connection. An example of these types of system is shown in **Fig. 3**.

The monitoring portion of the system should be more than simple meters and provide some level of intelligent monitoring. This would include user defined informational breakdowns and groupings, trending data, intelligent alarming and ongoing calibration capabilities. The design of the system should allow for the gathering and analysis of the specific type of load data necessary to optimize the company's profit position relative to the power supply agreement.

Once data is received through the monitoring system, the planned reactions of the system need to be established. These reactions must be designed to integrate with the electricity supply agreement and may be based upon:

- Shutting down or time shifting loads based upon the current or forward price of electricity
- Shutting down or time shifting loads based upon maximizing profit of a defined business unit or sub-unit (a well)
- Load leveling or peak shaving

Furthermore it must be established how many, if any, of the control decisions will be automatic and carried out by the system and how many will be manual and require input by the operator. This process can be established by starting with all decisions requiring operator input and moving to some automated decision making once all parties become comfortable with the internal logic of the system.

**In-Field Generation.** The generation of power in the field has always been a viable option to reduce electricity costs. This is especially true in a cogeneration installation.<sup>5</sup> Cogeneration is the simultaneous production of electricity and heat from a single fuel source. The generation of power near a load with or without use of the exhaust heat is today often referred to as distributed generation (DG) or distributed resources (DR). With the advent of deregulation the ability to use distributed generation to reduce costs is significantly increased.

The existing status of DG or cogeneration was defined in the late 1970's as the result of two separate legislative acts: The Public Utility Regulatory Policy Act of 1978 (PURPA)

and the Natural Gas Policy Act. This legislation required that the public utility must purchase any electricity produced by a qualified facility. This allowed oil and gas operators to use natural gas to produce electricity with in-field generators and use the exhaust heat for some kind of processing requirement (such as at a gas plant or a tank battery). The utility was required to purchase any excess electricity but the offered price was often times not sufficient to justify the incremental capital costs. Producing companies, however, could make the economics work if the electricity generated displaced power that would have to be purchased from the utility for the companies electrical requirements. Several DG projects have been installed since that time with the vast majority being cogeneration projects as opposed to power-only generation projects.

To understand the possibilities for distributed generation, a quick discussion of DG economics is in order. DG projects normally utilize small generation equipment to produce electricity close to an electrical load. The equipment can be engine or turbine driven, fueled by natural gas and normally under 10 Mw's in size. The cost of generating electricity in a DG project is the combination of capital costs, operations and maintenance cost and fuel cost. The cost of the owning and operating the generator is in the range of 2 to 3 cents per Kw-hr and varies with load factor, location, size, cost of capital, life of project and other project specific items. This includes capital recovery at a cost of capital hurdle rate and can either be purchased by the operator or outsourced depending upon operating preferences. The cost of the fuel component can be estimated by multiplying the net heat rate of the generator set in BTU's/Kw-hr by the cost of gas. The heat rate of DG equipment is in the range of 10,000 to 14,000 BTU/Kw-hr with units in the 500 Kw to 1500 Kw range being around 11,000. The cost of gas should be the net amount the operator receives for their gas if they are producing and selling gas and should be the acquisition cost of gas if they are not.

A rough estimate of the cost to generate electricity using distributed generation is listed in **Table 3**. These numbers are for generating electricity only and do not reflect using any of the exhaust heat for in-field processes. If the exhaust heat is utilized in some manner then the net heat rate attributable to power generation is greatly reduced. Depending upon the amount of the thermal heat used, total efficiencies can be raised from 35% for generation only, up to as high as 80-90%. This would have the impact of reducing the fuel cost portion of the total costs listed above by greater than 50%.

From the above analysis it is obvious that if the operator can generate electricity for less than he is purchasing from the grid, DG can make economic sense. If this kind of preliminary evaluation looks promising, a more detailed assessment involving backup agreements, environmental siting, legal and regulatory issues will need to be investigated. The economics and business structure of generating your own power is essentially the same before and after deregulation. The exception, however is that interconnect procedures have been developed and implemented by the various States in order to encourage these types of projects. This should make

it significantly easier to interface with the utility and install the DG project.

The major impact of deregulation on justifying potential DG projects comes when the operator wishes to generate more power than he consumes at site. In the past the utility had an obligation to purchase excess electricity from these qualified facilities, however the price that they were required to pay was often not acceptable. With deregulation many more options and potential customers are available to the DG owner to sell his excess power. Not only does this change increase the number of companies who may be interested in bidding on the power, but allows for a variety of different contract structures.

