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OFFGASES PROJECT
OIL-FIELD FLARE GAS ELECTRICITY SYSTEMS

PIER FINAL PROJECT REPORT

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

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- Environmentally Preferred Advanced Generation
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- Renewable Energy Technologies
- Transportation

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For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916□654□4878.

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Abstract

Extracting oil in declining oilfields has become more difficult and expensive. About a third to one half of the cost of extracting oil from a well is the cost of energy expended to recover the oil. Most oil wells also generate gas of varying quantities. While some of the gas may be of quality suitable for pipelines, a significant portion of the gas cannot be delivered to a gas pipeline, as it is either too high or low in energy, too corrosive, too far from a pipeline, or too small a quantity to justify. This "stranded" gas often has nowhere to go and must be suppressed. A pressure bubble is created by the suppression and reduces oil production. Producers are forced to vent, flare, re-inject or incinerate the stranded gas resulting in energy waste, a step backwards from greenhouse gas reduction, and an increase in emissions. The Oil-Field Flare GAS Electricity Systems Project was conceived to find practical ways to consume stranded gas from oil wells in California. The project focused on four representative sources of oilfield stranded gas:

- High British thermal unit Gas
- Medium British thermal unit Gas
- Low British thermal unit Gas
- Harsh Gas

Keywords: Air quality permitting, building and safety permitting, combined heat and power (CHP), COPE California Oil Producers Electric Cooperative, DG distributed generation, electrical interconnection agreement, flare, harsh gas, high BTU gas, low BTU gas, microturbine, Oil-Field Flare GAS Electricity Systems, oil field flare, power export, self generation, standard offer tariff, stranded gas

Executive Summary

Introduction

Over the last several decades, oil production in California has steadily declined as existing oilfields have gradually become depleted. Between 1985 and 2005, the price of oil in California has ranged between $8.00 and $20.00 per barrel. Much of California's oil production was marginal at best and many wells that were capable of producing oil were shut down or in some cases abandoned because they were not economically viable to operate.

It was under these circumstances, before the recent oil price spike, that the California Oil Producer's Electric Cooperative began the "Oil-Field Flare GAS Electricity Systems" Project. California Oil Producer's Electric Cooperative members represent over 90 percent of the oil production in California. All oil-wells produce some gas in addition to the oil; some of this gas is pipeline quality and some of it is convertible into pipeline quality gas, but a large portion of the gas is unsuitable for pipelines. Due to the Southern California Gas Company Rule Number 30 regarding specifications[1] for pipeline quality gas, more gas has been stranded since it is no longer considered suitable for pipelines.

Purpose

The Oil-Field Flare GAS Electricity Systems Project demonstrated four separate solutions for waste gases:

- Medium British thermal unit Gas, 800-1300 British thermal unit
- High British thermal unit Gas, over 1600 British thermal unit
- Low British thermal unit Gas, below 350 British thermal unit
- Harsh Gas (with sulfur, nitrogen or CO_2 contaminants).

Project Objectives

The original objective of the Oil-Field Flare Gas Electricity Systems Project demonstrated how the four different types of waste gases could be converted to energy using microturbines. In addition, the project showed that gases whose properties were in between those tested could also be effectively used. Almost all oilfield stranded gas could be converted to useful energy.

The goal of the project was to select the best technology for each application; to evaluate how well the technology lived up to its expectations on reliability, emissions and costs; and whether the technology can be cost effective for the producer.

Project Outcome

Medium British thermal unit: The first test site selected was a medium British thermal unit site located south of downtown Los Angeles. Gas from the site was previously sold to a local gas company. However, the gas did not consistently meet the Southern California Gas Company Rule Number 30 regarding specifications on natural gas quality and the gas company had to

1. Quality specifications regarding heating value, moisture content or water content, hydrogen sulfide, mercaptan sulfur, total sulfur, carbon dioxide, oxygen, inerts, hydrocarbons, merchantability, hazardous substances, delivery temperature, interchangeability, liquids, landfill gas, and biogas.

shut down the gas system every time gas quality didn't meet specifications. Each shutdown by the gas company disrupted the gas and oil flows.

The wells at this site were producing in several different production zones and the gas energy content at the site varied between 800 and 1400 British thermal units a cubic foot, depending on the well and the zone from which it was produced. The producers of this site agreed to treat its gas production so that it could be split into two types: one that met pipeline quality, and one that did not. The gas that did not meet pipeline quality would be used to power three microturbines.

Capstone microturbines were selected for this site. Due to the positive results of the project, the client has acquired nine more turbines and is planning to add them to their other sites.

High British thermal unit: The second test site selected was the high British thermal unit site in Signal Hill, California. The stranded gas at this site was rated at 1,763 British thermal unit a cubic foot. This project also used a Capstone microturbine that the client had already obtained. The field had been idle for several years without a solution for the stranded gas produced. After returning the wells to production, the gas flow declined substantially producing about 75 percent of the gas needed to run the microturbine. The first attempted solution was to run the turbine intermittently, however this was too hard on the equipment which is designed for continuous operation. After some experimentation, reprogramming, and adjustments the turbine was able to run continuously at a lower power output consuming all available gas and has been in near-continuous operation since. At this site, the turbine was responsible for returning three idled wells into service, and increased oil production by about 35 barrels per day. The client is considering microturbines at other sites to use the lower quality gas.

Harsh Gas: The site selected for harsh stranded gas was in the Maricopa area near Taft, California. At this site, the gas had high amounts of hydrogen sulfide, in the range of 5,000 to 6,000 parts per million and its energy content was low, about 500 to 700 British thermal unit per cubic foot. To meet air quality requirements, the sulfur had to be significantly reduced. Removing hydrogen sulfide on a large scale is widely practiced in refineries and elsewhere, but at a small scale operation it is difficult to find cost-effective hydrogen sulfide removal systems. An Ingersoll Rand microturbine was used to demonstrate another turbine technology. The project also uses waste heat from the turbine exhaust to heat the oil to assist with water removal and freed up additional gas that was previously used to generate the heat in boilers.

Low British thermal unit: As with high British thermal unit and harsh gas sites, there was much interest among California oil producer in hosting the low British thermal unit site. Several operators volunteered, and a site north of Ventura, California was selected. This site processes off-shore oil production; water is first stripped from the oil; then gas is stripped from the oil. The gas contains a high percentage of carbon dioxide, which must be removed to bring the gas to pipeline quality. The carbon dioxide contains residual hydrocarbons, mostly methane, and has a heating value of only 15 to 42 British thermal units a cubic foot. The carbon dioxide was processed through a thermal oxidizer where the residual methane and hydrocarbons were destroyed. The thermal oxidizer uses 200,000 cubic feet natural gas to destroy the hydrocarbons in the low British thermal unit gas.

The Flex-Microturbine, although not yet fully commercial technology, was the only feasible way to convert the low British thermal unit gas into electricity. Flex-Microturbines are designed to run on gas as low as 15 British thermal units per cubic foot or on stronger gas without a major retrofit. If Flex-Microturbines could replace the thermal oxidizer, 200,000 cubic feet a day of natural gas would be saved, a value of about $1,200 to $2,000 a day, or $400,000 to $700,000 a year. In addition, the site would generate 80 kilowatts of electricity for internal use or sale. Unfortunately, the project ran out of funds, and the low British thermal unit gas project was prematurely terminated.

Conclusions

Overall, this project was a technical success. The project demonstrated the ability of small oil producers to install, operate, and generate electricity using stranded gas as a free waste product fuel. There were many failed attempts prior to this project. Some of the oil producers participating in this project had previously attempted distributed generation on their own and had experienced a lot of frustration in obtaining the permits and approvals necessary from air management districts and local municipal districts. Obtaining proper tariff from local electrical utilities, finding good economical maintenance programs and solving noise mitigations problems were other unresolved challenges. This project met all these technical challenges and in many cases developed simplified tools to accomplish these tasks. All four participating companies are actively looking for ways to increase using distributed generation at their sites and other sites they operate.

Two of the four sites were successful economically. Restoring idle oil fields to production was successful, however additional work must be done to assure that all projects are economically feasible.

Recommendations

Two areas still requiring further work are the economic viability of the projects and further development of the ultra low British thermal unit turbine.

- Economics: Typically medium to small oil fields produce several times more stranded gas than they can consume at their oil fields. Today the utility can accept this extra electricity without compensation, but often will not. There are currently no tariffs that will allow the sale of power below one megawatt. Because this power is not considered "renewable" there is no incentive for the utility to take this power and pay for it, and no incentive for the oil operator to develop projects when there is an option to flare the gas. There will be few distributed generation projects until standard offer contracts to purchase the excess power are available.
- Further development of the ultra low British thermal unit turbine: This project demonstrated that the Flex turbine was viable operating in difficult oil field conditions. Further development is needed to expand the reliability and to make the Flex turbine commercially viable.
- Consider changes to state policies to make producing clean and inexpensive energy economically viable for the oil field operators, and develop regulations that allow easy access to markets for the sale of power generated from stranded gas.

Benefits to California

Flaring is permitted by California's air managements boards, however if all flaring were converted to distributed generation, over 400 megawatts could be generated. Additionally the electric power generated by converting non-pipline quality stranded gas currently burned in boilers to combined heat and power could exceed 2,000 megawatts.

Since flaring and boilers typically emit much higher amounts of nitrogen oxides, and other greenhouse gases, changing to more environmentally friendly energy generating processes would contribute to reducing greenhouse gas emissions.

1.0 Introduction

This project addresses a significant problem in California. As California's oil production declines, it becomes increasingly more difficult to extract oil from oil-wells with less of the total fluids produced as oil and more of it as water. Oil production also includes some gas production. When such gas cannot be conveniently sent to gas pipelines, it becomes "stranded" from commercial markets and a problem for the producer. For most of California's oil production history, gas production, even when it is not stranded, has been considered a low value fuel. The gas must be disposed of in order to allow continued production of the higher value oil production.

In some instances, even pipeline quality gas cannot be sold because there are no natural gas pipelines nearby; similarly, many urban natural gas pipelines are shutdown because of encroaching urban renewal. This is especially challenging in the Los Angeles Basin with its recent proliferation of high rises through several existing oilfields. Gas that cannot be sold via natural gas pipelines must be suppressed, flared or vented. In the Los Angeles basin, venting is not acceptable because of the potential impact on nearby dwellings and businesses; even flaring is increasingly limited because of emissions limitations. If the gas is suppressed or re-injected into the well, it stymies oil production.

California has extremely rigid air emission standards for electrical generators. This electric power generation reduces emissions. The electricity generated from waste gas would offset the high cost of power otherwise purchased by the oil producer, shifting the economics significantly in favor of production. If successful, Oil-Field Flare GAS Electricity Systems (OFFGASES) would generate more power for California, reduce oil production costs, increase oil production and reduce emissions as well. At the national level, the benefits of increased oil production would reduce import needs. On a global scale, the OFFGASES project will reduce methane from vented gas, reduce Nitrogen Oxides (NO_X) from flares, and reduce carbon dioxide (CO_2) by offsetting generation elsewhere, helping meet the goals of the Greenhouse Gas Emission Standards, AB 32. Attachment I shows the rise of stranded gas in California in recent years.

This project seeks to find means to make electricity from the energy in stranded gas. The electricity may be used by the producer, or sold to the utility. If the gas that is currently being

flared or vented were consumed in electrical generation, up to 400 Megawatts (MW) of electricity could be generated. This power would require no additional fuel, thus saving fossil fuel imports, and be better for the environment. With new technologies now available, an additional 2000 MW that could be generated from the gas behind shut-in wells or wells once considered uneconomic and by conversion of direct heat to Combined Heat and Power (CHP).

In order to cover as many types of stranded gas as possible, the project decided to focus on four separate streams of stranded gas commonly found in California. These streams are:

- Medium Btu gas, 800-1300 British thermal units (Btu)
- High Btu gas, over 1600 Btu
- Low Btu gas, below 350 Btu
- Harsh Gas (with sulfur, nitrogen or chlorine contaminants)

Almost all stranded gas falls into one or more of the above categories. The measure of technical success was to demonstrate that each of the four streams can be converted into electricity, or to show why not, and recommend alternate solutions.

The measure of economic success was measured from three points of view: the producer's perspective, the state's perspective and the national perspective. In addition, an assessment was made to recommend whether or not surplus power generated from stranded gas should be purchased by the utilities, and at what cost.

All sites selected were within the state of California, at either the Bakersfield or Los Angeles Basin oilfields. Many of these oilfields have been producing for over one hundred years, and production is generally in decline. If the cost of production from these wells can be reduced, and if an outlet can be found for stranded gas, oil production will increase in some cases and will continue longer in all cases.

The technologies to be considered for power generation include traditional technologies such as internal combustion engines, steam and gas turbines; they also include recently developed technologies such as fuel cells, microturbines and Stirling engines. The goal of the project was to select the best technology for each application, to evaluate how well the technology lives up to its expectations on reliability, emissions and costs, and whether the technology can be cost-effective for the producer.

Each of the sites was required to have appropriate building and safety, interconnection and air quality permits.

2.0 Project Approach

2.1 Project Goals

The goals of the project were:

- Demonstrate solid, repeatable, means to use stranded gas at oilfields for clean, electric power generation.
- Examine the economics of using stranded gas
- Find pathways to economic solutions
- Identify technology and regulatory bottlenecks and recommend means to remove them
- Transfer the technology lessons to oilfield operators and regulators

The first phase of the project was to meet with as many California oil producers as possible, present them the project goals and to seek their participation by providing suitable sites. This was done by preparing a presentation on the goals of the project, the methods to be used, and the anticipated results. California Oil Producers Electric Cooperative (COPE) initially conducted two seminars to disseminate the information: one in the Los Angeles area, and the other in Bakersfield. COPE members and non-member oil producers were invited, and over fifty people were in attendance at each of the seminars. Avid discussions took place, and 34 members and non-members provided details of their stranded gases. These details are included in Appendix C and provide a list of the companies that submitted proposed project sites and gas qualities submitted by seminar attendees.

From the information received, COPE and its partners evaluated the best potential sites for each of the four sub-projects. There were several candidates for each site, giving credence to the assumption that stranded gas is a major problem.

2.2 Project Plan: The Four Demonstration Sites

2.2.1. Medium Btu Site

The first site selected was the medium Btu site. Medium Btu was chosen for two reasons: it was the least challenging of all the sites, and it would provide a benchmark for the other sites.

The medium Btu site chosen was the St. James' Oilfield in Los Angeles, south of downtown, near the Staples Arena. Los Angeles has been a major oilfield for one hundred and fifty years. In most situations, as in St. James, down hole pumping is required to bring the oil to surface. St. James once had pipelines interconnecting to other oil wells in the area, where surplus gas or oil could be transferred back and forth to help meet specifications. However, with the building boom downtown, rights of way for oil pipelines have been revoked, and St. James must now operate independently.

The problem at St. James was that its gas did not meet the new Southern California Gas Company's Rule Number 30 regarding pipeline quality requirements. St. James total mix of gas was about 1250 Btu per cubic foot, while pipeline quality gas must be no more than 1150 Btu per cubic foot. The higher end hydrocarbons, such as C4s and C5s, had to be removed to meet quality requirements. The gas company required installation of a continuously monitoring gas chromatograph at the entry to its pipeline. When the chromatograph detected unacceptable gas

quality, it shut down the gas which shut down the entire oil field. These shutdowns not only disrupted gas flow, they also disrupted oil flow. With no home for these high end hydrocarbons, St. James faced a dilemma, and was shut down for over three years prior to our project. To compound the problem, a gas pipeline to a nearby set of wells that could have provided relief by blending this gas with lower Btu gas was abandoned after construction of high-rise buildings in the vicinity appropriated the right-of-way.

An additional problem arose as a result of a steady flow of gas to the pipeline. The field is located in a very urban part of Los Angeles and at times, especially in the summer months when gas usage is low, there is not enough room in the pipeline for the total flow of gas from the oil field. The field then has to be shut in because there is once again no outlet for the gas production.

The solution proposed by COPE was to separate the high end fractions, thus meeting pipeline quality requirements for the bulk of the gas. The high end fractions would be used to generate electric power for use at the facility. This was by no means an easy solution because most power generating equipment also requires gas of stable, consistent quality. It was the sort of challenge that COPE wanted to resolve.

COPE met with the South Coast Air Quality Management District (AQMD) to make sure that air emissions from the site would be satisfactory. During discussions, it was learned that the AQMD had a few microturbines available for deployment in a manner to improve air quality. The AQMD agreed to provide COPE with three 30 kilowatts (kW) Capstone C30 microturbines that would be used for St. James.

This sub-project were comprised of:

- A gas refrigeration unit to separate the high end hydrocarbons
- A fuel compressor for all three units
- A moisture removal system to remove free water in the gas
- Three Capstone C30 microturbines
- Related controls, interconnections, electrical meters, gas meters, and other systems

The project went reasonably well. The microturbines were refurbished by the manufacturer. Manufacturer warranties were reestablished and the equipment was installed at the site. The gas stripper and moisture removal systems required several weeks of trouble-shooting before they functioned acceptably.

While noise from the C30s was within City of Los Angeles specifications, there were complaints from the neighbors. This was, after all, downtown Los Angeles. The C30s emit a high pitched sound, not unlike that of a jet engine. Several methods of sound-proofing were tried. Capstone recommended a sound absorbing shroud around the intake and back of the units. This eliminated some of the noise, however; noise complaints from the neighbors continued. We found a vendor that had an audio blanket that was designed to absorb the specific frequency of noise that the C30s emitted. This audio blanket was the final solution as the complaints from the neighbors' ended.

The St. James' system has now been in operation for over three years. The client is satisfied with performance. Since installation, shut-downs due to gas being out of specification have been reduced to a minimum. Oil production has resumed to 80 bbl per day. The client has obtained nine additional microturbines and plans to use them when the oil-field expansion plans are implemented.

The economics of the project are best summarized from the client's perspective. Prior to the project, the client was not able to deliver gas, and thus also not able to produce oil. Since the project, the client is producing and selling natural gas, producing oil, and also generating 80 kW of electricity for internal use. The payback on investment is significant.

Appendix A includes drawings providing details of the site.

Appendix B includes site and installation photographs.

2.2.2. High Btu Site

The selected high Btu site was the Termo oilfield in Long Beach north of Signal Hill. This oilfield has been tapped for well over a hundred years, and continues to produce.

At Termo, the gas concentration was over 1,700 Btu a cubic foot, with a large fraction of C4s and C5s. This gas could not be put into a pipeline. The client had installed a separator to add the high ends to the oil, thus sweetening the oil, but the remaining gas was still too rich for the pipeline and remained stranded.

A microturbine was installed by the client at his other oil operations, but had not run well and was shut down most of its time. The site had been experiencing problems related to design changes to the on-site compressor, and was prone to gas production and Btu fluctuations.

After some consideration, it was decided that the best solution at Termo was to tune the microturbine in such a manner that it would be able to handle the fluctuating gas flow rate. These changes would make the machine a fuel-follower, using all the fuel gas available at any time, thereby resolving the problem of fluctuating fuel supply.

The solution has worked well. The system now operates around the clock, and has shown an availability of over 85% over the last three years.

Appendix B includes pictures of the installation.

The client is happy with the resolution of the problem. Thanks to the microturbine consuming all gas at site, oil production has increased from 0 to 35 bbl per day. The client is planning to install additional microturbines at his other oilfields, using the solution developed by the OFFGASES Project to consume the gas.

The economics of the project are best summarized here by the client's perspective; the value of the power generated was small compared to the increase in oil production and the accompanying confidence in future production. The savings amounted to $19,000 a year from power and $1,000,000 a year from increased oil revenues.