- Enter into a firm purchase price agreement (PPA) to sell the entire output of the plant
- Sell power into the wholesale market on a merchant basis (normally peaking power)
- Generate power in one location where gas reserves are located and consume the power in another (where both sites are owned by the same company)

Selling excess power can significantly improve the economics of DG projects, however it is more complicated to setup and operate. In fact many of the rules and regulations surrounding this function are only now being written. It does appear, however that the States are very much encouraging these types of capabilities and will provide the legal and regulatory structure to accommodate them.

One potential opportunity is using DG as another method to monetize stranded gas reserves. In certain situations an operator may have so called distressed gas in the ground. This would be gas that has reduced value because of some kind of physical constraint that cannot be economically solved using conventional methods. Examples would include gas reserves that are too far away from an existing pipeline, low volume or low deliverability gas, gas with high impurities, or gas requiring a lot of compression. In these cases conventional solutions, i.e. running a gathering system pipeline to the well, may not be economic because the capital costs required for a conventional solution cannot be recovered over the expected volumes available.

In these situations a possible option is to burn the gas in a generator located at the source and consume on site or sell onto the grid. Distributed generation equipment can burn a wide range of gas types and pressures without additional treating equipment. (For example engine generators can burn gas with greater than 40% nitrogen content or an input pressure less than 1 psi) In addition, electric lines may be readily accessible and the cost to tie the generator into the grid relatively small. Electricity in these situations can be generated at a rate of 2-3 cents/kw (the cost of conversion discussed above) and sold into the wholesale market. Any amount received for the electricity over the 2-3 cents would in essence result in monetizing a gas flow that before was worthless.

**Power Supply Agreement.** As discussed above, deregulation ends the relationship between the operator and his current electricity supplier. In its place will be a supply contract with one of several suppliers that is established in a free market setting. These supply contracts may be standard offerings by a supplier or individually negotiated and structured to meet the technical and economic requirements of both parties. The key, as in any major purchase, is to thoroughly understand your requirements, research the potential solutions, and proactively work with the available suppliers to structure a responsive contract. The steps that need to be taken are as follows:<sup>8</sup>

- Understand your electric load profile
- Investigate changing the shape of your load profile
- Understand your risk profile
- Identify important non-price issues
- Integrate the power supply agreement with your total field power strategy

The first step in this process is to understand current operations. The operator's electric usage profile should be documented by reviewing the last 12 months of monthly invoices. As discussed above, the shape of this load profile is very important in establishing the true cost of electricity. A low load factor (average demand to highest demand) or spiky demand pattern indicates an unattractive load and will be priced accordingly by suppliers. In these situations, strategies that improve the load profile should be investigated before sourcing the supply contract. As mentioned above, real time monitoring and control systems can be used to shape the profile to produce a more attractive load. This will result in a significantly lower supply contract than the unadjusted load. Another potentially simpler solution is to assess the benefits of aggregation.<sup>11</sup>

Aggregation is combining a series of loads to achieve a more attractive load profile. The combination of individual loads increases the load factor because the randomness of field operations tends to average out the peaks and valleys. Aggregation may be as simple as combining several of the company's loads into one purchase agreement. Another form of aggregation is to combine the operator's load with other company's loads with the result being a more attractive load profile as well as increased buying power. Unlike in the regulated market, the physical meters no longer need to be combined as the various loads can be combined on paper and presented to a supplier for pricing. In Texas a special class of entity, called an Aggregator, has been created by the PUC that acts on behalf of several customers to do this very thing.

As we have seen, real electricity prices are incredibly volatile. This underlying volatility has in the past been managed by the utility and, for a price, can be managed by a supplier in the deregulated market. With deregulation, however, the operator will have a variety of different supply options available to him that carry different amounts of risk. The "right" supply contract may be different depending upon how much risk the operator is willing to absorb. For example,

a contract where the price of electricity changes every hour, may produce lower costs but be unworkable to the operator because of budgeting or forecasting reasons. Knowing what the cost of electricity is going to be every month may be worth a premium over the lowest cost but most uncertain option. Another example would be the operator's tolerance for short-term curtailments or even full interruptions of energy delivery. Although these types of contracts can produce lower electricity costs, the cost of shutdown may not warrant the potential savings. One possible way to mitigate this shutdown risk is to intelligently shut down loads (wells) depending upon a prearranged set of criteria designed into the monitoring and control system.