2.2.3. Harsh Gas Site

There were several candidate sites for harsh gas that is stranded. Of these, the site selected was the Maricopa site belonging to Drill-Pro, a small oil company. Maricopa is located 80 miles north of Los Angeles, and about 30 miles east of Bakersfield, California. The site has several oil wells, with no gas pipeline nearby so all gas was being flared. The challenge was that the gas had high sulfur content, in the range of 5,000 to 6,000 ppm of sulfur in the form of Hydrogen Sulfide (H_2S). The high sulfur content is hard and corrosive on the generating equipment and created air emissions that did not meet air management standards and made the gas difficult to use for power generation.

Several solutions were considered for removal of the sulfur. The problem was that most sulfur removal processes are intended to process high volumes of gas flow, and cannot be economically scaled down to the size needed for this project. The research effort was to find the best sulfur removal system for this site.

The SulfaTreat process is a chemical reaction that removes the hydrogen sulfide from a gas stream via specially designed reactant products. The apparatus consists of a fixed-bed or batch-type granular hydrogen sulfide reactant contained in a pressure vessel. During the process, sour gas or vapor flows through the granular SulfaTreat product in the bed, where the hydrogen sulfide reacts with the reactant to form a stable and safe by-product. The system is tolerant of variations in gas flow and content. From time to time the bed must be replaced. The project achieved this without major shutdowns by having two beds, one primarily for removal and the second for polishing. When the first bed is spent, flow is diverted to the second bed while the first bed is replenished and brought back on line as a polisher.

The medium and high Btu sites both used Capstone Turbines. In order to test a different system, an Ingersoll Rand 70 kW (IR70) turbine was chosen for this location. The system has two separate turbines, one for the generator and the other for the air compressor. Unlike the Capstone, the IR70 is a fixed speed machine, running with a gear-box and a traditional synchronous generator.

The SulfaTreat system was consuming significantly more reactant than anticipated, and had to be replenished much more frequently, an unplanned expense. With careful tuning, the quantity of reactant used has been reduced, and it is hoped that it can be reduced further.

One problem unique to this site was that the client did not have adequate local load to consume the power generated by the IR70. Compounding this problem, as a fixed speed machine, the IR70 does not perform as well at partial loads, and the manufacturer did not want the system operated below 90% load. While gas was available to run the machine at high power, if there was no load on site, the power would have to be exported to the utility. The client was willing to give away the power to the utility at no charge.

This seemingly simple fix turned out to be a challenge. Pacific Gas and Electric (PG&E) was not initially willing to accept the "free" electricity. It required a study, and then required the addition of a ground-bank and other devices as a condition for allowing a limited amount of power into its system. During periods of low demand, the power delivered to the grid would sometimes exceed the limit. The utility would shut down the generating system every time the power delivery reached the limit. These shutdowns triggered a demand charge and a stand-by charge for the electricity needed by the client to replace the lost power. The stand-by and demand rates were so high that any savings generated from power production were more than offset by the costs. The client installed a bank of electrical heaters, just to dissipate surplus electricity to avoid stand-by and demand charges.

This project is not yet cost-effective and by far the least from showing an economic success of the four projects. The high costs of sulfur treatment and the high cost of generating surplus power are the key factors that make the project uneconomical.

There are many oilfield sites that face this dilemma. Many sites that have stranded gas do not have sufficient electrical demand to consume all power generated. If utilities do not buy the power, this vital fuel is wasted, increasing NO_X and hydrocarbon emissions, when it could be used to generate power.

The client has the potential to generate at least another 500 kW at this site, but unless a reasonable price is available for the electricity generated, will continue to flare the gas.

Appendix C shows gas quality, Appendix B shows pictures of the installation.

2.2.4. Low Btu Site

As with the other sites, there were several candidates for the low Btu gas. The site selected was the DCOR Rincon facility. At Rincon, oil from several offshore oil rigs is brought ashore. The

water is stripped from the oil, after which gas is stripped. The gas contains high amounts of carbon dioxide. The carbon dioxide is removed from the gas using an amine plant, and the flow of CO_2 is about 500,000 cubic feet a day. The problem is that the CO_2 contains small amounts of hydrocarbons, and the facility has to destroy the hydrocarbons before the gas is vented into the atmosphere.

The tail gas contains hydrocarbons expressed as between 1.5% and 4% methane. In order to destroy these hydrocarbons, the tail gas was being processed through a thermal oxidizer that consumes 200,000 cubic feet of natural gas a day providing the heat to destroy the hydrocarbons.

The project therefore undertook to find a way to use the hydrocarbons in the tail gas for power generation. There were two potential solutions:

- Concentrate the hydrocarbons to the extent that they could be used in a conventional power plant.
- Look for a power plant that could run on 1.5% to 4% methane in a gas stream.

Technologies for concentrating the methane were expensive, and the energy used in the process would probably be greater than the energy recovered. It was therefore decided to look for a power plant that could handle the low Btu gas. The only system available was FlexEnergy's Flex-Microturbine that runs on 1.5% methane or higher. Even though the technology was not yet commercial, it held sufficient promise that it was decided to use it.

A 30 kW Flex-Microturbine was installed at the site. It was started up with high Btu natural gas and then weaned over to low Btu gas. The system operated reasonably well for periods, but it was discovered that the "quality" of the low Btu gas was not consistent. Emissions from the Flex-Microturbine are well below 1 ppm, the lowest of any current power plant.

The system operated reasonably well even though there were a couple of start-up related failures due to a bad compressor wheel and an overheated catalyst. Unfortunately, the project ran out of funds, and the endurance testing could not be completed.

The Flex-Microturbine has drawn a lot of interest with oilfield operators. An interesting feature is that even though it was chosen for the low Btu site, the same system could have been used for medium or high Btu. The Flex-Microturbine accepts gas at atmospheric pressure, and then dilutes it with air to the desired 15 Btu/scf threshold. This means that all fuels no matter what their initial strength can be used in a Flex-turbine, giving the opportunity for the one-size-fits-all solution that oilfields prefer.

Appendix A shows site drawings.

Appendix B shows installation pictures of the Flex-Microturbine at the Rincon site.

3.0 Project Outcomes

3.1 Economic Issues

3.1.1. Medium Btu

The medium Btu site had a significant payback potential because both oil and gas were being suppressed as a result of tight gas quality requirements. All 90 kW of power generated by the microturbines could be used on site and there was no need to export power. When a solution was found that allowed both gas and oil production to increase, and with a big increase in oil prices, the project proved to be economically sound. The total project cost was $497,000, providing a payback of 2.5 months. The $497,000 resulted in an oil production increase of 80 barrels a day, and gas production of $950 a day; the benefit is about $2,700,000 a year. The value of the power generated, while helpful, was a minor cost relative to the overall savings. The client is considering adding several more microturbines.

3.1.2. High Btu

At this site, too, stranded gas had eliminated oil production for over three years. A microturbine installed by the client at his other facilities had not been successful. The client decided to try and install the microturbine at his Long Beach facility and solicited the help of the OFFGASES team. From our experience at the Medium Btu site a resolution of the technical issues was found and oil production was reestablished initially at 15 barrels a day, and eventually increased to 35-40 barrels per day. Project cost was $397,000; benefits are $1,000,000 a year, with a payback of 4.5 months. This client is considering installing microturbines at its other sites.

3.1.3. Harsh Gas

The economics of this project were more complex. In order to use the harsh gas, it was necessary to remove sulfur from the gas. The sulfa-treat system operation costs, which were largely the cost of chemicals consumed, is averaging $325 a day; there was no immediate benefit from oil production because the client was already able to flare the gas. The project had to stand on the value of power generated. The site power requirements were less than the power generated by the turbine, but the utility would neither accept nor pay for surplus power generated. The utility finally relented and accepted a small amount of surplus power without payment. Even so, whenever the power exceeded the limit, the utility would shut down the power plant. The shutdowns meant that the client had to buy additional, high priced power from the utility, and incur high standby charges. The higher pricing negated all savings to the client from power generation. The client then installed a resistance heater bank, dissipating the surplus electricity just to keep the utility from shutting down the system.

Between the cost of sulfur removal and the limited opportunity to generate power, the economics of this project did not materialize. The unable situation resulted in a waste of electric power, and unnecessary emissions. A change in tariff that requires utilities to purchase all power from stranded gas would eliminate this problem.

The project cost was $262,000, the annual savings at this time are only $22,000, with a payback of 11.8 years. Should the proposed stranded gas tariff be implemented, the annual savings will

be between $45,000 and $63,000, making a significant difference. If the stranded gas tariff is implemented, the site owner plans to put in an additional 250 kW generator, which would generate between $203,000 and $286,000. This would reduce the amount of flaring to emergency use only and would consume nearly all of the stranded gas.

3.1.4. Low Btu

The economics of the low Btu site were compelling. The site "destroyed" 500,000 cubic feet of 15 to 45 Btu gas a day in its thermal oxidizer. The oxidizer consumed 200,000 cubic feet of natural gas a day, at a cost of $1,500 a day. If the low Btu gas could have been used to generate power, the fuel savings would be about $500,000 a year, a major difference compared to the value of the power generated, which was only $30,000 a year. The project had spent about $329,000 when funds ran out. During this time, a Flex-Microturbine was installed and operating. Had the project been completed as planned, the project payback period would have been less than one year.

Unfortunately, circumstances changed during the project. The client had a CHP system that provided heat for oil operations, but in 2007 the turbine combustor was destroyed in a fire. The thermal oxidizer became the only source for heat at the site. It is now fired with about 400,000 cubic feet a day, and now there is no fuel benefit to destroying the low Btu gas in a turbine. The client is now looking at alternate means to generate power with its surplus gas.

3.2 Regulatory, Electrical Tariff and Public Policy Issues

The largest impediment to the success of these "stranded gas to electricity" projects is still in the regulatory, electrical tariff and public policy areas. These issues hamper the smaller independent oil operators much more than the larger oil operations. Large oil production operations have more options to deal with stranded gas than just distributed generation. The smaller operations often have more stranded gas generating capacity than they have electrical load to consume, and today export of that power is not an option for the following reasons:

- **Regulatory.** There is a strong market of electrical purchasers wanting to purchase electric energy that is produced in an environmentally friendly way. Some businesses and households are willing to spend a premium if the electrical power is produced in a way that helps the environment. Compared to traditional renewable power sources, (wind, solar, biomass and landfill), stranded gas generation is much cheaper to produce. Because it is not classified as renewable under current regulations, it is nearly impossible to sell power from stranded gas projects. Regulators need to work with utilities and industry to develop regulations that allow recognition and easy access to markets for the sale of this power.

- **Electrical Tariff.** The PURPA act of 1978 Requires that all "QF" qualified projects be offered a Standard Offer contract to sell power to the utilities at "SRAC" prices. It is up to each state to set the formula from Short Run Avoidance Cost (SRAC). The SRAC formula in California has needed modification for nearly a decade. There has been a ongoing dispute between the electrical utilities and industry over this formula. The California Public Utilities Commission, which approves contracts between utilities and industry, has discouraged new standard offer contracts until the SRAC issues have been resolved, therefore only renewal of existing standard offer contracts have been attempted during this time period. The California Independent System Operator (CAISO) Schedules the power to the electrical grid. It has a minimum of 1,000 kW, or 1MW from any generating location. The addition of the potential 200 MW to 2,000 MW from stranded gas generation would be a great asset to the CAISO. However, development of this additional generation would require the CAISO to drop its minimum threshold down to 100 kW, thereby allowing smaller DG projects to

participate.

- **Public Policy.** Power produced from stranded gas reduces air emissions from flaring, venting of natural gas, and boiler steam generators through CHP; however these projects currently receive no credit or recognition reducing greenhouse emissions. California has a requirement for renewable energy to be the source of at least 20% of the total electricity sold by in the state. The state's retail sellers of electricity are generally a long way from complying with this requirement. As required by state law, the Public Utilities Commission annually develops a set of Market Price Referents (MPR) to compare against power supply contracts using renewable energy sources. The MPR is the cost of electricity ($/kWhr) below which renewable energy source power supply contracts will not require above market payments. Electricity produced from stranded gas does not qualify as renewable under state law, but can provide a low-cost, environmentally beneficial source of power. However, electricity from stranded gas receives no clear benefit from public policy mechanisms and therefore no benefit or recognition is given to those who develop the projects and no benefit or recognition is given to those who purchase the power from these projects. Public policy should in some way support all forms of environmentally friendly generation.

4.0 Conclusions and Recommendations

The OFFGASES project showed that all oilfield stranded gas can be used to generate electric power. Whether stranded because it is high Btu, low Btu, harsh gas, or simply because it cannot be conveniently delivered to a pipeline, the gas can be utilized. In many cases, the cost of generating the electricity may be offset by gains in oil production. In other cases, the cost of power generation may be offset by reduced purchase of electricity. For oilfields that do not have a high electricity demand, there are currently no outlets available to sell the electricity. This constraint results in waste of an important fuel, for the gas is otherwise vented, flared or re-injected, and results in reduced oil production. It also results in increased emissions, because flares generally produce significantly more NO_X than distributed generation power plants.

The problem with stranded gas would be significantly smaller if utilities were required to purchase all power from stranded gas at reasonable rates, allowing oil producers to develop projects that would reduce emissions, increase oil production, help towards energy self-sufficiency, reduce greenhouse gas emissions, and create jobs.

5.0 Technology Transfer Program

The Technology Transfer program has been a big success. The IOGCC has already published several articles in trade journals and industry publications touting the success of the project. It has also developed a brochure on the OFFGASES Project. Attachment II includes copies of these publications.

COPE has presented the OFFGASES Project at two annual meetings of the IOGCC.

Several meetings during the course of the project were held at the Petroleum Technology Transfer Committee (PTTC) where the major topic of discussion was the OFFGASES Project.

Copies of these meetings and seminars can be found in Appendix D.

Already several oilfield operators are looking for solutions such as those developed by the OFFGASES Project. Technology Transfer was successful.

6.0 Glossary

AQMD	Air Quality Management District
BTU	British Thermal Units
CAISO	California Independent System Operator
CARB	California Air Resources Board
CEC	California Energy Commission
CHP	Combined heat and power
CO_2	Carbon dioxide
COPE	California Oil Producers Electric Cooperative
CPUC	California Public Utilities Commission
DG	Distributed Generation Technology
DOE	U. S. Department of Energy
H_2S	Hydrogen Sulfide
IOGCC	Interstate Oil and Gas Compact Commission
IR	Ingersoll Rand
kW	Kilowatt or thousand watts
LADWP	Los Angeles Department of Water and Power
mcf	thousand cubic feet
MW	Megawatt or million watts
NETL	National Energy Technology Laboratory
OFFGASES	Oilfield Flare Gas Electricity Systems
PAC	Project Advisory Committee
PG&E	Pacific Gas & Electric
PIER	Public Interest Energy Research
PUMP	Preferred Upstream Management Practices
PURPA	Public Utilities Regulatory Policy Act
QF	Qualifying Facility (under PURPA guidelines)
R&D	Research and Development
SCAQMD	Southern California Air Quality Management District
SCE	Southern California Edison

SRAC	Short Run Avoidance Cost (cost of utility to turn on additional electrical generation. This cost is used to set the price of power from QF projects)
scf	Standard cubic feet

Arnold Schwarzenegger
Governor

APPENDIX A
SITE DRAWINGS

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Bob Fickes
California Oil Producers Electric
Cooperative (COPE)

December 2008
CEC-500-02-016

Prepared By:
California Oil Producers Electric Cooperative
Bob Fickes
Long Beach, California 90802
Contract No. 500-02-016

Prepared For:
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ENERGY RESEARCH AND DEVELOPMENT DIVISION

Melissa Jones
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DISCLAIMER

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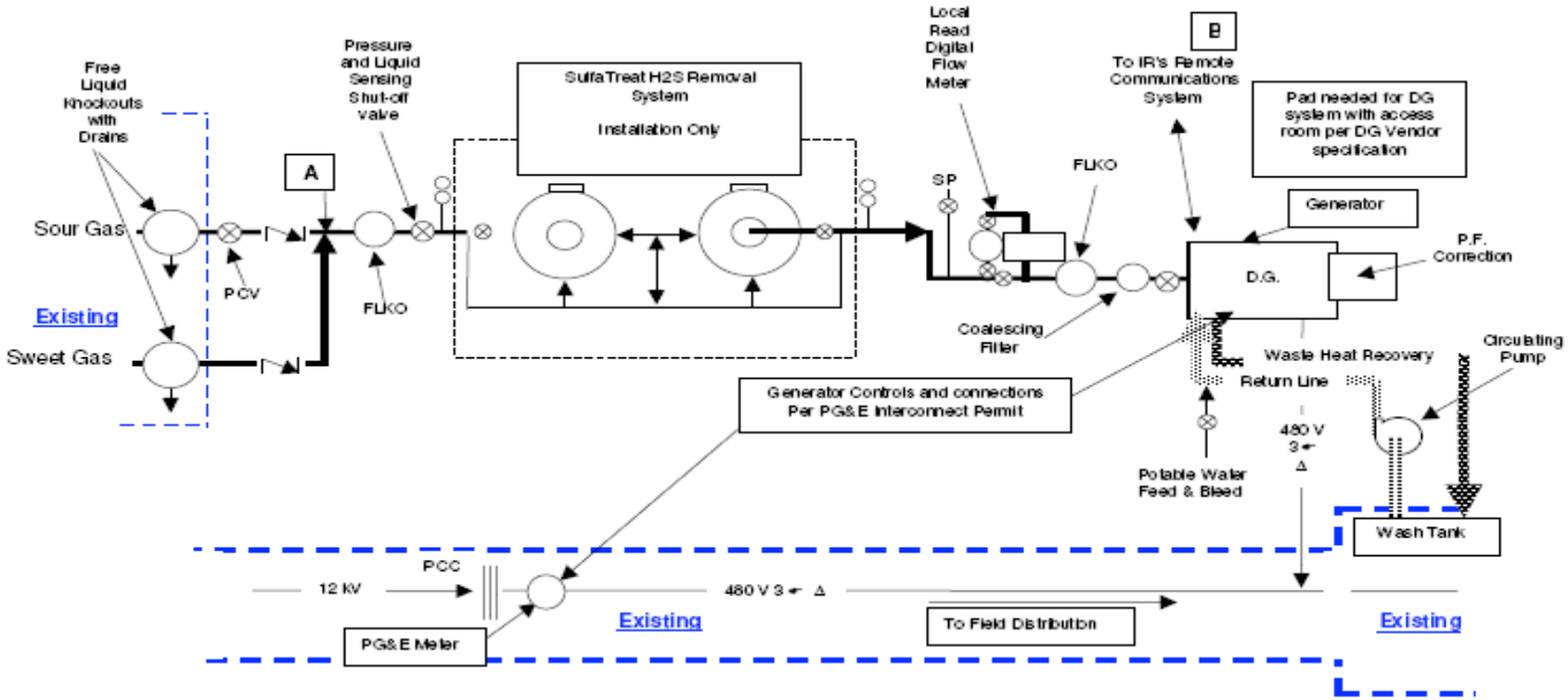
HARSH GAS
SITE DRAWINGS



A

DrilPro says that the field will automatically equalize the Sweet and Sour Gas pressures at this point.

B

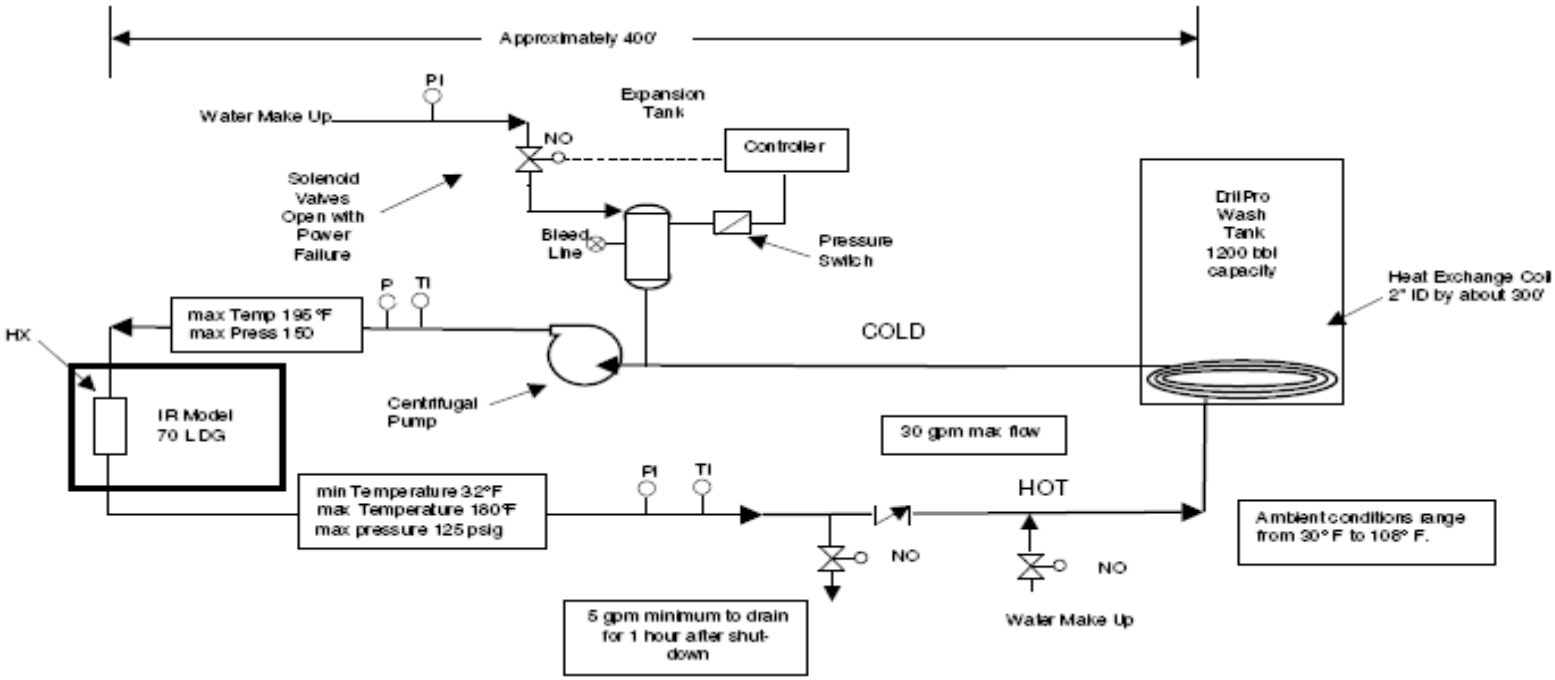
Data as Provided by IR Remote Communications System and listed on pages 23, 24, and 25 of the 70 Series Remote Communication Manual

Pressure & Temperature Gauges

COPE Offgases Project - Flow Diagram
Harsh Gas Site - Drilling & Production, Maricopa

Mechanical & Electrical Arrangements

Jul 06 jch/cwz Sketch 100 rev 18



COPE Offgases Project, Harsh Gas Site
Drilling & Production Company, Maricopa, California

Heat Transfer Loop Arrangements
No Scale

Jul 06 jch/cwz/rt Sketch 105 Rev 6

HIGH BTU
SITE DRAWINGS

PREPARED BY:

POWER ENGINEERING SERVICES, INC.

2703 SATURN STREET

BREA, CALIFORNIA 92821

714-524-9100

THOMAS M. HILL

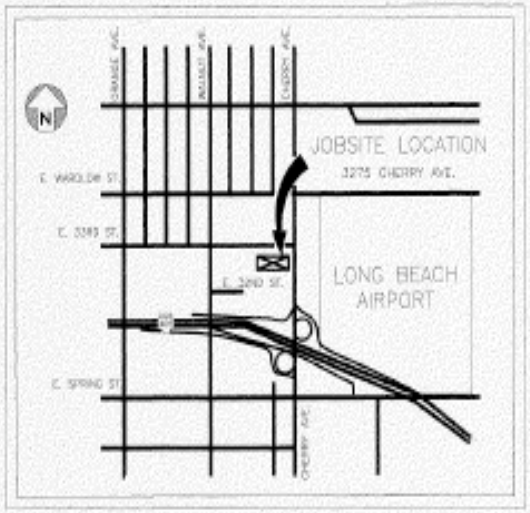
LICENSE E8615

PREPARED FOR:

THE TERMO COMPANY

3275 CHERRY AVENUE

LONG BEACH, CA 90801



SITE MAP

DRAWING INDEX

DRAWING NUMBER	TITLES
3134-04-D100	TITLE, INDEX AND GENERAL NOTES
3134-04-E101	SINGLE LINE DIAGRAM
3134-04-D102	POWER PLAN
3134-04-D103	ENLARGED PLAN, SECTIONS & DETAILS
3134-04-D104	GROUNDING DIAGRAM AND INTERLOCK DIAGRAMS

GENERAL NOTES

1. BIDDERS SHALL CAREFULLY EXAMINE THE ENTIRE SCOPE OF WORK. BIDDERS SHALL MAKE ALL INVESTIGATIONS NECESSARY TO BE THOROUGHLY INFORMED ABOUT THE WORK, REQUIRED SCHEDULING, PLACING AND USING THE NECESSARY EQUIPMENT AND MATERIALS, AND SPECIAL METHODS INVOLVED IN COMPLETION OF ALL WORK IN ACCORDANCE WITH THE PROJECT DRAWINGS, SPECIFICATIONS AND CONTRACT DOCUMENTS. FAILURE TO DO SO SHALL NOT RELIEVE CONTRACTOR OF CONTRACTUAL OBLIGATIONS NOR JUSTIFY ADDITIONAL COMPENSATION.
2. BEFORE STARTING ANY WORK, THE CONTRACTOR SHALL EXAMINE THE COMPLETE SET OF DRAWINGS FOR ALL TRADES, VERIFY ALL DIMENSIONS, SPACE REQUIREMENTS AND POINTS OF CONNECTION FOR ALL EQUIPMENT, MAKE MINOR ADJUSTMENTS NECESSARY TO AVOID CONFLICTS WITH EXISTING STRUCTURES AND THE WORK OF OTHER TRADES. CONTRACTOR SHALL VERIFY PURCHASED EQUIPMENT RATINGS AND DIMENSIONS MATCH DESIGN RATINGS AND DIMENSIONS PRIOR TO PURCHASE AND INSTALLATION. LAYOUT DIMENSIONS SHOWN ON THE DRAWINGS SHALL BE ADJUSTED BY CONTRACTOR TO ACCOMMODATE EQUIPMENT REQUIREMENTS OF INSTALLATION. CONTRACTOR SHALL OBTAIN MANUFACTURER'S SUBMITTALS FROM THE MANUFACTURER FOR CONTRACTOR PURCHASED EQUIPMENT AND FROM THE TERMO COMPANY FOR ALL OF THE TERMO COMPANY FURNISHED EQUIPMENT PRIOR TO LAYOUT AND INSTALLATION.
3. CONTRACTOR SHALL CONFINE SERVICE INTERRUPTION TO PERIODS SCHEDULED BY CONTRACTOR AND APPROVED BY THE CLIENT. ANY REQUIREMENTS FOR INTERRUPTION OR DISCONNECTION OF SERVICE SHALL BE REQUESTED IN WRITING FROM THE CLIENT PROJECT MANAGER AT LEAST 14 DAYS PRIOR TO SCHEDULED INTERRUPTION.
4. CONTRACTOR SHALL TAKE NECESSARY PRECAUTIONS TO PROTECT EXISTING AND NEW EQUIPMENT AND FACILITIES FROM DAMAGE DURING CONSTRUCTION.
5. CONTRACTOR SHALL SCHEDULE ALL REQUIRED INSPECTIONS. EACH INSPECTION SHALL BE COMPLETED BEFORE PROCEEDING WITH THE NEXT STAGE OF WORK. CONTRACTOR SHALL CORRECT, AT HIS OWN EXPENSE, ITEMS UNACCEPTABLE TO THE CLIENT OR CITY OF LONG BEACH.
6. ALL ELECTRICAL WORK SHALL BE IN ACCORDANCE WITH THE 2001 CALIFORNIA ELECTRICAL CODE (CEC), 2001 CALIFORNIA BUILDING CODE (CBC), ALL LOCAL CODES, ORDINANCES AND THE OCCUPATIONAL SAFETY HEALTH ACT (OSHA).
7. ALL ELECTRICAL MATERIALS SHALL BE NEW AND UNDERWRITERS LABORATORY (UL) LISTED AND RATED FOR THE INTENDED USE.
8. ALL LOW VOLTAGE CONDUCTORS SHALL BE STRANDED COPPER WITH 600V THWN/THWN INSULATION IN ACCORDANCE WITH DRAWINGS AND SPECIFICATIONS.
9. MINIMUM LOW VOLTAGE CONDUCTOR SIZE IS 12 AWG UNLESS OTHERWISE NOTED.
10. MINIMUM CONDUIT SIZE IS 3/4 INCH (1 INCH BELOW GRADE) UNLESS OTHERWISE NOTED.
11. THE DRAWINGS ARE DIAGRAMMATIC. CONDUIT ROUTING, CONDUIT BENDS, SUPPORT AND UNDEFINED DETAILS SHALL BE INSTALLED IN ACCORDANCE WITH CALIFORNIA ELECTRICAL CODE REQUIREMENTS AND SHALL BE DETERMINED BY CONTRACTOR AS A NECESSARY PART OF THE CONTRACTORS WORK.
12. INSTALLATION OF ELECTRICAL EQUIPMENT SHALL INCLUDE ALL MEASURES NECESSARY FOR SEISMIC ZONE 4 INCLUDING ANCHOR BOLTS AND CROSS BRACING WHERE REQUIRED. FOLLOW MANUFACTURER'S DETAILS AND INSTRUCTIONS FOR SEISMIC ZONE 4 INSTALLATION.
13. CONTRACTOR SHALL TEST ALL CIRCUIT ELEMENTS FOR INSULATION RESISTANCE PRIOR TO ENERGIZATION AND PERFORM ALL PRE-COMMISSION TESTING RECOMMENDED BY MANUFACTURERS. CONTRACTOR SHALL PROVIDE TEST RESULT DOCUMENTATION TO THE TERMO COMPANY.
14. MODIFICATIONS AND ADDITIONS TO EXISTING EQUIPMENT SHALL BE MADE IN A MANNER WHICH MAINTAINS THE ORIGINAL NRTL LISTING. WHERE LISTING IS COMPROMISED, THE CONTRACTOR SHALL PAY TO HAVE THE EQUIPMENT RE-CERTIFIED OR REPLACED.

REV. NO.	DESCRIPTION	CHK	DATE	REVISIONS	REV.	DATE	REVISIONS	CHK
					0	4/28/04	ISSUED FOR CONSTRUCTION	LKC / TMH
					A	4/02/04	ISSUED FOR PLAN CHECK	LKC / TMH
						3/22/04	ISSUED FOR CLIENT REVIEW	

THE TERMO COMPANY
3275 CHERRY AVENUE
LONG BEACH, CA 90801

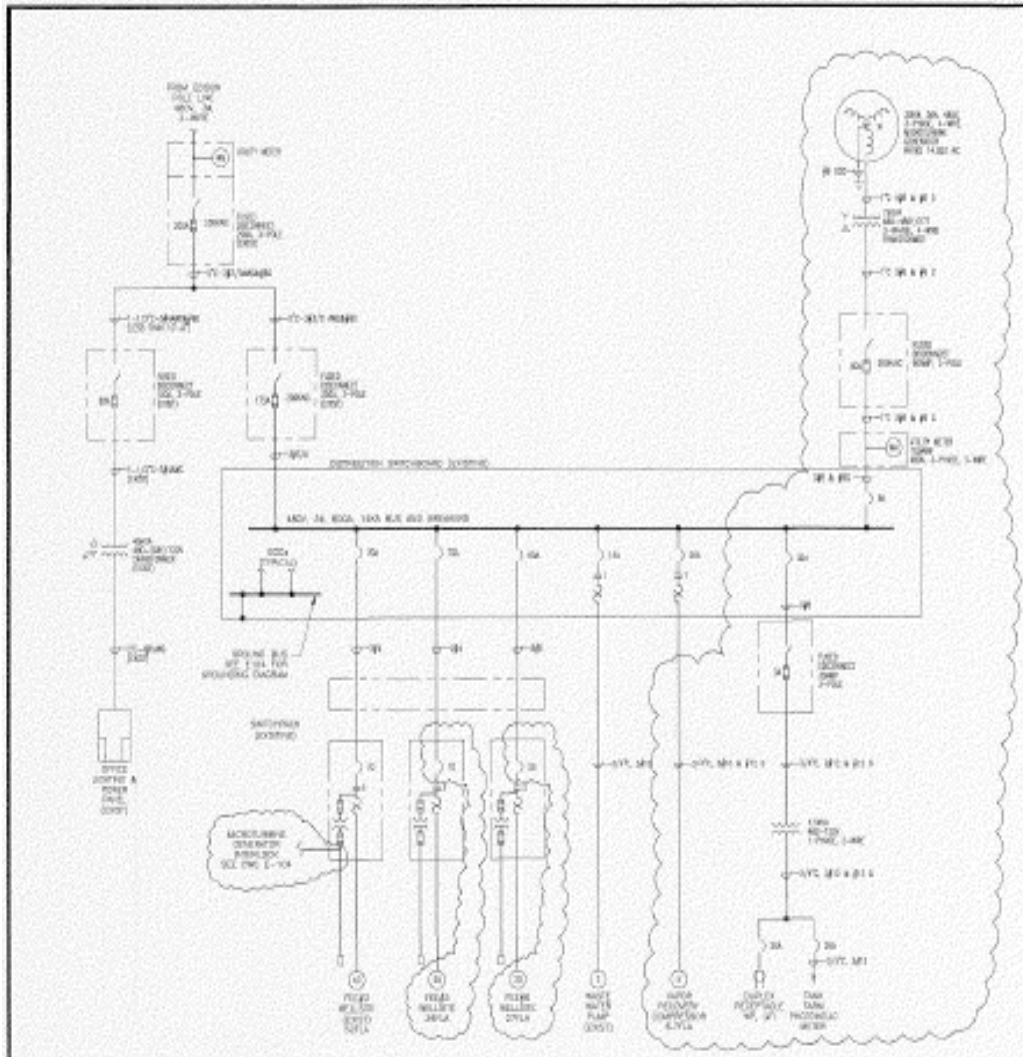
PROJECT ENGR.	DATE
LKC	03/22/04
DESIGNED	DATE
LKC	03/15/04
DRAWN	DATE
JPP	03/15/04
APPROVED	CHECK DATE

MICROTURBINE GENERATOR ADDITION
TITLE, INDEX & GENERAL NOTES

LONG BEACH CALIFORNIA

SCALE	SIZE	PROJECT NUMBER	DRAWING NUMBER	REV.
NONE	D	3134-04	D100	0

POWER ENGINEERING SERVICES
2703 SATURN STREET
BREA, CA 92821
TEL: 714-524-9100



LOAD CALCULATIONS

	AMPS
EXISTING LOAD (NOTE 1)	47.0 AMPS
VAPOR RECOVERY COMPRESSOR	4.7 AMPS
MICROTURBINE GENERATOR (NOTE 2)	0.0
RECEPTACLES (1.5 KVA TRANSFORMER)	3.0
FEEDS PUMP (NOTE 3)	34 FLA
FEEDS PUMP (NOTE 3)	27 FLA
FEEDS PUMP (NOTE 4)	0
TOTAL (WITHOUT MICROTURBINE)	117.7 AMPS
MICROTURBINE OPERATING	-38 AMPS
FEEDS PUMP (NOTE 4)	52 FLA
TOTAL (WITH MICROTURBINE)	133.7 AMPS

NOTES:

1. NEC 220-35 ALTERNATE METHOD IS USED TO DETERMINE EXISTING LOAD. HIGHEST PEAK DEMAND FROM SOUTHERN CALIFORNIA EDISON FOR THE LAST TWELVE MONTHS IS 31KW AT 80% PF = 37-AMPS. THE EDISON PEAK DEMAND IS MULTIPLIED BY 125% TO OBTAIN THE EXISTING LOAD FIGURE OF 47-AMPS USED IN THE CALCULATION.
2. THE CAPSTONE MODEL 330 MICROTURBINE GENERATOR USES OUTPUT FROM THE VAPOR RECOVERY COMPRESSOR TO SUPPLY ELECTRIC POWER. THE MICROTURBINE WILL PRODUCE A MAXIMUM OF 38-AMPS AT 480 VOLTS TO THE ELECTRICAL SYSTEM. FOR THE BASE CALCULATION NO LOAD IS ASSIGNED TO THIS DEVICE.
3. WELL PUMPS WERE NOT IN OPERATION DURING THE PREVIOUS YEAR AND ARE NOT PART OF THE EXISTING LOAD. MOTORS ARE REPLACED. MOTORS FOR FEEDS AND FEEDS ARE REDUCED IN SIZE AND BREAKERS & OVERLOAD HEATERS IN THE MOTOR STARTERS SIZED ACCORDINGLY.
4. AN ELECTRICAL INTERLOCK IS PROVIDED IN THE FEEDS PUMP STARTER TO PREVENT THE PUMP FROM RUNNING IF THE MICROTURBINE IS NOT IN OPERATION. ALSO, SHOULD THE MICROTURBINE FAIL PUMP FEEDS WOULD AUTOMATICALLY BE STOPPED.