In establishing a power supply agreement the operator must identify and weigh non-price issues. These issues can be difficult to economically evaluate but should be addressed during the evaluation stage. A partial list of some of these items include:<sup>9</sup>

- How many bills do you want to receive each year
- Power quality and energy audit assistance
- Energy monitoring and reporting assistance
- Levels and types of customer service
- Efficiency improvement assistance
- Equipment financing and/or outsourcing
- Financial strength and experience of supplier

Finally any power supply agreement must be integrated into the overall energy strategy that has been developed. With the advent of deregulation the variations of supply agreements should be limitless and suppliers will be available to structure agreements that take into account any field strategies being implemented. For example, a field monitoring and control system must be able to take advantage of low power prices during off-peak, off season times and adjust the load during peak, on-season times. Without the supply contract structured to price power to the operator accordingly, then the control of the load to minimize high priced power will obviously accrue to the supplier and not the operator.

The purchase of electricity will no longer be a given and the operator should take steps to address the new deregulated environment. One way to focus on this issue if not already in place is to dedicate a person to managing the company's energy usage. Third party or outside consultants can be used to evaluate, recommend and even negotiate agreements, however integrating the supply agreement into field based strategies require a thorough understanding of oil and gas operations and the operator should take a hands on role in the process.

### Examples

Three examples are presented that outline the general concepts outlined in the paper.

**Example 1 Demand Management.** Pellegrino and Scott describe an excellent example of managing demand in a large

gas compression facility using a computer-based system to control six-eight thousand horsepower electric motors. The control system monitors the electric demands for the entire facility to ensure the actual demand does not exceed a pre-set maximum level. The system constantly monitors the total electrical load, the load of the various large motors and the total gas throughput in the plant. The system controls the start and stop of the motors as well as a compressor valve unloading system, which reduces compressor horsepower and its resultant electrical demand. As gas deliveries increase, the computer controls the valve unloading system and other smaller electric loads to maintain electric load below the desired peak.

This is a good example of an automation system increasing the load factor and minimizing demand spikes with little or no operational impact. The facility performed its primary function (moving gas) with no change of performance so the significant savings generated by the improved load factor need only to offset the cost of the automation system which using today's automation capabilities are quite reasonable.

**Example 2 Distributed Generation.** An operator has an oil field that has a billed electric load that is inconsistent and varies between 500 Kw and 1500 Kw. Its load factor is 50% with a total energy usage of 6.5 million Kw-hrs per year. The wells are on beam pumps with pump off controllers installed at each well. As the wells start and stop based upon their individual parameters the loads can sometime spike as several wells randomly start at the same time. The field has developed over time and currently has several different meters that are invoiced separately each month. No processes are performed in the field that utilize heat so cogeneration is not an option. The field has associated gas that is sold for \$3.00/mmBtu or a 33% discount to a local delivery point due to high nitrogen content. The operator is currently paying 8.8 cents per kw-hour in total electricity costs.

A real time monitoring and control system is installed that can coordinate the pump cycles of the oil wells so that a majority of wells do not start up at once and at any particular time the calculated average number of wells are pumping. The control system in conjunction with the consolidation of distribution system is predicted to bring the load factor up from 50% to 85%. This would reduce the maximum required demand from 1500 Kw to 875 Kw of generation. (6.5 million Kw-hrs/year / 8760 hours/year / 0.85 load factor). After analyzing the electrical load and distribution system the operator installs (3) 300 Kw engine generators at two separate locations and upgrades the distribution system to accommodate this new generation source. (For this example, the starting loads of the electric motors will not be analyzed in order to simplify the economics) The units are placed in two separate locations instead of one central location to reduce the cost of retrofitting the distribution system. The operator uses the gas produced in field as the fuel source for the generators therefore producing electricity at a rate of 5.8 cents per Kw-hr. (2.5 cents conversion cost plus 11,000 Btu/Kw-hr \* \$3.00/mmBtu ).

The real time monitoring and control system is outsourced on a monthly service charge basis and costs the operator 0.8 cents per Kw-hr. The savings impact of this program would be 8.8 cents- 5.8 cents - 0.8 cents or 2.2 cents per Kw-hr, a 25% reduction. For this example the yearly savings would equal \$142,000 (6.5 million \* \$.022) after accounting for all of the capital costs required to implement the project.