NO.	DATE	DESCRIPTION	BY
B	1.20.04	ISSUED FOR CONSTRUCTION	DKC / TMH
B	4.02.04	ISSUED FOR PLAN CHECK	DKC / TMH
A	3.22.04	ISSUED FOR CLIENT REVIEW	

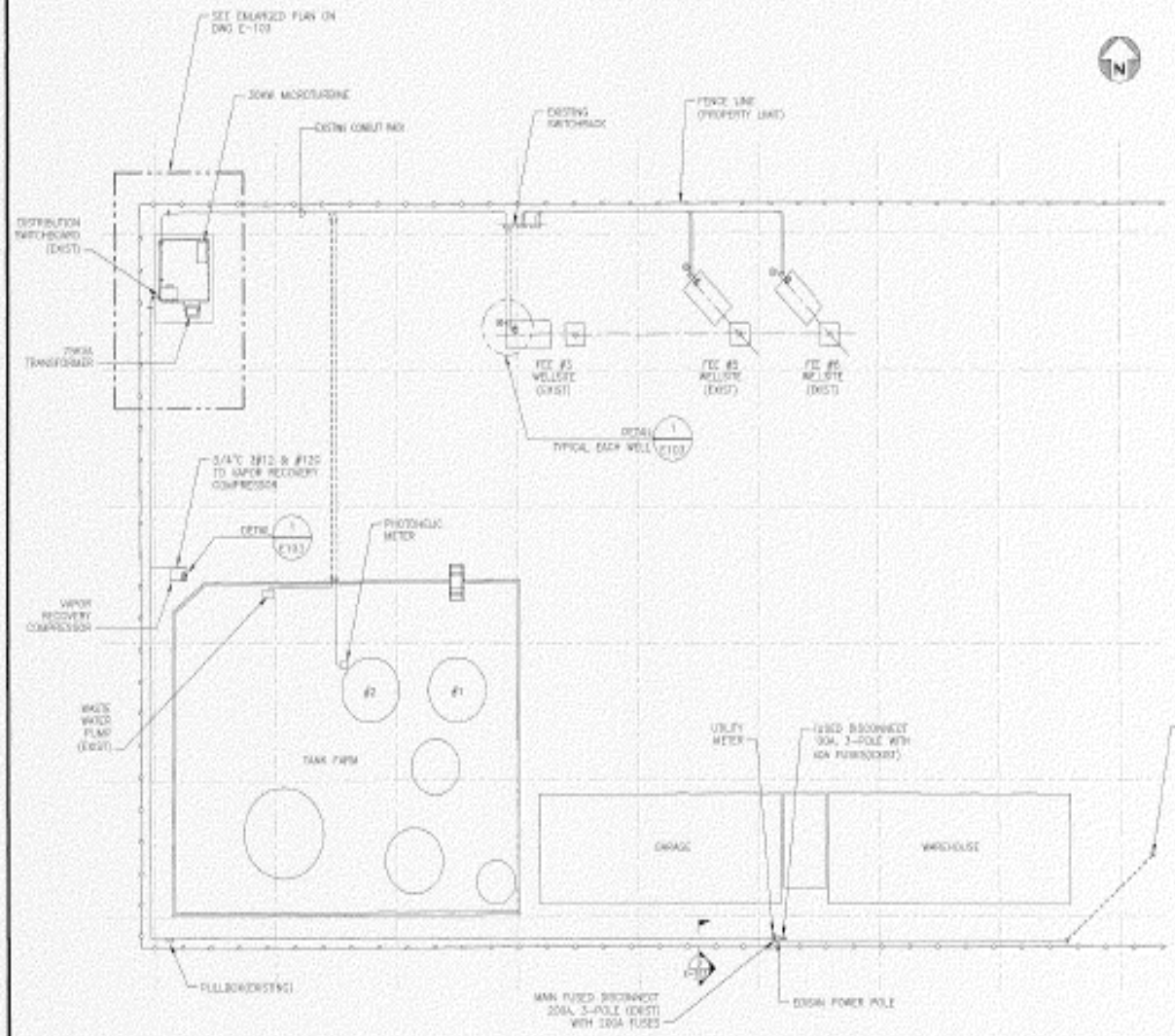
THE TERMO COMPANY
3275 CHERRY AVENUE
LONG BEACH, CA 90801

DRAWN	DKC	03.12.04
DESIGNED	DKC	03.15.04
CHECKED	JPP	03.16.04
APPROVED		

MICROTURBINE GENERATOR ADDITION SINGLE LINE DIAGRAM

LONG BEACH CALIFORNIA

DIST.	SUBSTATION	DRAWING NUMBER	SHEET	REV
PORG	D	2104-04	5101	0



AREA CLASSIFICATION NOTES

1. TANK FARM AREA IS CLASSIFIED AS CLASS 1, DIVISION 2, GROUP B, FOR 10'-0" FROM SHELL & ROOF OF TANKS AND SPACE INSIDE DIKE AREA TO THE TOP OF THE DIKE IN ACCORDANCE WITH CEC 515-2 FOR BULK STORAGE PLANTS.
2. WELLSITE AREAS ARE CLASSIFIED AS CLASS 1, DIVISION 2, GROUP D FOR 5'-0" AROUND THE WELLHEAD IN ALL DIRECTIONS AND 15'-0" HORIZONTALLY 1'-6" ABOVE GRADE. BELOW GRADE CELLARS LOCATED WITHIN THE CLASSIFIED AREA ARE CONSIDERED DIVISION 1 TO THE TOP OF THE CELLAR. WELLSITE AREA CLASSIFICATION IS IN ACCORDANCE WITH API-RP-500 SECTION 10.5.3.1 FOR BEAM PUMPING WELLS.
3. THE NEW VAPOR RECOVERY COMPRESSOR IS CLASSIFIED AS CLASS 1, DIVISION 2, GROUP D FOR 25' AROUND THE COMPRESSOR IN ACCORDANCE WITH API-RP-500 SECTION 0.5.5.
4. AREAS NOT LISTED ABOVE ARE CONSIDERED AS UNCLASSIFIED FOR THE PURPOSE OF THIS PROJECT.
5. ALL WIRING AND EQUIPMENT IN CLASS 1, DIVISION 1 AND 2 LOCATIONS SHALL BE GROUNDED IN ACCORDANCE WITH CEC 501-16.
6. SEAL ALL CONDUITS CROSSING AREA CLASSIFICATION BOUNDARIES IN ACCORDANCE WITH CEC 501-5(b).

REVISION NO.	DESCRIPTION	REV.	DATE	DRAWING	NO.	DATE	DESCRIPTION	
					1			
					2			
					3			
					4	4/29/04	ISSUED FOR CONSTRUCTION	
					5	4/02/04	ISSUED FOR PLAN CHECK	
					6	3/22/04	ISSUED FOR CLIENT REVIEW	
					7			
					8			

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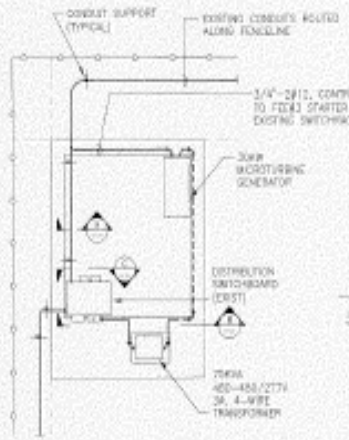
3275 CHERRY AVENUE
LONG BEACH, CA 90801

DRAWN BY	UKC	03/12/04
REVIEWED BY		DATE
CHECKED BY	UKC	03/15/04
APPROVED BY		DATE
PROJECT ENGINEER	JPP	03/16/04

MICROTURBINE GENERATOR ADDITION POWER PLAN

LONG BEACH CALIFORNIA

PROJECT NO.	SHEET	PROJECT NAME	PROJECT NUMBER	REV.
10210	D	3326-04	0102	D

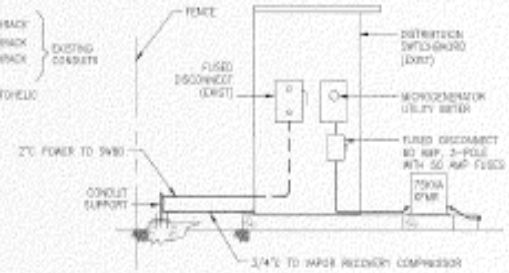


ENLARGED PLAN

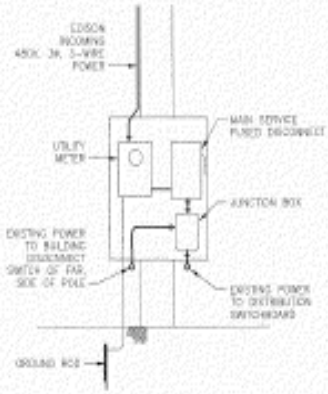
SCALE: 1/4"=1'-0"

CONDUIT SUPPORT (A)

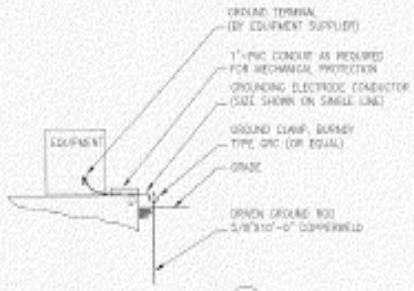
N.T.S.



SECTION (B)

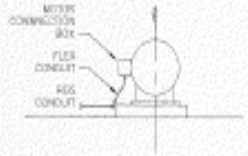


SECTION (D) E-102



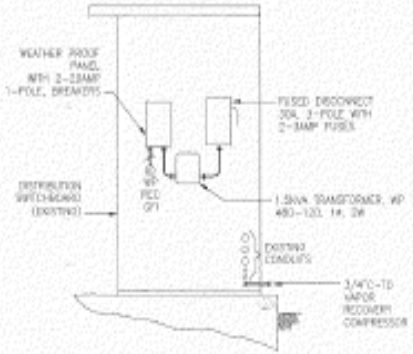
GROUND ROD INSTALLATION DETAIL (Z) E-104

N.T.S.



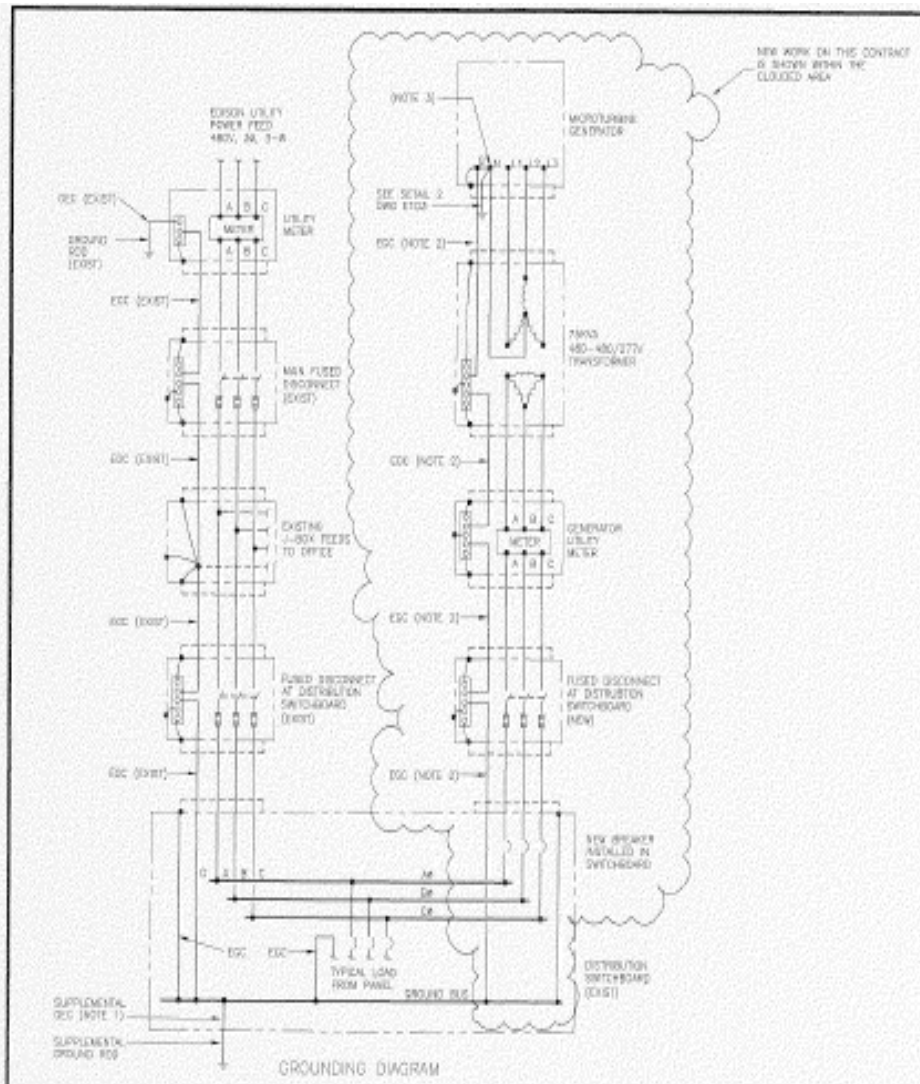
MOTOR CONNECTION DETAIL (T) E-102

N.T.S.



SECTION (C)

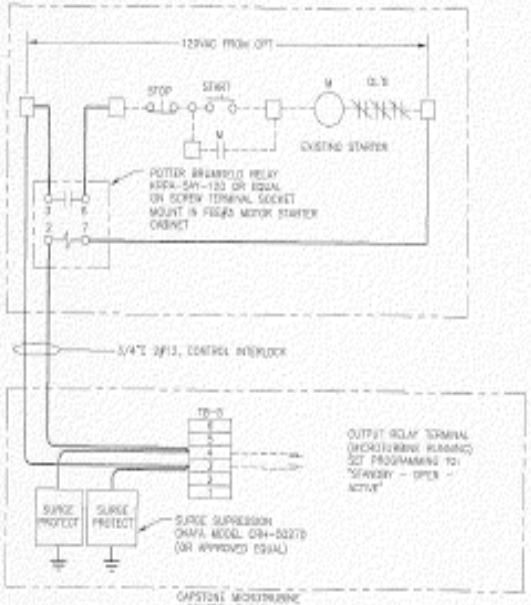
REVISIONS								



GROUNDING DIAGRAM

GROUNDING NOTES

1. (GEC) GROUNDING ELECTRODE CONDUCTOR SIZED IN ACCORDANCE WITH CEC TABLE 250-66.
2. (EGC) EQUIPMENT GROUNDING CONDUCTOR SIZE IN ACCORDANCE WITH CEC TABLE 250-122. SEE DRAWING E1.01 FOR EGC SIZES.
3. THE MICROTURBINE IS DESIGNED FOR GROUND-REFERENCED, BALANCED PHASE-TO-NEUTRAL OPERATION AND MUST BE CONNECTED TO A 4-WIRE WYE CIRCUIT. THE 75 KVA TRANSFORMER IS PROVIDED FOR THIS PURPOSE. AN EARTH GROUND AT THE MICROTURBINE IS ALWAYS REQUIRED.



MICROTURBINE/WELL PUMP CONTROL INTERLOCK DIAGRAM
PREVENTS WELL PUMP FROM RUNNING WHEN MICROTURBINE IS NOT OPERATING, AND STOPS WELL PUMP ON LOSS OF MICROTURBINE GENERATOR

REVISION NO.	DESCRIPTION	BY	DATE	DESCRIPTION	NO.	DATE	REVISIONS	BY
					D	4/18/04	ISSUED FOR CONSTRUCTION	LKC
					B	4/02/04	ISSUED FOR PLAN CHECK	TMH
					A	3/22/04	ISSUED FOR CLIENT REVIEW	LKC / TMH

THE TERMO COMPANY
3275 CHERRY AVENUE
LONG BEACH, CA 90801

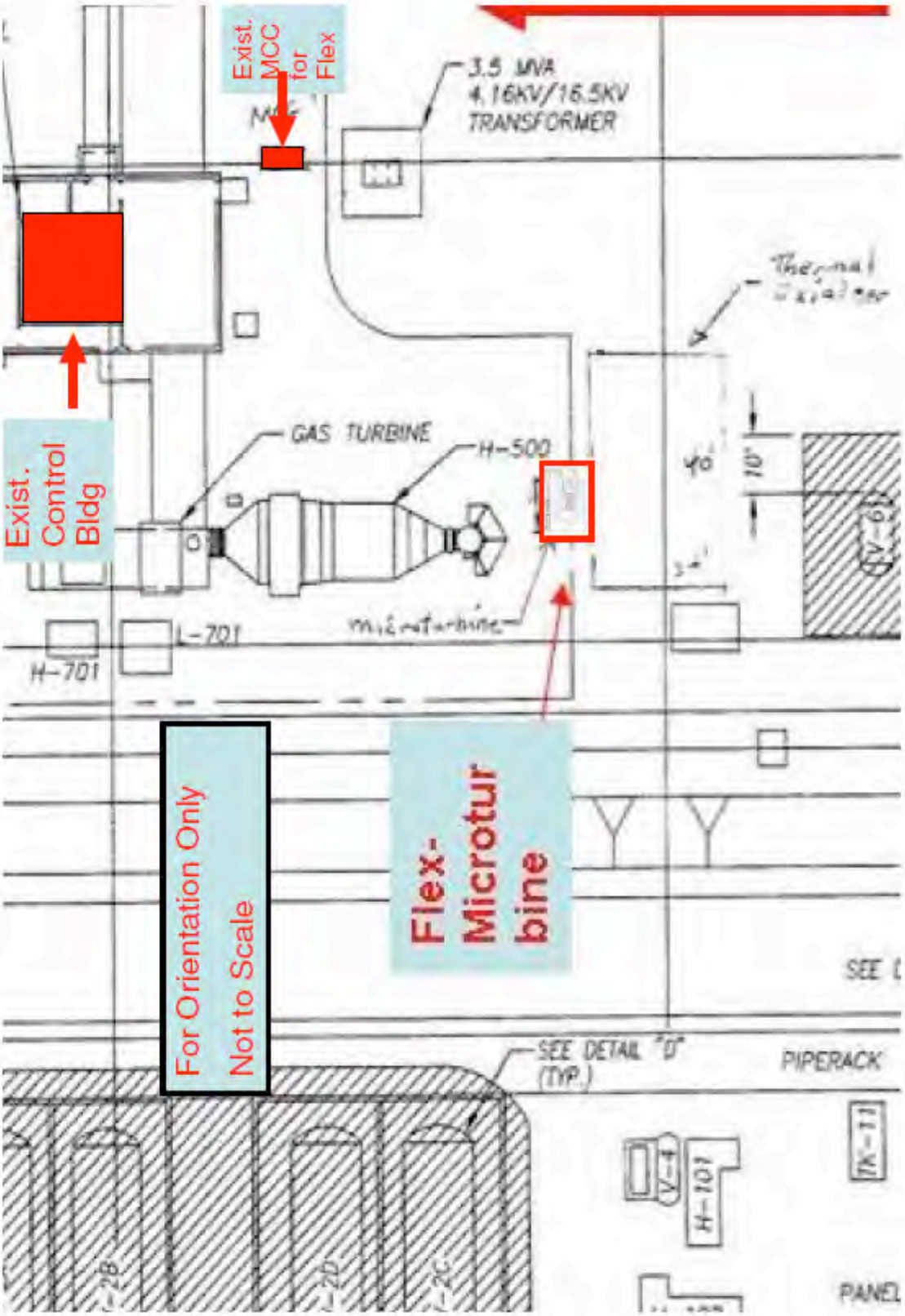
DRAWN BY	DATE
LKC	02/12/04
CHECKED BY	DATE
LKC	02/13/04
ISSUED BY	DATE
JPP	02/16/04
DESIGNED BY	DATE

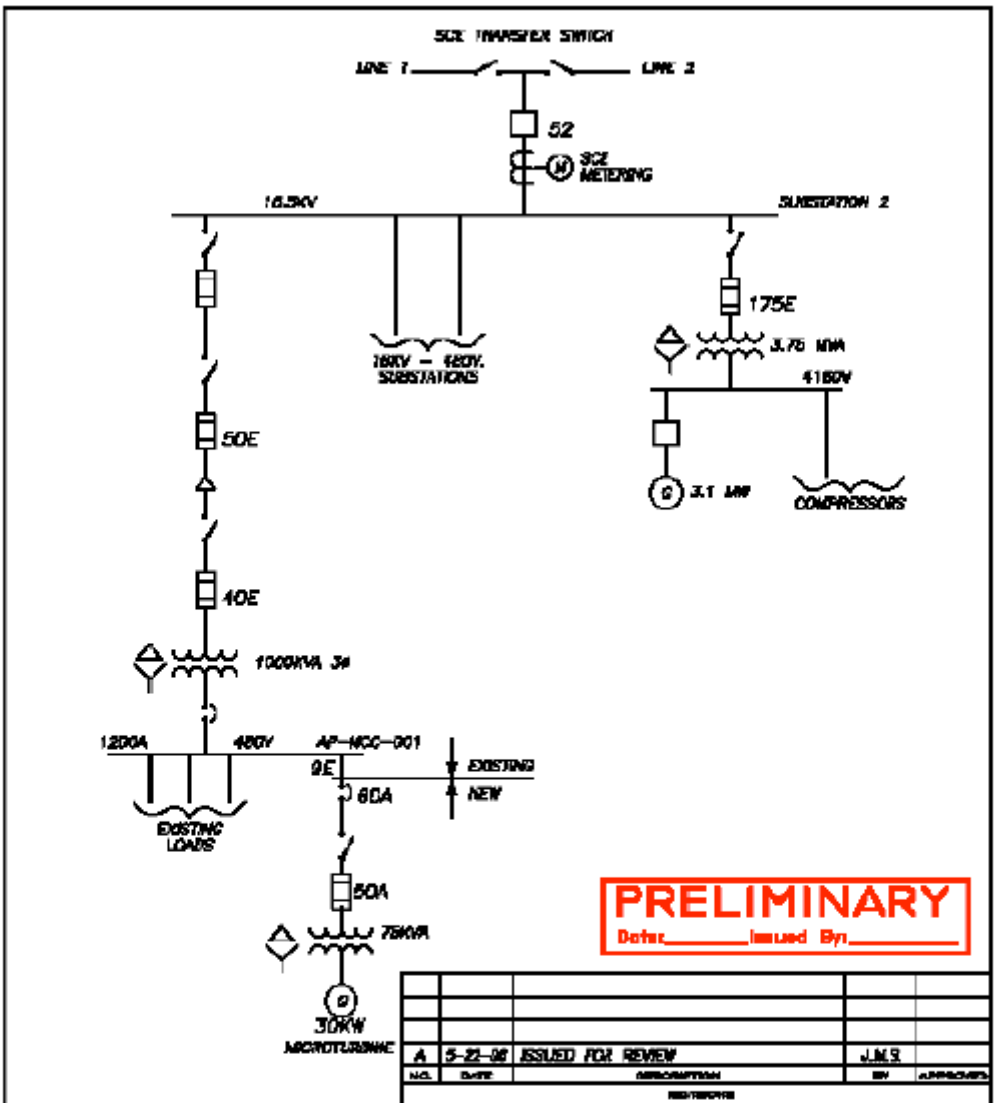
MICROTURBINE GENERATOR ADDITION
GROUNDING AND INTERLOCK DIAGRAMS
LONG BEACH CALIFORNIA

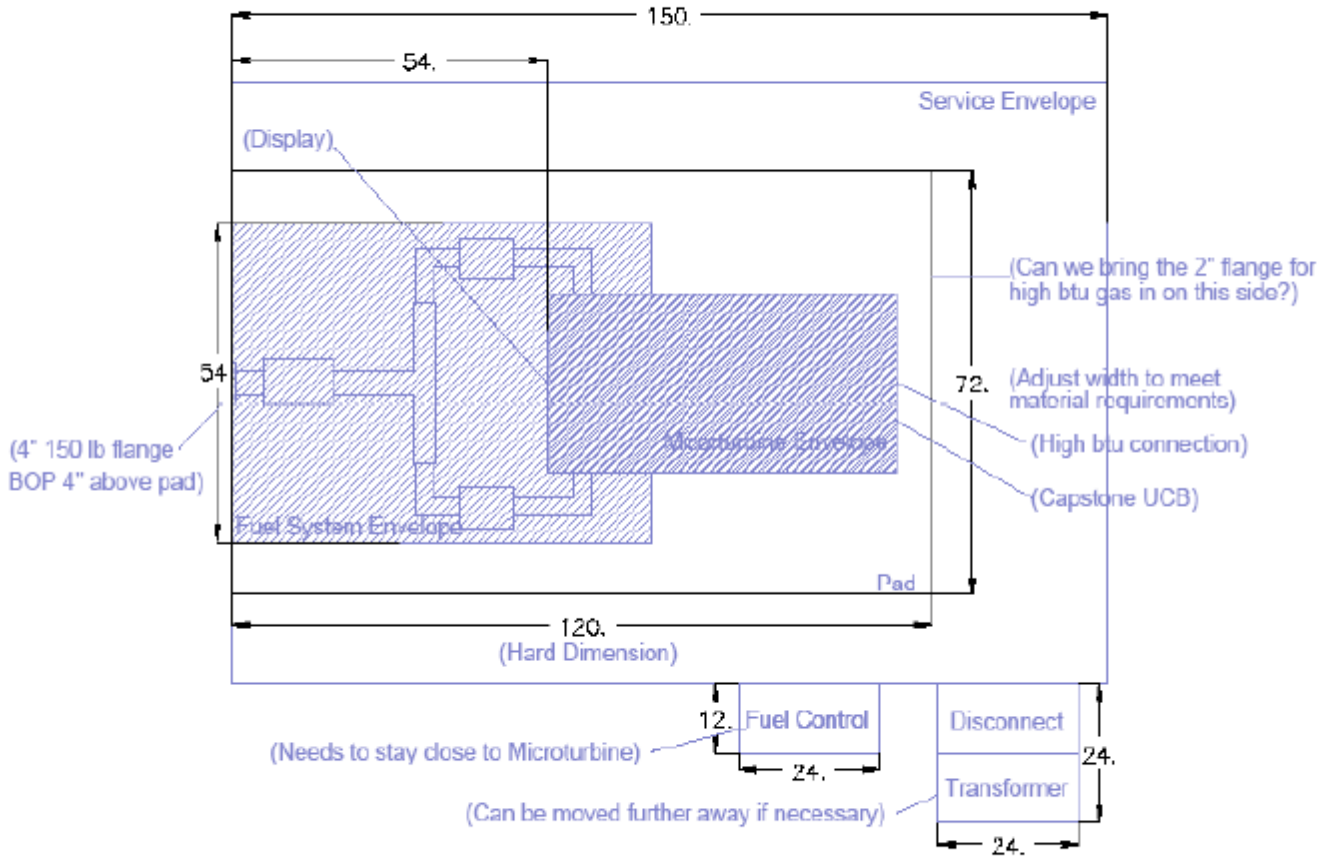
SCALE	SIZE	PROJECT NUMBER	FILENAME	REV.
NONE	D	2004-04	E100	D

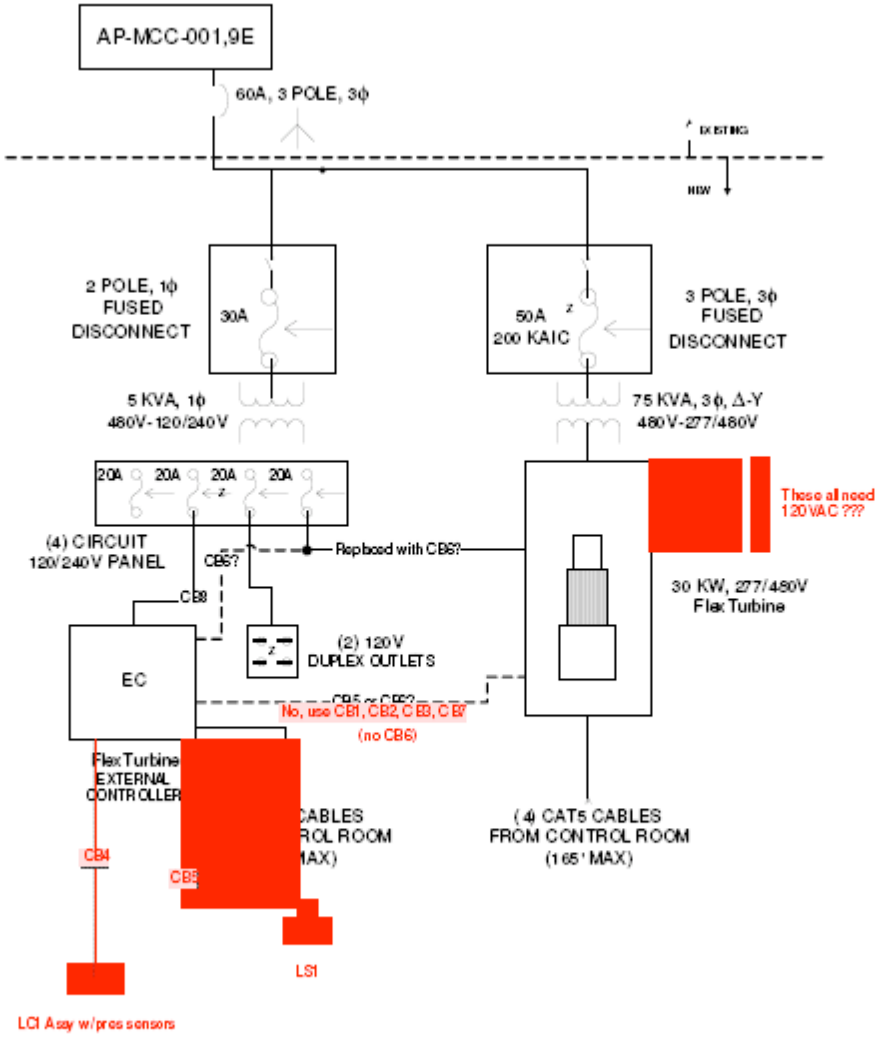
PETERSON PRIEST
ENGINEERS

LOW BTU
SITE DRAWINGS

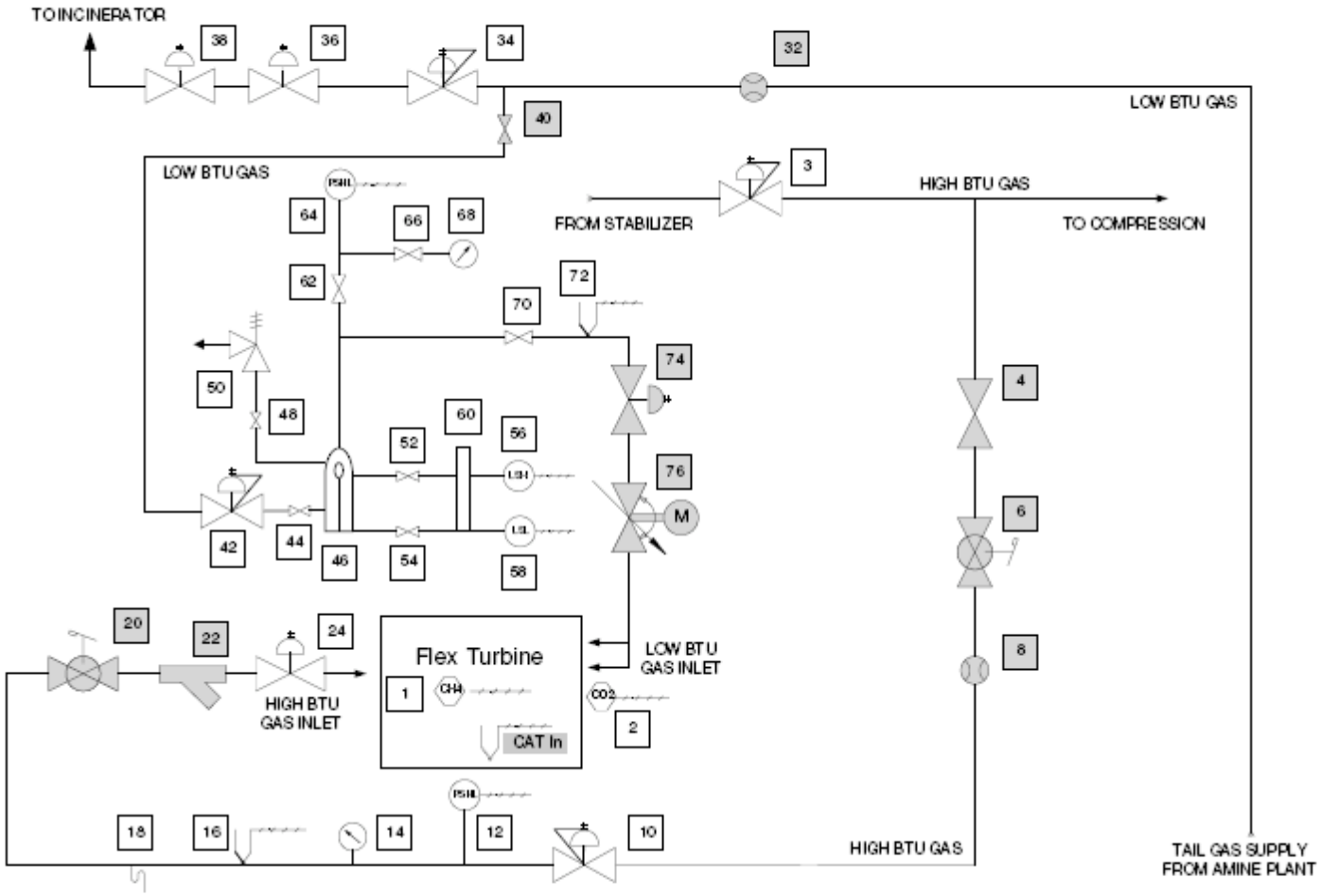

Exist. MCC for Flex
3.5 MVA
4.16KV/16.5KV
TRANSFORMER
Thermal
GAS TURBINE
H-500
Exist. Control Bldg
40'
10'
L-701
H-701
microturbine
For Orientation Only
Not to Scale
Flex-Microturbine
SEE DETAIL "D"
(TYP.)
PIPERACK
V-4
H-101
TK-11
PANEL


SCE TRANSFER SWITCH
LINE 1
LINE 2
52
SCE METERING
16.5KV
SUBSTATION 2
175E
3.75 MVA
4160V
3.1 MW
COMPRESSORS
16KV – 120V. SUBSTATIONS
50E
40E
1000KVA 3Ø
1200A
480V
AP-MCC-001
9E
EXISTING
NEW
60A
EXISTING LOADS
50A
75KVA
30KW
MICROTURBINE
PRELIMINARY
Date_____Issued By_____
A
5-22-06
ISSUED FOR REVIEW
J.M.S.
NO.
DATE
DESCRIPTION
BY
APPROVED
REVISIONS
COPE
California Oil Producers
Electric Cooperative
COPE OFFGASES PROJECT
DECOR RINCON FACILITY – VENTURA COUNTY
DRAWN BY J.M.S.
APPROVED BY
DRAWING NUMBER
REV. NO.
DATE 5/22/06
SCALE NONE
COPE009
A


150.
54.
Service Envelope
(Display)
(Can we bring the 2" flange for high btu gas in on this side?)
54
72.
(Adjust width to meet material requirements)
(4" 150 lb flange BOP 4" above pad)
Microturbine Envelope
(High btu connection)
(Capstone UCB)
Fuel System Envelope
Pad
120.
(Hard Dimension)
12.
Fuel Control
Disconnect
(Needs to stay close to Microturbine)
24.
24.
Transformer
(Can be moved further away if necessary)
24.



ROSF FlexTurbine ELECTRICAL PANEL
ONE-LINE SCHEMATIC



R.O.S.F. FlexTurbine Plumbing Schematic

9.13.06

Existing or already obtained

MEDIUM BTU
SITE DRAWINGS

ELECTRICAL NOTES:

1. **DEFINITIONS**

"FURNISH" MEANS TO "SUPPLY" AND USUALLY REFERS TO DELIVERY OF AN ITEM OF EQUIPMENT TO THE PROJECT SITE, READY FOR INSTALLATION.

"INSTALL" MEANS TO SET IN PLACE, CONNECT AND PLACE IN FULL OPERATIONAL ORDER.

"PROVIDE" MEANS TO "FURNISH" AND "INSTALL".

"EQUIVALENT" MEANS TO MEET THE SPECIFICATIONS OF THE REFERENCED PRODUCT OR ITEM ON ALL SIGNIFICANT ASPECTS, WHERE SIGNIFICANT ASPECTS SHALL BE DETERMINED BY THE ENGINEER.

"FUTURE", "BY OTHERS", "REFER (DISCIPLINE) DIVISION" AND SIMILAR EXPRESSIONS INDICATE WORK THAT MAY BE PERFORMED UNDER THE CONTRACT DOCUMENTS BUT NOT NECESSARILY UNDER THE DIVISION OR DISCIPLINE ON WHICH THE NOTE APPEARS. THE CONTRACTOR SHALL BE RESPONSIBLE FOR COORDINATING THE WORK WITH SUPPLIERS, SUBCONTRACTORS, EMPLOYEES, ETC. SHOULD CLARIFICATION OF ANY PORTION OF THE WORK BE REQUIRED, CONTACT THE ARCHITECT/ENGINEER PRIOR TO SUBMITTING BID.

2. **CODES**

THE WORK SHALL COMPLY WITH ALL APPLICABLE LOCAL, MUNICIPAL, AND NATIONAL CODES. THIS WOULD INCLUDE, BUT IS NOT LIMITED TO, THE CURRENT CITY BUILDING CODE, NFPA, ANSI, OSHA, AND ALL OTHER LOCAL OR MUNICIPAL BUREAUS AND DEPARTMENTS WHICH HAVE AUTHORITY OVER THE PROJECT. ANYTHING IN THESE CONTRACT DOCUMENTS NOT WITHSTANDING, THIS SHALL NOT BE CONSTRUED AS WAIVING COMPLIANCE WITH ANY REQUIREMENTS OF THE PLANS AND SPECIFICATIONS WHICH MAY BE IN EXCESS OF ANY REQUIREMENTS OF THESE CODES.

3. **INTERPRETATION OF THE DOCUMENTS**

THE CONTRACTOR SHALL CAREFULLY COMPARE THE DRAWINGS AND SPECIFICATIONS, CHECKING THE MEASUREMENTS AND CONDITIONS UNDER WHICH CONSTRUCTION IS TO BE IMPLEMENTED. FOR CLARIFICATION BETWEEN VARIOUS DRAWINGS AND/OR SPECIFICATIONS, THE DISPUTED ISSUE SHALL BE REFERRED TO THE ENGINEER BEFORE ANY WORK IS EXECUTED. THE CONTRACTOR SHALL STATE IN THEIR PROPOSAL ANY EXCEPTIONS NECESSARY TO MAKE THIS WORK A COMPLETE AND READY-TO-USE INSTALLATION. IF NOT SO STATED IN THE CONTRACTOR'S PROPOSAL, ANY SUCH WORK WILL NOT BE CONSIDERED ADDITIONAL.

4. **COORDINATION**

THE ELECTRICAL DRAWINGS ARE DIAGRAMMATIC IN NATURE AND SHALL NOT BE SCALED. TO THIS EXTENT, DATA GIVEN ON THE DRAWINGS IS AS EXACT AS COULD BE SECURED. THE CONTRACTOR SHALL COORDINATE THE EXACT LOCATION OF ALL REQUIRED WORK AND EQUIPMENT WITH THAT OF THE OTHER TRADES. WHERE THERE ARE POTENTIAL CONFLICTS, THE CONTRACTOR SHALL OBTAIN AND VERIFY EXACT LOCATIONS, MEASUREMENTS, LEVELS, SPACE REQUIREMENTS, ETC. AT THE SITE AND SHALL SATISFACTORILY ADAPT HIS WORK TO ACTUAL FIELD CONDITIONS.

REFER TO ARCHITECTURAL/MECHANICAL DRAWINGS FOR PLANS, ELEVATIONS AND DETAILS INDICATING THE LOCATIONS OF CEILING ELEMENTS (E.G., LIGHTS, SPRINKLERS, DIFFUSERS, ETC.) AND WALL ELEMENTS. CEILING MOUNTED ITEMS SHALL BE INSTALLED IN ACCORDANCE WITH THE ARCHITECTURAL REFLECTIVE CEILING PLANS. IF LOCATION FOR AN ITEM IS NOT SHOWN ON THE ARCHITECTURAL DRAWINGS, VERIFY THE EXACT LOCATION OF THE ITEM WITH THE ARCHITECT PRIOR TO INSTALLATION. THESE REQUIREMENTS APPLY TO ALL CEILING TYPES IN ALL AREAS.

5. **SITE EXAMINATION**

THE CONTRACTOR SHALL VISIT THE SITE, EXAMINE THE PREMISES, AND MAKE A THOROUGH SURVEY OF THE CONDITIONS UNDER WHICH CONSTRUCTION WILL BE IMPLEMENTED. THE SUBMISSION OF A PROPOSAL WILL BE CONSTRUED AS EVIDENCE THAT SUCH AN EXAMINATION HAS BEEN MADE AND ANY LATER CLAIMS FOR LABOR, EQUIPMENT, OR MATERIALS REQUIRED FOR DIFFICULTIES ENCOUNTERED WHICH COULD HAVE BEEN FORESEEN HAD SUCH AN EXAMINATION BEEN MADE, WILL NOT BE RECOGNIZED.

6. **PERMITS**

THE CONTRACTOR SHALL OBTAIN AND PAY FOR ALL PERMITS, INSPECTIONS, AND FEES REQUIRED FOR THE EXECUTION OF THIS WORK. SCHEDULING OF ALL REQUIRED INSPECTIONS SHALL BE THE RESPONSIBILITY OF THE CONTRACTOR.

7. **SAFETY**

THE CONTRACTOR SHALL TAKE ALL STEPS NECESSARY TO ENSURE THE SAFETY OF THE CLIENT'S EMPLOYEES, BUILDING EMPLOYEES AND GUESTS AS WELL AS THEIR OWN FORCES, BY ADEQUATELY PROTECTING ANY EXPOSED LIVE CABLE, EQUIPMENT, OR DEVICES THROUGHOUT THE COURSE OF THIS WORK.