**Example 3 – Load shaping.** In this example we will assume that the operator does not have access to gas at a cost effective rate and must purchase all of their requirements from a retail electric supplier. In this field the operator has a 1500 Kw load that is reasonably well balanced with a load factor of 80%. Electricity is currently purchased at a total cost of 5.8 cents/Kw-hr from two well placed meters. No meter consolidation options are viable. The field is a mature oil field and has a combination of marginal and good producers. Water cuts in the field are in the 90-97% range and all wells are on beam pumps with pump-off controllers. The operator has several wells that have reached their economic life and must be shut in if cost reductions cannot be found. Electricity costs on these marginal wells is 45% of total lifting costs.

A real time monitoring and control system is installed in the field that can determine the pump off condition of the wells, control the wells shut down cycles as well as shut down and start up wells if required. The system monitors the load vs. position curve on every stroke of the pump unit and uses the information to recommend optimization procedures, (rebalance units, mechanical failure prediction, pump leaks...) In addition the system can derive a fluid buildup curve for each well based upon an automated routine where shut-in times are incremented and fluid levels measured using the load-position data from the pumping cycle. This information can be used to predict lost production upon scheduled or unscheduled shutdowns.

A power supply contract is negotiated where the operator purchases power at the wholesale clearing price for hour-ahead electricity plus 15\$/Mw-hr (T&D plus marketing basis). The control system receives a real time feed from the supplier of what the price of electricity will be for each hour of the day, updated on a continuous basis. For each well the system compares the price of electricity to an entered or calculated set point and if the upcoming price exceeds the set point the well is shut in. The system repeats this process every hour.

If required the system can optimize the pump cycles based upon the upcoming price of electricity and their impact on financial returns. The system begins by looking at the actual pumping intervals for the last unadjusted 24 hour time period. Using this as a base case, the system searches for a higher return scenario for the next 24 hours using the upcoming hourly electricity prices compared against the base case pricing and how any changes will impact fluid production. The impact on production is estimated from the fluid buildup information that has been developed by the system for each well. Since a barrel of oil not produced today is not lost forever but postponed until depletion, the economic impact of any lost production is estimated by comparing the field profit

of the produced oil today (using the actual electricity price) with the field profit of the produced oil at depletion (using a modeled electricity price). Because this deferred production is not realized until the future, the present value must be calculated at a user-defined discount rate. If the financial return of deferring production because of shifted pumping cycles is greater than the base case scenario, then the proposed cycle is implemented for the next 24 hours. This process is repeated for every change in the price curve.

The system outlined above provides the operator with theoretically the lowest electricity costs because there is no markups or fees being charged to reduce volatility. The operator is taking on the full risk of market prices but can mitigate these risks by shutting in wells when the price of electricity is excessive. These high prices are usually short lived and therefore any shut-in production may be relatively small. This scenario may be attractive for fields with large amounts of marginal wells because they can be pumped only when the price of electricity drops to some attractive level. This would have the impact of significantly lowering the lifting costs for the well at the times when electricity is cheap and shutting in the well when power costs are high. The economic impact of the postponed production is minimal in these cases because at the higher electricity prices the wells are not economic so the incremental value of production is zero.

### Conclusion

As the electricity industry undergoes deregulation oil and gas operators will need to proactively structure and manage their energy costs. Where before there was a single supplier with rigid business practices and regulated rate structures the operator will find a many suppliers with a variety of supply options.

To manage electricity costs the operator must first optimize all mechanical and electrical systems. These areas have been thoroughly discussed in other papers but if not properly executed still provide the largest potential for electrical savings. Once these areas have been addressed, three key additional strategies can be utilized to effectively manage power costs:

- 1) Real time monitoring and control systems can analyze and adjust electrical load to reduce total energy costs based upon when and at what price electricity is used.
- 2) Distributed generation can be used to economically produce consumed power and exhaust heat for in-field processes (cogeneration). The economics of DG can be further enhanced by selling excess power generated into the wholesale market.
- 3) A power supply agreement can be proactively negotiated that integrates with the energy management system and takes into account the operator's risk profile, financial resources and level of in-house expertise.

These strategies are especially important as the electricity industry deregulates and new supply options and suppliers replace existing regulated structures. Deregulation will have a major impact on oil and gas operators because energy is such a large percentage of operating costs and field operations offer flexible opportunities to structure innovative energy management solutions.