8. **FIRESAFING**

ALL PENETRATIONS IN WALLS, FLOORS, OR CEILINGS SHALL BE SUITABLY CLOSED UP AND SEALED WITH A FIRESAFING COMPOUND LISTED IN THE MOST RECENT FACTORY MUTUAL RESEARCH CORPORATION (FMRC) APPROVAL GUIDE. PRODUCTS SIMILAR TO THOSE MANUFACTURED BY 3M ARE PREFERRED.

9. **TEMPORARY POWER AND LIGHTING**

THE CONTRACTOR SHALL PROVIDE TEMPORARY POWER AND LIGHTING FOR THIS WORK DURING CONSTRUCTION. TEMPORARY LIGHTING SHALL AT LEAST BE THE EQUAL OF (1)100-WATT FIXTURE EVERY 100 SQUARE FEET, WITH A MINIMUM ONE FIXTURE PER ROOM. TEMPORARY LIGHTING SHALL BE LEFT IN PLACE UNTIL PERMANENT LIGHTING IS COMPLETELY OPERATIONAL. COORDINATE TEMPORARY POWER REQUIREMENTS WITH THE OTHER TRADES AND PROVIDE ADEQUATE PROVISIONS. THE CONTRACTOR SHALL PERFORM ALL COORDINATION WITH THE OWNER AND/OR LANDLORD.

10. **CABLING**

UNLESS SPECIFICALLY NOTED OTHERWISE IN THE PLANS, ALL CABLING SHALL BE (2) #12 AND (1) #12 G IN 3/4" C.

11. **CABLE SIZING**

BRANCH CIRCUIT CABLE SIZE SHALL BE ADJUSTED BASED ON THE CONDUCTOR LENGTH AS INDICATED BELOW.

A. 120/208V CABLING FROM PANEL TO ELECTRICAL LOAD SHALL BE AS FOLLOWS UNLESS OTHERWISE INDICATED:

LESS THAN 100 FEET, USE #12 AWG MINIMUM
FROM 100 TO 200 FEET, USE #10 AWG MINIMUM
FROM 200 TO 350 FEET, USE #8 AWG MINIMUM

B. 277/480V CABLING FROM PANEL TO ELECTRICAL LOAD SHALL BE AS FOLLOWS UNLESS OTHERWISE INDICATED:

FROM 0 TO 150 FEET, USE #12 AWG MINIMUM
FROM 150 TO 250 FEET, USE #10 AWG MINIMUM
FROM 250 TO 350 FEET, USE #8 AWG MINIMUM

12. **CONDUIT/RACEWAY SYSTEMS**

THE CONDUIT ROUTINGS INDICATED ARE ONLY DIAGRAMMATIC IN NATURE. FIELD CONDITIONS SHALL DICTATE THE CONTRACTOR'S EXACT CONDUIT ROUTING. THE CONTRACTOR SHALL BE RESPONSIBLE FOR SIZING AND LOCATING PULL BOXES PER THE NEC AND FOR COORDINATION WITH OTHER DISCIPLINES. ALL EXPOSED RACEWAYS SHALL BE INSTALLED PARALLEL OR PERPENDICULAR TO WALLS OR STRUCTURAL MEMBERS, SUCH AS TO FOLLOW STRUCTURAL SURFACE CONTOURS AND NOT OBSTRUCT PASSAGEWAYS. MULTIPLE RACEWAY SHALL BE RUN TOGETHER IN GROUPING. ALL EXPOSED CONDUIT SHALL BE ROUTED PERPENDICULAR, PARALLEL AND TIGHT TO CEILINGS AND BEAMS. ALL EXPOSED CONDUIT SHALL BE COORDINATED WITH THE ARCHITECT/ENGINEER PRIOR TO INSTALLATION. EXTRA TIME SHOULD BE ALLOWED FOR THIS REVIEW AND APPROVAL. NO ADDITIONAL COST TO OWNER WILL BE ALLOWED DUE TO LACK OF COORDINATION.

EMERGENCY SYSTEMS SHALL BE RUN IN SEPARATE RACEWAY/CONDUIT SYSTEMS.

A SEPARATE INSULATED EQUIPMENT GROUNDING CONDUCTOR SHALL BE PULLED WITH THE CIRCUIT CONDUCTORS, WHETHER OR NOT INDICATED ON THE DRAWINGS. METAL RACEWAY OR CABLE ARMOR/SHEATH SHALL NOT BE USED AS THE PRIMARY EQUIPMENT GROUNDING CONDUCTOR. RACEWAY SYSTEMS SHALL BE MECHANICALLY AND ELECTRICALLY CONTINUOUS AND SHALL BE BONDED AT ALL POINTS TO THE INSULATED EQUIPMENT GROUNDING CONDUCTOR IN ACCORDANCE WITH THE APPLICABLE PROVISIONS IN ARTICLE 250 OF THE NEC.

REFER TO THE ARCHITECTURAL DRAWINGS FOR PAINTING OF RACEWAY.

13. **PAINTING**

ALL NEWLY INSTALLED RACEWAY SHALL BE PAINTED TO MATCH THE ADJACENT WALL OR CEILING SURFACE, UNLESS NOTED OTHERWISE PER THE ARCHITECTURAL PLANS OR SPECIFICATIONS.

14. **LIGHTING**

UNLESS NOTED OTHERWISE, THE LIGHT SWITCH LOCATED IN A ROOM SHALL CONTROL ALL THE LIGHTING FIXTURES IN THAT ROOM. LIGHTING FIXTURES SCHEDULED FOR EQUIPMENT AREAS SHALL BE INSTALLED AFTER ALL MAJOR PIECES OF MECHANICAL EQUIPMENT ARE IN PLACE. ARRANGE LIGHTING FIXTURES TO PROVIDE ADEQUATE ILLUMINATION OF CONTROLS, RACKS, ETC.

15. **EQUIPMENT**

ALL MATERIALS AND EQUIPMENT PROVIDED IN THIS WORK SHALL BE NEW AND SHALL HAVE THE APPROPRIATE UL LISTING AND/OR FM APPROVAL.

16. **RECEPTACLES**

UNLESS SPECIFICALLY NOTED OTHERWISE IN THE PLANS, ALL RECEPTACLE CABLING SHALL BE (2) #12 AND (1) #12 G IN 3/4" C.

17. **PANELBOARDS**

ALL PANELBOARDS IN WHICH WORK OCCURS PER THESE DOCUMENTS SHALL BE PROVIDED WITH UPDATED-TYPEWRITTEN DIRECTORIES. FROM FLUSH-MOUNTED PANELBOARDS, STUB-OUT ONE 3/4" CONDUIT INTO THE CEILING CAVITY FOR EACH SET OF 3 SPARES AND/OR SPACES OR FRACTION THEREOF OTHER SET.

18. **EQUIPMENT CONNECTIONS**

PROVIDE FINAL CONNECTIONS FOR ALL EQUIPMENT FURNISHED UNDER OTHER DIVISIONS OF THIS CONTRACT. PROVIDE A FLEXIBLE CONNECTION TO ALL VIBRATION PRODUCING EQUIPMENT.

19. **MECHANICAL EQUIPMENT**

ALL MECHANICAL EQUIPMENT WILL BE INSTALLED BY THE DIVISION 15 CONTRACTOR. COORDINATE THE EXACT LOCATION AND NATURE OF ANY REQUIRED ELECTRICAL CONNECTION TO BE PROVIDED FOR MECHANICAL EQUIPMENT PRIOR TO ROUGH-IN.

VERIFY THE ELECTRICAL SERVICE REQUIRED FOR EACH ITEM OF MECHANICAL EQUIPMENT WITH THE MECHANICAL CONTRACTOR PRIOR TO FURNISHING SUCH POWER. REFER MECHANICAL DRAWING FOR MECHANICAL EQUIPMENT REQUIRING ELECTRICAL CONNECTIONS. MAKE CONNECTION AND PROVIDE APPROPRIATE WIRE, CONDUIT AND OVERCURRENT PROTECTION FOR EQUIPMENT.

REFER TO MECHANICAL DRAWINGS FOR MOTORS THAT ARE TO BE INTERLOCKED.

THE DISCONNECTING MEANS FOR ALL MECHANICAL EQUIPMENT SHALL BE ACCESSIBLE AND HAVE CLEARANCES AS REQUIRED BY THE NEC.

20. **MISCELLANEOUS SUPPORTING MEMBERS**

ALL ANGLES, CHANNELS, AND OTHER MISCELLANEOUS STEEL, BOLTS, THREADED RODS, ETC. REQUIRED TO SUPPORT LIGHT FIXTURES, LADDER, TRAY OR OTHER ELECTRICAL EQUIPMENT OR DEVICES SHALL BE FURNISHED AND INSTALLED BY THE CONTRACTOR. ALL THREADED RODS SHALL BE A MINIMUM OF 5/8" IN DIAMETER.

21. **INTERFERENCE WITH OCCUPANCY**

WHERE THE BUILDING IS OCCUPIED AND SHALL CONTINUE TO BE BOTH OCCUPIED AND FULLY FUNCTIONAL DURING THE IMPLEMENTATION OF THIS WORK, IT IS IMPERATIVE THAT THE WORK COVERED BY THESE DOCUMENTS BE EXECUTED WITH A MINIMUM OF INCONVENIENCE TO BUILDING PERSONNEL AND FUNCTION.

22. **ELECTRICAL SERVICE DISRUPTIONS**

ANY WORK INVOLVING A TASK WHICH EXPOSES ACTIVE BUS SHALL BE PERFORMED DURING THE OWNER'S DESIGNATED MAINTENANCE HOURS (TYPICALLY 12:00 AM TO 6:00 AM LOCAL TIME). THIS RESTRICTION INCLUDES REMOVING THE COVER FROM ANY PANEL BOARD, SWITCHBOARD, MCC ETC. ALL WORK WHICH EXPOSES ACTIVE BUS SHALL REQUIRE A MOP (METHOD OF PROCEDURE) TO BE FILED WITH THE OWNER. THIS MOP SHALL BE WRITTEN BY THE CONTRACTOR IN COORDINATION WITH THE OWNER, AND MUST BE APPROVED BY THE OWNER PRIOR TO THE COMMENCEMENT OF SUCH WORK. THE CONTRACTOR SHALL PROVIDE A MINIMUM OF 7 DAYS NOTICE TO THE OWNER FOR WORK REQUIRING A MOP. ANY WORK WHICH REQUIRES AN ELECTRICAL SERVICE DISRUPTION, IN ADDITION TO REQUIRING AN MOP, SHALL BE CLOSELY COORDINATED WITH THE OWNER. ALL DISRUPTION SHALL OCCUR AT TIMES AND OF DURATIONS ACCEPTABLE TO THE OWNER. THE CONTRACTOR SHOULD ANTICIPATE THAT THERE ARE GOING TO BE BLOCKS OF TIME DURING WHICH THE OWNER WILL NOT ALLOW SERVICE DISRUPTIONS. THE OWNER WILL PROVIDE THE CONTRACTOR WITH THESE DATES AS THEY BECOME AVAILABLE.

23. **WORK NEAR ACTIVE EQUIPMENT**

ANY WORK NEAR ACTIVE COMMUNICATIONS EQUIPMENT SHALL BE DONE DURING THE OWNER'S DESIGNATED MAINTENANCE HOURS (TYPICALLY 12:00 AM TO 6:00 AM LOCAL TIME). THE CONTRACTOR SHALL PROTECT THE COMMUNICATIONS EQUIPMENT PER THE OWNER'S LATEST STANDARDS AND TO THE SATISFACTION OF THE OWNER'S CONSTRUCTION ENGINEER. EQUIPMENT PROTECTION WHICH IS TO REMAIN IN PLACE FOR MORE THAN 24 HOURS SHALL BE CONSTRUCTED IN SUCH A WAY AS TO ALLOW ACCESS TO THE EQUIPMENT AS WELL AS ACCOMMODATE EQUIPMENT VENTILATION REQUIREMENTS.

24. **DEMOLITION, RELOCATION AND ALTERATION**

PROVIDE REMOVAL, RELOCATION, REROUTING AND RECONNECTION OF EXISTING ELECTRICAL SYSTEMS, AS REQUIRED TO ACCOMPLISH ALTERATION, RESTORATION AND NEW WORK. VERIFY THAT ALL REUSED EQUIPMENT IS IN GOOD WORKING ORDER.

ALL MATERIAL AND/OR EQUIPMENT INDICATED FOR SALVAGE SHALL BE DELIVERED TO THE LOCATION DIRECTED BY THE OWNER. ALL OTHER DEMOLITION MATERIAL SHALL BECOME THE PROPERTY OF THE CONTRACTOR AND SHALL BE PROPERLY REMOVED FROM THE SITE.

ALL ELECTRICAL OPENINGS NOT USED SHALL BE CAPPED AND SEALED.

EXISTING CONDITIONS WERE OBTAINED FROM AVAILABLE DRAWINGS AND ARE NOT GUARANTEED TO BE COMPLETE OR CORRECT. THE CONTRACTOR SHALL SURVEY AND VERIFY EXISTING CONDITIONS PRIOR TO SUBMITTING BID AND STARTING WORK.

25. **LUG REQUIREMENTS**

ALL LUGS SHALL BE TWO-HOLE, LONG-BARREL, COMPRESSION TYPE LUGS WITH INSPECTION HOLES. LUGS SHALL BE CRIMPED WITH NON-FLASHING TYPE DIES, SUCH AS PRODUCED BY THE THOMAS AND BETTS COMPANY. EACH LUG SHALL BE HEXAGONALLY SHAPED UNDER A MINIMUM OF 10 TONS OF COMPRESSIVE FORCE. EACH LUG SHALL BE CRIMPED TWICE UPON INSTALLATION AND WILL BE INSPECTED BY THE OWNER. THERE SHALL BE NO "SHINERS" ABOUT ANY LUG.

NOTES:

1. HEIGHTS SHOWN ARE TYPICAL TO CENTERLINE OF BOX UNLESS NOTED OTHERWISE. ALL DUPLEX RECEPTACLES SHALL BE MOUNTED VERTICALLY.
2. WHEREVER DEVICES ARE INDICATED TO BE ABOVE DOORS, DEVICE SHALL BE CENTERED BETWEEN TOP OF DOOR TRIM AND CEILING LINE.
3. MOUNTING HEIGHTS SHOWN ON ARCHITECTURAL ELEVATIONS SHALL GOVERN OVER THOSE SHOWN ABOVE.
4. FOR CEILINGS BELOW 7'-4", FIRE ALARM STROBE OR HORN/STROBES SHALL BE WALL MOUNTED 6" BELOW FINISHED CEILING.

1 EQUIPMENT AND DEVICE MOUNTING HEIGHT DETAIL
N.S.

TENG

TENG & ASSOCIATES, INC.
ENGINEERS/ARCHITECTS/PLANNERS
330 N. BRAND BLVD., GLENDALE, CA 91203
TELEPHONE: 818/520-1100

1	01-20-04 ISSUED FOR PERMIT	TDN
NO. DATE	DESCRIPTION	BY
REVISIONS		
DATE	DECEMBER 17, 2002	
DRAWN	JCM	
CHECKED	JDC	
APPROVED	TDN	
PROJECT NO.	03-9016-00	

CAUTION: DO NOT SCALE DRAWINGS. THE REPRODUCTION MAY BE AT A SIZE DIFFERENT FROM ORIGINALLY DRAWN. THE OWNER & TENG ASSUME NO RESPONSIBILITY FOR INCORRECT SCALING. UNAUTHORIZED REPRODUCTION OR REUSE IS STRICTLY PROHIBITED.

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OFFGASES MICRO TURBINES

St. James Oil Field
814 WEST 23rd STREET
LOS ANGELES, CALIFORNIA 90018

ELECTRICAL NOTES

E1.0

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ABBREVIATIONS LIST

AMP	AMPERE
AC	ALTERNATING CURRENT
A/C	AIR CONDITIONING
ACCU	AIR COOLED CONDENSING UNIT
AF	AMP FRAME
AFF	ABOVE FINISHED FLOOR
AIC	AMPS INTERRUPTING CURRENT
AM	AMMETER
AS	AMMETER SWITCH
AT	AMP TRIP
ATS	AUTOMATIC TRANSFER SWITCH
AWG	AMERICAN WIRE GAUGE (WIRE SIZE)
BMS	BUILDING MANAGEMENT SYSTEM
BATT	BATTERY
C	CONDUIT
CB	CIRCUIT BREAKER
CCTV	CLOSED-CIRCUIT TELEVISION
CH	CHILLER
CHG	CHARGER
CKT	CIRCUIT
CM	CIRCULAR MILS
COGB	CENTRAL OFFICE GROUND BAR
COMM	COMMUNICATION OR COMMUNICATIONS
CONN	CONNECTOR
CRAC	COMPUTER ROOM AIR CONDITIONER
CT	CURRENT TRANSFORMER
DC	DIRECT CURRENT
DCGB	DC GROUND BAR
DDC	DIRECT DIGITAL CONTROL
DIAG	DIAGRAM
DISC	DISCONNECT
DP	DISTRIBUTION PANEL
DWG	DRAWING
EDH	ELECTRIC DUCT HEATER
EF	EXHAUST FAN
EMER	EMERGENCY
EMT	ELECTRICAL METALLIC CONDUIT
ENCL	ENCLOSURE
EQUIP	EQUIPMENT
EWC	ELECTRIC WATER COOLER
EX	EXISTING, TO REMAIN
FTR	FITTER
FLA	FULL-LOAD AMPS
FMS	FACILITY MANAGEMENT SYSTEM
FIXT	FIXTURE
G	GROUND WIRE
GF	GROUND FAULT INTERRUPTER
GND	GROUND
H-O-A	HAND-ON/OFF-AUTO
HP	HORSE POWER
HPS	HIGH PRESSURE SODIUM
HT	HEIGHT
HTR	HEATER
HV	HIGH VOLTAGE
IG	ISOLATED GROUND
J	JUNCTION BOX
KCMIL	KILO CIRCULAR MILS (WIRE SIZE)
KV	KILOVOLT
KVA	KILOVOLT AMPERE
KW	KILOWATT
LPI	LIGHTNING PROTECTION INSTITUTE
LTG	LIGHTING
LV	LOW VOLTAGE
M	METER
MAN	MANUAL
MCB	MAIN CIRCUIT BREAKER
MCC	MOTOR CONTROL CENTER
MDP	MAIN DISTRIBUTION PANEL
MECH	MECHANICAL
MFR	MANUFACTURER
MGB	MAIN/MASTER GROUND BAR
MH	MAN HOLE
MISC	MISCELLANEOUS
MOP	METHOD OF PROCEDURE
MS	MOTION SENSOR
MSGB	MASTER STATION GROUND BAR
MSS	MAIN SERVICE SWITCH
MTD	MOUNTED
MTS	MANUAL TRANSFER SWITCH
NC	NORMALLY CLOSED
NEUT	NEUTRAL
NFPA	NATIONAL FIRE PROTECTION ASSOCIATION
NIC	NOT IN CONTRACT
NTS	NOT TO SCALE
OC	ON-CENTER (MEASUREMENT)
OCPD	OVER-CURRENT PROTECTIVE DEVICE
OFCI	OWNER-FURNISHED, CONTRACTOR-INSTALLED
P	POLE
PBO	PROVIDED (AND INSTALLED) BY OTHERS
PDU	POWER DISTRIBUTION UNIT
PH	PHASE
PNL	PANEL
PRI	PRIMARY
PVC	POLYVINYL CHLORIDE (CONDUIT)
PWR	POWER
RECP	RECEPTACLE
RGSC	RIGID STEEL CONDUIT
RMC	RIGID METALLIC CONDUIT
SD	SMOKE DETECTOR
SEC	SECONDARY
SF	SUPPLY FAN
SP	SINGLE-POLE OR SPARE
STBY	STANDBY
SW	SWITCH
TB	TERMINAL BLOCK
TEL	TELEPHONE
TGB	TERMINAL GROUND BAR
TVSS	TRANSIENT VOLTAGE SURGE SUPPRESSION
UG	UNDERGROUND
UH	UNIT HEATER
UL	UNDERWRITERS' LABORATORY
UNO	UNLESS NOTED OTHERWISE
V	VOLTS
VA	VOLT-AMPERES
VAC	VOLTAGE, ALTERNATING CURRENT
VAV	VARIABLE AIR VOLUME (HVAC)
VDC	VOLTAGE, DIRECT CURRENT
VFC	VARIABLE FREQUENCY CONTROLLER (HVAC)
VFD	VARIABLE FREQUENCY DRIVE (HVAC)
VM	VOLT METER
VS	VOLTAGE SENSOR
W	WATT OR WIRE
WP	WEATHER PROOF
WSA	WIRE SIZING AMPS
XFMR	TRANSFORMER

SYMBOL LIST

SYMBOL	DESCRIPTION
3b	SINGLE POLE SWITCH – NUMBER INDICATES CIRCUIT, LETTER INDICATES SWITCHING CONTROL.
2P	TWO POLE SWITCH
3b 3W 4W	THREE WAY SWITCH – NUMBER INDICATES CIRCUIT, LETTER INDICATES SWITCHING CONTROL. "4W" DENOTES FOUR WAY SWITCH.
M	MANUAL MOTOR STARTER SWITCH (INCLUDES THERMAL OVERLOADS)
T	THERMAL OVERLOAD SWITCH "TP", PROVIDE WITH PILOT LIGHT
	SINGLE POLE SWITCH WITH PILOT LIGHT
	DIMMER SWITCH (600W, UNO)
	DUPLEX RECEPTACLE – 20A, 120 VOLT, 1P, 3W, NEMA 5-20R.
	QUADRUPLEX RECEPTACLE – 20A, 120 VOLT, 1P, 3W, NEMA 5-20R (TWO DUPLEX RECEPTACLES WITH COMMON COVERPLATE).
GFI	GROUND FAULT INTERRUPTER RECEPTACLE
WP	WEATHER PROOF ENCLOSURE CONTAINING GROUND FAULT INTERRUPTER RECEPTACLE
	SINGLE TWIST-LOCK ISOLATED-GROUND RECEPTACLE – 20A, 120 VOLT, 1P, 2W + IG, NEMA L14-20. PROVIDE ORANGE RECEPTACLE WITH WHITE COVERPLATE.
	DUPLEX ISOLATED-GROUND RECEPTACLE – 20A, 120 VOLT, 1P, 2W + IG, NEMA 5-20R. PROVIDE ORANGE RECEPTACLE WITH WHITE COVERPLATE.
	QUADRUPLEX ISOLATED-GROUND RECEPTACLE – 20A, 120 VOLT, 1P, 2W + IG, NEMA 5-20R (TWO DUPLEX RECEPTACLES WITH COMMON COVERPLATE). PROVIDE ORANGE RECEPTACLE WITH WHITE COVERPLATE.
A	120V-30A-1PH-2P-3W, LOCKING, NEMA L5-30R. CKT TO 30A 1P CB WITH (2)#10 AND (1)#10 GRD IN 3/4"C, UNO.
	FUSE
	CIRCUIT BREAKER – THERMAL MAGNETIC UNLESS NOTED OTHERWISE
	CIRCUIT BREAKER – DRAWOUT TYPE
	JUNCTION BOX WITH BLANK COVER
	CEILING OR WALL MOUNTED JUNCTION BOX WITH BLANK COVER AND A MAX. 6'-0" LENGTH OF 3/4" SEALTITE FLEXIBLE CONDUIT
	PANEL, SURFACE-MOUNTED
	POWER DISTRIBUTION PANEL
	MISCELLANEOUS PANELS AND CABINETS
	COMBINATION STARTER AND NON-FUSED DISCONNECT SWITCH
	NON-FUSED DISCONNECT SWITCH, 3P-30A UNLESS NOTED OTHERWISE. PROVIDE LIQUID TIGHT FLEXIBLE CONDUIT AND MAKE FINAL CONNECTION.
	FUSED DISCONNECT SWITCH, 3P-30A UNLESS OTHERWISE NOTED. PROVIDE LIQUID-TIGHT FLEXIBLE CONDUIT AND MAKE FINAL CONNECTION.
	TELEPHONE/DATA OUTLET – PROVIDE OUTLET BOX WITH BLANK COVER PLATE 18" ABOVE FINISHED FLOOR ON 3/4" CONDUIT WITH BUSHED TAIL CONTAINING NYLON PULL WIRE STUBBED INTO ACCESSIBLE CEILING CAVITY.
W	TELEPHONE OUTLET. WALL-MOUNTED AT 52" AFF.
A	FLUORESCENT LUMINAIRE PER LUMINAIRE SCHEDULE.
	LIGHTING FIXTURE CONNECTED TO THE EXIT AND EMERGENCY LIGHTING SYSTEM.
	WALL-MOUNTED EMERGENCY LIGHTING FIXTURE WITH INTEGRAL BATTERY POWER SUPPLY.
#1	DIRECTIONAL EXIT SIGN, WHERE SHADING INDICATES LIGHTED FACE AND THE ARROW INDICATES THE STENCILED EXIT DIRECTION. CONNECT ALL EXIT SIGNS TO THE EXIT AND EMERGENCY LIGHTING SYSTEM. NUMBER INDICATES THE STENCILED INSCRIPTION.

SINGLE-FACE
#1 "FIRE ESCAPE"
#2 "STAIRWAY"
#3 "EXIT"
#4 "FIRE ESCAPE"
#5 "STAIRWAY"
#6 "EXIT"
#7 "FIRE ESCAPE"
#8 "STAIRWAY"
#9 "EXIT"
#10 "FIRE ESCAPE"
#11 "STAIRWAY"
#12 "EXIT"

DOUBLE-FACE
#13 FLUSH OR RECESSED
#14 TRIANGLE
#15 ELEVATOR
#16 FIRE ESCAPE
#17 "STAIRWAY"
#18 "EXIT"
#19 "FIRE ESCAPE"
#20 "STAIRWAY"
#21 "EXIT"
#22 "FIRE ESCAPE"
#23 "STAIRWAY"
#24 "EXIT"

SYMBOL LIST (CONTINUED)

SYMBOL	DESCRIPTION
	MOTOR WITH HORSEPOWER RATING AS INDICATED. PROVIDE LIQUID-TIGHT FLEX CONNECTION AND JUNCTION BOX.
	EQUIPMENT IDENTIFICATION TAG
	CONDUIT, STUBBED DOWN
	CONDUIT, STUBBED UP
	CONDUIT RUN CONCEALED IN CEILING OR WALL; CONDUIT RUN CONCEALED BELOW FINISHED FLOOR; CONDUIT RUN EXPOSED ON CEILING OR WALL. ARROWHEAD DENOTES HOMERUN TO PANELBOARD. SLASH LINES INDICATE QUANTITY OF WIRE. NEUTRAL WIRE SHOWN AS A LONG LINE, PHASE WIRE AND SWITCH LEGS SHOWN AS SHORT LINES, GROUND WIRE SHOWN AS A LONG LINE WITH A DOT, AND ISOLATED GROUND WIRE SHOWN AS A LONG DOTTED LINE.
EPO	EMERGENCY POWER OFF SWITCH AS REQUIRED PER NEC 645, MTD. 42" ABOVE FINISHED FLOOR. SWITCH SHALL BE RED-COLORED, MUSHROOM-HEAD TYPE WITH PROTECTIVE COVER. PROVIDE PLACARD ABOVE SWITCH INDICATING THE ASSOCIATED LOAD.
UB-1-19	50-FOOT CORD REEL WITH ISOLATED-GROUND QUADRUPLEX TYPE RECEPTACLE (DANIEL WOODHEAD #953 OR APPROVED EQUAL), WHERE "UB-1" DENOTES THE HOMERUN PANEL AND "19" DENOTES THE CIRCUIT NUMBER. CORD REEL SHALL BE MOUNTED TO BUILDING STRUCTURE ABOVE. PROVIDE A STOP TO THE CORD REEL TO MAINTAIN AN ELEVATION OF 7'-0" ABOVE FINISHED FLOOR. VERIFY EXACT LOCATION WITH THE OWNER PRIOR TO ROUGH-IN. REFER TO FLOOR PLAN FOR PANEL DESIGNATION AND CIRCUIT NUMBER.
A	AIR TERMINAL, (1/2" X 24") COPPER WITH BRONZE PARAPET BASE. REFER TO DETAILS.
H	AIR TERMINAL, (1/2" X 24") COPPER WITH BRONZE FLAT-SURFACE BASE. REFER TO DETAILS.
C	AIR TERMINAL, (1/2" X 24") COPPER WITH BRONZE PARAPET BASE AND DOWN CONDUCTOR. REFER TO DETAILS.
EX	AIR TERMINAL, (1/2" X 24"), EXISTING TO REMAIN.
SM	BOND, TAP CONDUCTOR TO STEEL OR METALLIC OBJECT. REFER TO DETAILS.
T	BOND, TAP CONDUCTOR TO GROUNDING/LIGHTNING SYSTEM CONDUCTOR. REFER TO DETAILS.
F	BOND, TAP CONDUCTOR TO METALLIC FENCING. REFER TO DETAILS.
	COPPER, CLASS I LIGHTNING CONDUCTOR. REFER TO NOTES FOR SIZING AND DETAILS FOR INSTALLATION.
	COPPER GROUNDING CONDUCTOR. REFER TO NOTES FOR SIZING AND DETAILS FOR INSTALLATION.
	GROUND ROD, (3/4" X 10', UNO) COPPER-CLADDED WITH CADWELD CONNECTIONS. REFER DETAILS FOR INSTALLATION.
A/V	AUDIBLE GENERAL ALARM WITH VISUAL STROBE
SD	SMOKE DETECTOR
HD	HEAT DETECTOR
S	FIRE ALARM PULL STATION
	WALL MOUNT PASSIVE INFRARED MOTION DETECTOR WITH OVER-RIDE SWITCH
MD	CEILING MOUNTED PASSIVE INFRARED MOTION DETECTOR
HD	WALL MOUNTED PASSIVE INFRARED HALLWAY MOTION DETECTOR
	RACEWAY/CONDUIT UP FROM PLAN VIEW
	RACEWAY/CONDUIT DOWN FROM PLAN VIEW

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REVISIONS
DATE DECEMBER 17, 2003
DRAWN JCM
CHECKED JDC
APPROVED TDN
PROJECT NO. 00-9016-00

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ELECTRICAL SYMBOLS AND ABBREVIATIONS
E1.1

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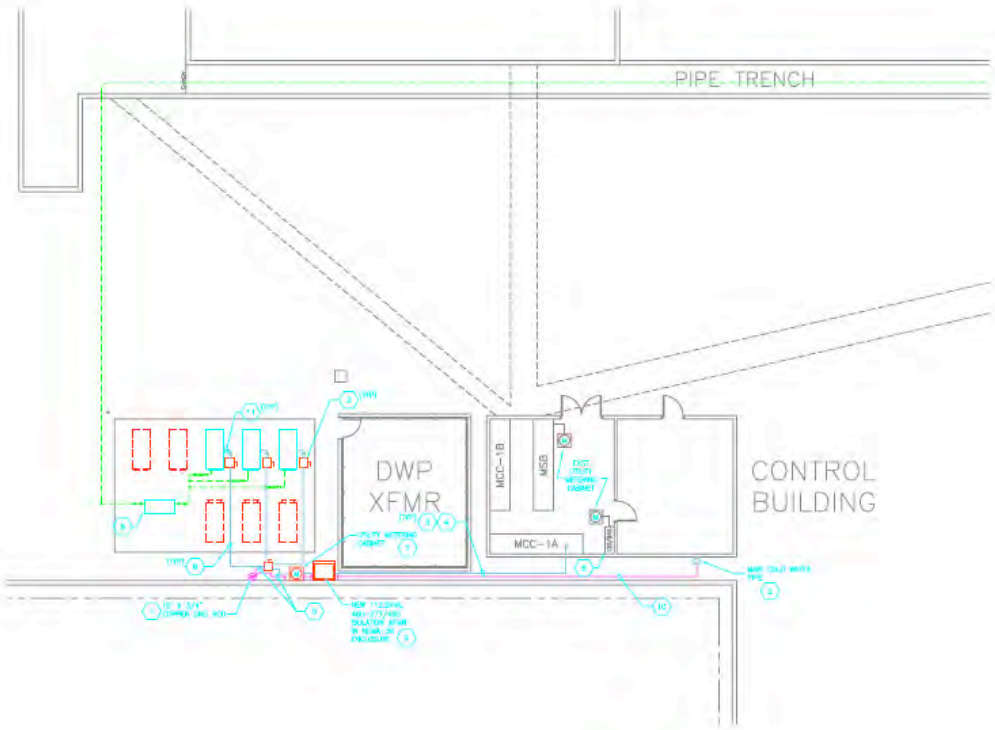

1 ELECTRICAL SITE PLAN

1"=10'-0"

GENERAL NOTES - INSTALLATION:

SEE DRAWING E1.1 FOR GENERAL NOTES.

KEY NOTES:

1. REFER TO DETAILS 4/E3.0 AND 5/E3.0 FOR CONNECTION TO THE GROUND ROD.
2. REFER TO DETAIL 3/E3.0 FOR CONNECTION TO THE MAIN COLD WATER PIPE.
3. INSTALLATION OF THE NEW EQUIPMENT SHALL MEET THE BRACING REQUIREMENTS FOR SEISMIC ZONE 4. REFER TO DRAWING E4.2 FOR THE REQUIRED ANCHORAGE.
4. INSTALL FULL SIZED AS REQUIRED BY THE LATEST EDITION OF NEC.
5. GROUND CONDUCTOR. REFER TO DRAWING 2/E3.0 FOR THE REQUIRED SIZE.
6. FIBERGLASS CONDUITS ARE SURFACE MOUNTED FROM EACH METERPEDESTAL ENTRANCE TO THE 200A DISCONNECT LOCATED ON THE SOUTH WALL. PROVIDE A STEEL WARPED COVER OVER THE CONDUIT TO PROVIDE SURFACE PROTECTION.
7. PROVIDE METERING EQUIPMENT AS REQUIRED BY DWP. COORDINATE SIZES, LOCATION OF THE METERING CABINET WITH DWP REPRESENTATIVE.
8. PROVIDE 3#12, #10, & 3/4"C, AND CONDUITS ON THE SPARE 30A BREAKER AT POSITION 3-4, FROM THE EXISTING 120/240V PANEL, TO SERVE THE NEW REFRIGERATOR/OFFICE.
9. PROVIDE MOUNTING PAD.
10. REFER TO DETAIL 1/E3.0 FOR SUPPORTING THE GROUND CONDUCTOR.
11. PROVIDE LIQUID TIGHT METALLIC FLEXIBLE CONDUIT. LENGTH OF THE FLEXIBLE METALLIC CONDUIT SHALL NOT EXCEED 6'.

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PROJECT NO.	1C-0016-01

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ELECTRICAL SITE PLAN

E2.1

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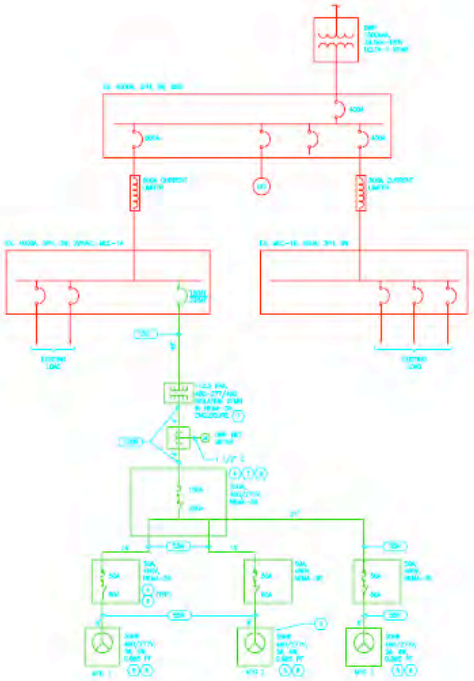

1 ELECTRICAL SINGLE-LINE DIAGRAM

2 GROUNDING SINGLE-LINE DIAGRAM

GENERAL NOTES: SINGLE-LINE DIAGRAM

1. PROVIDE EACH NEW OR MODIFIED ELECTRICAL DISCLOSURE (E.G. DISCONNECT SWITCH, PANEL, ETC.) WITH A PHENOLIC LABEL, COLORED BLACK WITH ENGRAVED WHITE LETTERING. EACH LABEL SHALL INCLUDE AT LEAST TWO LINES OF TEXT: THE DISTINCTIVE NAME IN 1"-TALL LETTERING ON THE FIRST LINE AND ITS "FED FROM" CIRCUIT INFORMATION IN 3/32"-TALL LETTERING ON THE SECOND LINE. WHERE APPLICABLE, ADD A THIRD LINE WITH 1/2"-TALL LETTERING OF ITS "FEEDER"-LINE INFORMATION.
2. PROVIDE TEXTURE WITH FOR CABLES AND EQUIPMENT AS INDICATED IN THE INTERPRETATION BEHIND DIAGRAMS THE SUB SYSTEM.
3. THE CONTRACTOR SHALL PROVIDE THE ALARM WIRING FROM THE FIRE EQUIPMENT TO THE EXISTING ALARM BOX. COORDINATE WITH THE CONTRACTOR AND THE PROJECT MANAGER.

KEY NOTES: SINGLE-LINE DIAGRAM

1. INSTALL "STRUT" GROUND ROD AT CONNECTION TO THE ROD SHALL BE MADE IN TUNTSMAN WELL.
2. REFER TO DETAIL 3/E3.0 FOR GROUNDING CONNECTION.
3. INSTALL CONTROL WIRING BETWEEN MT01, MT02, AND MT03. MT01 SHALL BE UTILIZED AS MASTER UNIT.
4. THE POWER DISCONNECT SWITCHES SHALL BE MOUNTED IN A WEATHER PROOF ENCLOSURE. THE ENCLOSURE SHALL NOT BE MOUNTED ON MORE THAN(2) LINES. THE DISCONNECT SWITCHES SHALL BE EQUIPPED WITH TWO LOCKS SO THAT THE DISCONNECTS SWITCHES CAN LOCKED IN "OFFS" POSITION AND NO ONE UNTIMED OR UNAUTHORIZED SHALL NOT BE ABLE TO OPERATE AS DISCONNECTING DEVICE.
5. MICRO TURBINES PROTECTIVE RELAY SETTINGS SHALL BE SET AS FOLLOW
   - UNDER VOLTAGE RELAYS: 420V FOR OVER 10 SECONDS.
   - OVER VOLTAGE RELAYS: 480V FOR OVER 10 SECONDS.
   - UNDER VOLTAGE RELAY: 120V FOR OVER 1.5 SECONDS.
   - OVER VOLTAGE RELAY: 120V FOR OVER 0.5 SECONDS.
   - UNDER FREQUENCY: 59.3 HZ FOR OVER 0.5 SECONDS.
   - OVER FREQUENCY: 60.5 HZ FOR OVER 0.5 SECONDS.
   - RATE OF CHANGE OF FREQUENCY: ACTIVE ANTI-ISLANDING PROTECTION ANTIALLO.
6. PROVIDE 3/4" CONDUIT WITH PULL STRING FROM THE MICRO TURBINE TO THE CONTROL BUILDING DEDICATED TELEPHONE OR REMOTE MONITORING PANEL WITH THE OWNER.
7. REFER TO DETAIL 2/E3.0 FOR DISCONNECT SWITCH AND TRANSFORMER EXCHANGE REQUIREMENT.
8. PROVIDE CURRENT LIMITING FUSES TO COMPLY FOR ALL NEW DISCONNECT SWITCHES.
9. THE MICRO TURBINES OTHER MAXIMUM FAULT CURRENT CONTRIBUTION IS 11KA.