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Table 1 – Status of Deregulation by State

States With Firm Deregulation Schedule							Other States	Status
State	Implementation Date						Other States	Status
	97	98	99	00	01	02		
Rhode Island	X						Investigative Stage: Commission or Legislative Investigation Ongoing	
California		X						
Massachusetts		X						
Delaware			X					
Illinois			X					
Montana			X					
New Jersey			X					
Pennsylvania			X					
Arizona				X				
Connecticut				X				
District of Columbia				X				
Maine				X				
Maryland				X				
New Hampshire				X				
Michigan					X			
Nevada					X			
New Mexico					X			
Ohio					X			
Virginia					X			
West Virginia					X			
Arkansas						X	No Activity	
Oklahoma						X		
Oregon						X		
Texas						X		
New York								Legislation/ Orders Pending
Alaska								
South Carolina								
Alabama								
Colorado								
Florida								
Indiana								
Iowa								
Kentucky								
Louisiana								
Minnesota								
Mississippi								
Missouri								
North Carolina								
North Dakota								
Utah								
Vermont								
Washington								
Wisconsin								
Wyoming								
Georgia								
Hawaii								
Idaho								
Kansas								
Nebraska								
South Dakota								
Tennessee								

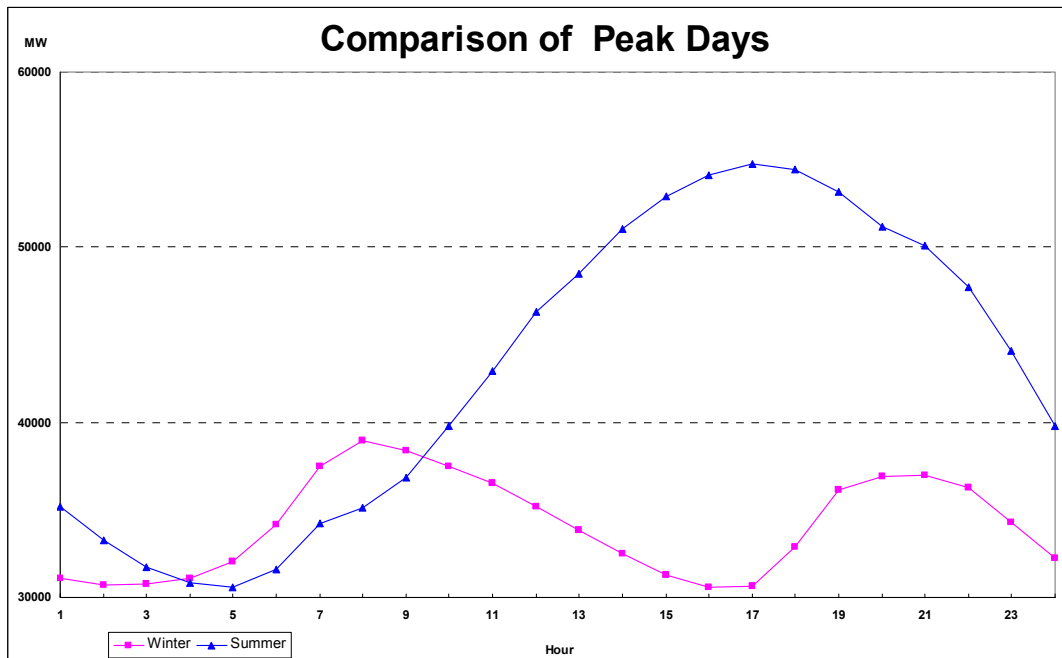
Table 2 – Wholesale prices in the Texas Market (ERCOT)

(\$/Mw-hr)	Winter <u>Average</u>	Summer <u>Average</u>	High <u>7/17/00</u>	Low <u>1/12/00</u>
Peak	\$ 24.56	\$ 53.00	\$ 300.00	\$ 21.50
Off-peak	\$ 15.00	\$ 18.50	\$ 19.50	\$ 15.00
Ratio Peak/Offpeak	1.6	2.9	15.4	1.4

**Table 3 – Cost of Electricity for Distributed Generation at Different Gas Prices**

(in cents/Kw-hr)	<u>Cost of Conversion</u> <sup>(a)</sup>	<u>Fuel Cost</u>	<u>Total Cost</u>
Flared Gas	2.5	0 <sup>(b)</sup>	2.5
\$2.00/mmBtu	2.5	2.2	4.7
\$3.00/mmBtu	2.5	3.3	5.8
\$4.0/mmBtu	2.5	4.4	6.9
\$5.0/mmBtu	2.5	5.5	8.0

(a) Includes recovery of capital costs, operations and maintenance  
 (b) Excludes royalties



**Figure 1 – Usage of electricity in ERCOT for the peak days in summer and winter. The use of electricity, on average, can vary by close to 100% for the summer months but is in a smaller band during winter months.**

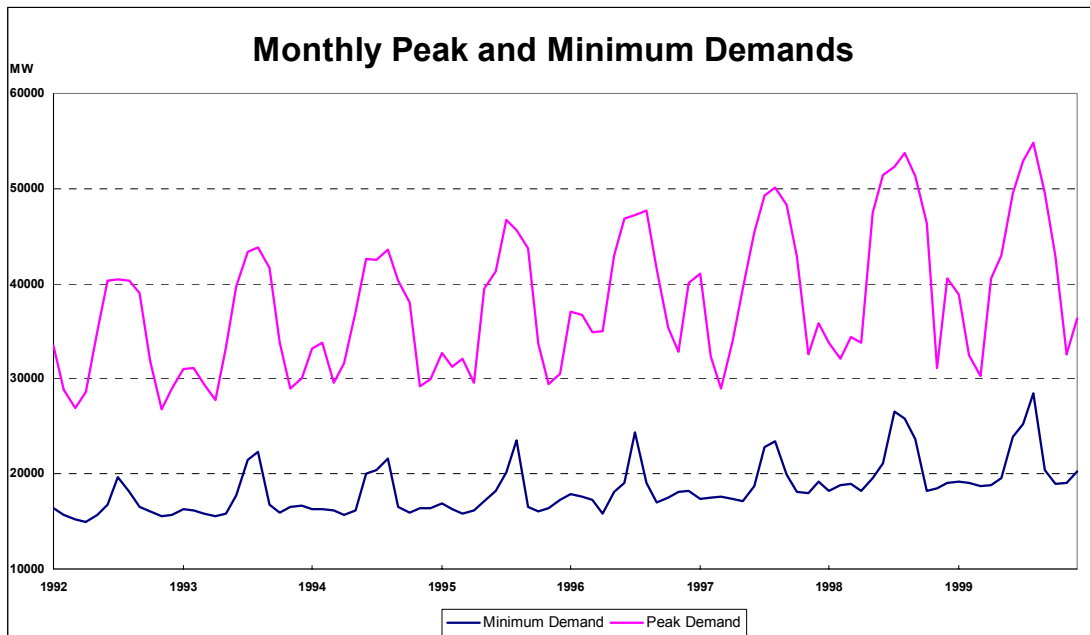


Figure 2 – This chart shows the variation in usage by month for the ERCOT region. It can be seen that usage varies significantly depending upon the time of year but follows a seasonally predictable pattern.

## Sample Real-Time System

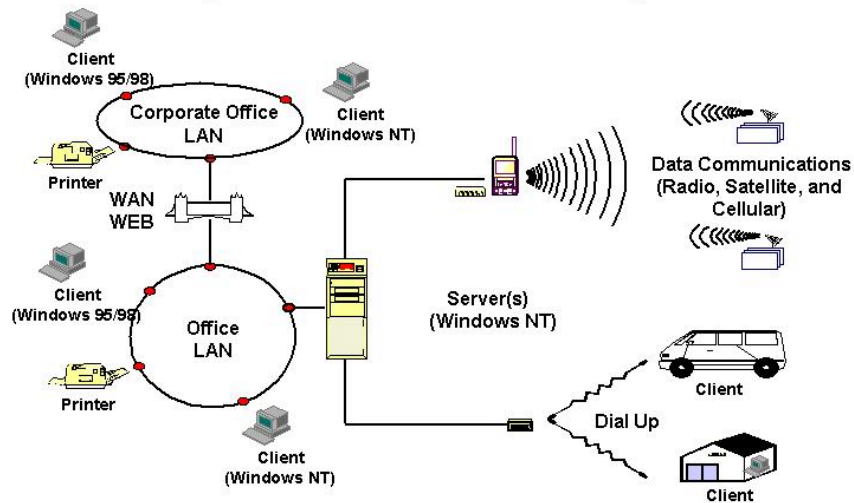


Figure 3 – An example of a real time monitoring and control system which uses one of three different forms of communications media, radio, satellite or cellular.