FEEDER SCHEDULE

NOTE: ALL FEEDERS AND ALARMS MUST BE LABELED

NO	CONDUCTORS	CONDUIT	NO	CONDUCTORS	CONDUIT
1C	BRANCH WIRING CONDUCTOR	SEE NOTES			
F1	CROSSOVER FEEDER	-	MT01	PRIMARY MT WIRING	SEE NOTES
3C	(3)#12, (1)#12 G	3/4"	(3)#12, (1)#12 G	3/4"
4C	(4)#12, (1)#12 G	3/4"	(4)#12, (1)#12 G	3/4"
4T	(4)#8, (1)#10 G	1"	(4)#8, (1)#10 G	1"
5C	(5)#8, (1)#8 G	1"	(5)#8, (1)#8 G	1-1/4"
7C	(7)#4, (1)#8 G	1-1/4"	(7)#4, (1)#8 G	1-1/4"
8C	(8)#4, (1)#8 G	1-1/4"	(8)#4, (1)#8 G	1-1/4"
9C	(9)#4, (1)#8 G	1-1/2"	(9)#4, (1)#8 G	1-1/2"
10C	(10)#4, (1)#8 G	1-1/2"	(10)#4, (1)#8 G	2"
15C	(15)#4, (1)#8 G	1-1/2"	(15)#4, (1)#8 G	2"
17C	(17)#4, (1)#8 G	2"	(17)#4, (1)#8 G	2"
20C	(20)#4, (1)#8 G	2"	(20)#4, (1)#8 G	2"
23C	(23)#4, (1)#8 G	2"	(23)#4, (1)#8 G	2-1/2"
30C	(30)#2/0, (1)#8 G	2-1/2"	(30)#2/0, (1)#8 G	3"
40C	(40)#2/0, (1)#8 G	3-1/2"	(40)#2/0, (1)#8 G	3"
51C	(51)#2/0, (1)#8 G	3"	(51)#2/0, (1)#8 G	3"
53C	(53)#2/0, (1)#8 G	3"	(53)#2/0, (1)#8 G	3"
58C	(58)#2/0, (1)#8 G	3"	(58)#2/0, (1)#8 G	3-1/2"
60C	2 SETS—(30)#2/0, (1)#8 G; (1)#2/0—TOTAL OF (61)#2/0, (2)#8 G	2"	(60)#2/0, (1)#8 G; (1)#2/0—TOTAL OF (61)#2/0, (2)#8 G	3-1/2"
67C	(67)#2/0, (1)#8 G	3-1/2"	(67)#2/0, (1)#8 G	4"

NOTES:

1. WHEN USING PARALLEL RUNS FOR A FEEDER, THE EQUIPMENT GROUNDING CONDUCTOR IN EACH PARALLEL RUN SHALL BE SIZED FOR THE TOTAL AMPACITY OF THE OVER CURRENT PROTECTION DEVICE (REFER TO NEC ARTICLE 250.122).
2. WHERE OVER CURRENT PROTECTION DEVICES (OCPD) ARE INDICATED WITH THE "LSIG" NOTATION, THE MAY BE COMBINATION THERMAL MAGNETIC OCPD WITH PROGRAMMABLE TRIP UNITS WHERE:
   L = LONG TERM TRIP
   S = SHORT TERM TRIP
   I = INSTANTANEOUS TRIP
   G = GROUND FAULT TRIP
   (D) = ELECTRICALLY DYNAMIC
3. (F) - FEEDER-TERMINATED CONTACTOR-INSTALLED TRIP - PROVIDED (AND INSTALLED) BY OWNER.
4. (E) - FEEDER GROUND MONITORING DEVICE. THE FEEDER IS DESIGNATED WITH THE "E" NOTATION. AN ADDITIONAL GROUNDING CONDUCTOR OF THE SAME SIZE SPECIFIED FOR EQUIPMENT GROUNDING SHALL BE PROVIDED, ROUTED AND TERMINATED FOR THE ISOLATED GROUND BUSBAR.
5. CONDUIT SIZES ARE MINIMUM. INCREASE FOR LONG OR DIFFICULT RUNS.
6. ABOVE SET AMBIENT PRESENTS NEC SIZE PER NEC.
7. USE NEC CONDUIT FILL CHARTS TO BE DIRECTED.

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PARTIAL ELECTRICAL SINGLE-LINE DIAGRAM

E3.0

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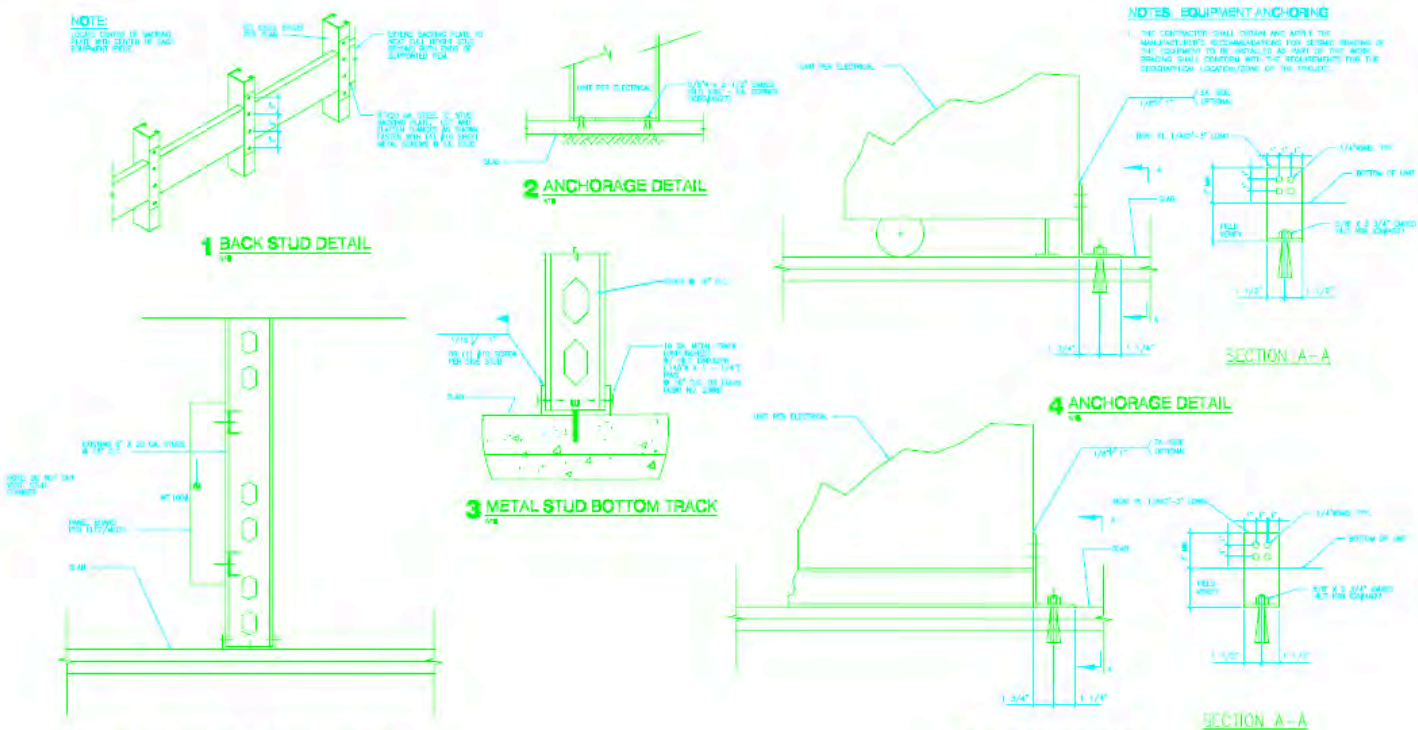

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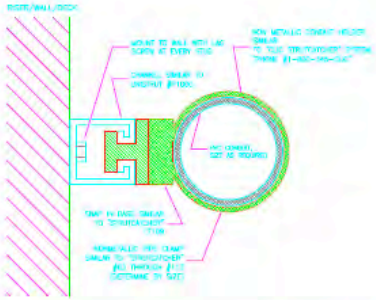
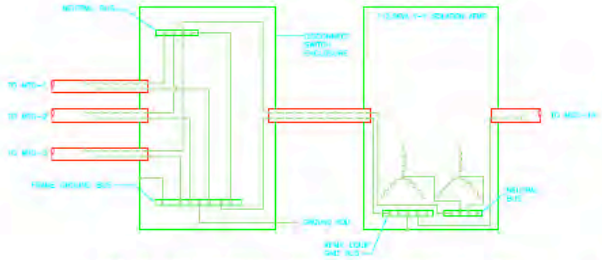
EQUIPMENT ANCHORING

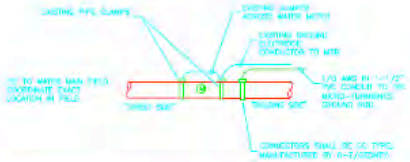
E4.0



1 GROUND CONDUCTOR SUPPORT



2 MICRO-TURBINE GROUNDING CONNECTION



3 CONNECTION TO THE MAIN WATER PIPE

4 CADWELD: MOLD NO. 1

5 CADWELD: MOLD NO. 2

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ELECTRICAL DETAILS

E5.0

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PROJECT NO. 26-6289-06

INDEX OF DRAWINGS

REFERENCE

G1.0 TITLE SHEET

MECHANICAL

M2.1 MECHANICAL SITE PLAN AND DETAIL PLANS
M3.1 MECHANICAL DETAILS AND SCHEMATICS

ELECTRICAL

E1.0 ELECTRICAL GENERAL NOTES
E1.1 ELECTRICAL SYMBOLS AND ABBREVIATIONS
E2.1 ELECTRICAL SITE PLAN
E3.0 PARTIAL SINGLE LINE DIAGRAM
E4.0 EQUIPMENT ANCHORING
E5.0 ELECTRICAL DETAILS

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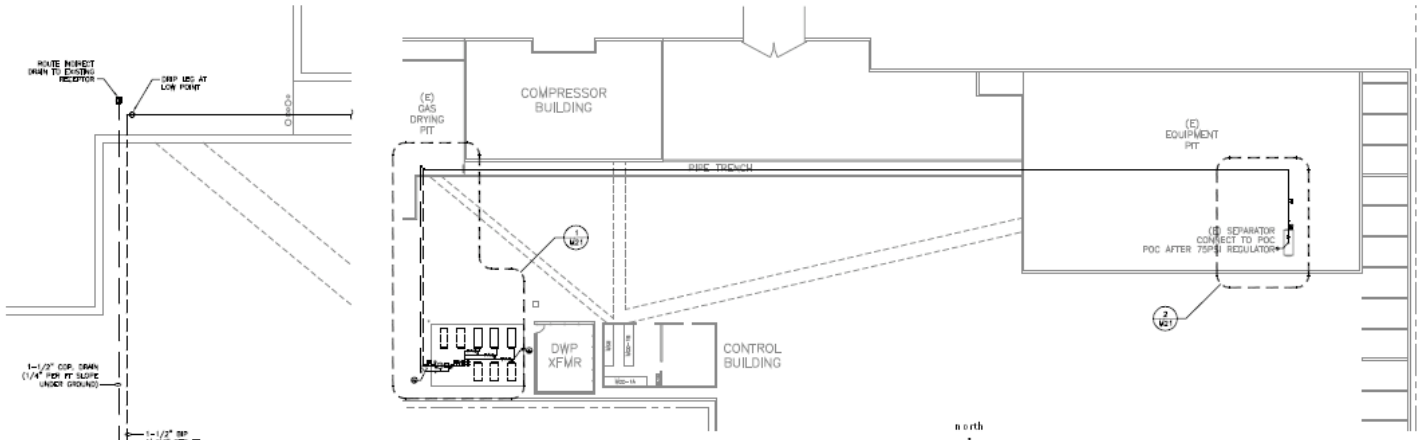
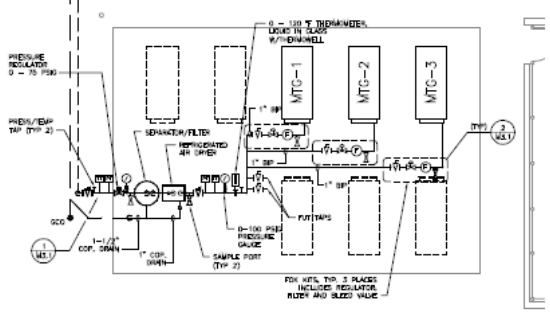
TITLE SHEET

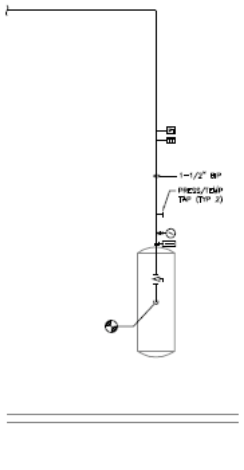
G1.0



1 MECHANICAL SITE PLAN
1/8"=1'-0"



2 PARTIAL MECHANICAL SITE PLAN
1/8"=1'-0"



3 PARTIAL MECHANICAL SITE PLAN
1/8"=1'-0"

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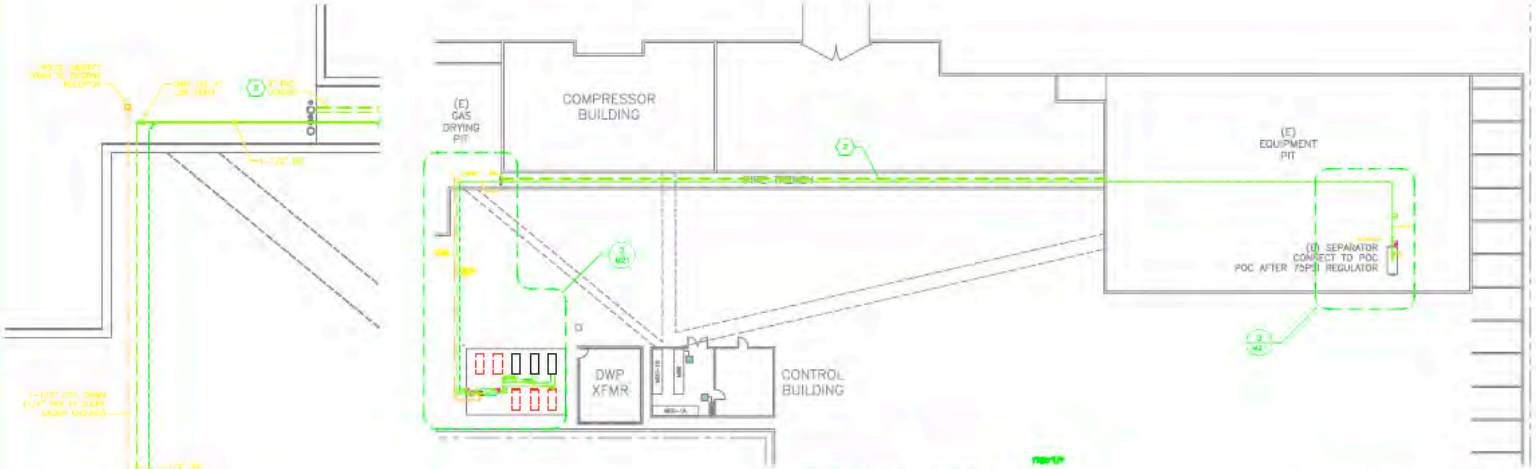
OFFGASES
MICRO TURBINES

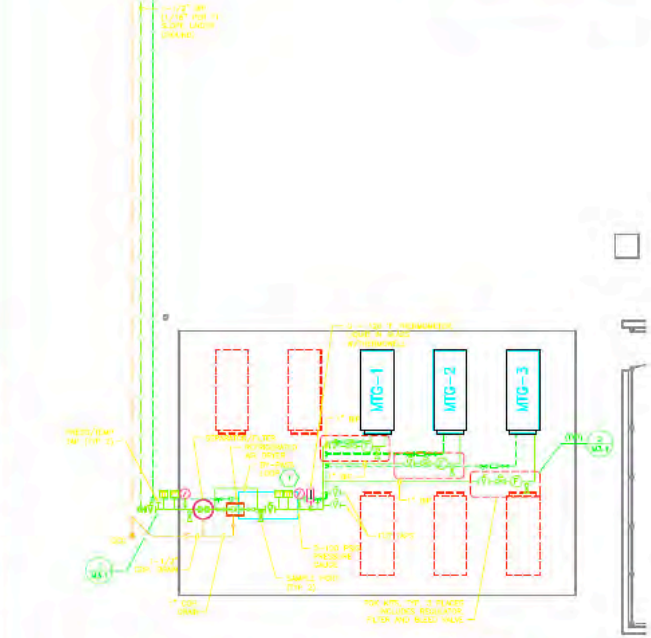
St. James Oil Field
814 WEST 23rd STREET
LOS ANGELES, CALIFORNIA 90018

MECHANICAL SITE PLAN AND PARTIAL PLANS

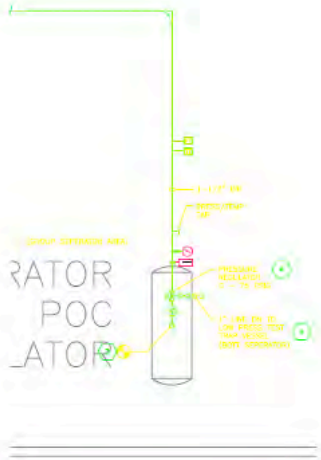
M 2.1



1 MECHANICAL SITE PLAN



2 PARTIAL MECHANICAL SITE PLAN



3 PARTIAL MECHANICAL SITE PLAN

GENERAL NOTES:

1. SEE DRAWING M2.1 FOR ADDITIONAL NOTES

KEY NOTES:

1. PROVIDE REFRIGERATED DRYER LINE BY-PASS LOOP WITH ISOLATION VALVES.
2. PROVIDE (1) 4" PVC CONDUIT (LENGTH SLOTTED IN TRENCH FOR FUTURE PIPING OR CONTROL WIRING.
3. CONNECT NEW 1 1/2" GAS LINE AT EXISTING 2" LINE AT THE GROUP TRAP VESSEL (TOP DEPERATOR).
4. INSTALL TO PSI (20-40 PSI ADJ) BACK PRESSURE VALVE AND 1" BOTTOM DISCHARGE LINE DOWN TO LOW PRESSURE TEST TRAP VESSEL (BOTTOM SEPERATOR).

TENG

TENG & ASSOCIATES, INC.
ENGINEERS/ARCHITECTS/PLANNERS
330 N. BRAND BLVD., GLENDALE, CA 91803
TELEPHONE: 818/539-1100

NO.	DATE	DESCRIPTION	BY
1	01-22-04	ISSUED FOR PERMIT	TBH

REVISIONS

DATE	DECEMBER 17, 2003
DRAWN	JDS
CHECKED	JCM
APPROVED	TBH
PROJECT NO.	00-0018-00

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OFFGASES MICRO TURBINES

51 James Oil Field
814 WEST 23rd STREET
LOS ANGELES, CALIFORNIA 90018

MECHANICAL SITE PLAN AND PARTIAL PLANS

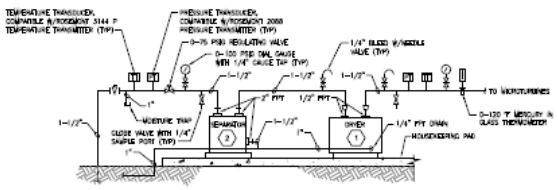
M2.1

GENERAL NOTES:

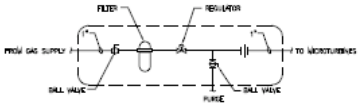
1. SEE DRAWING M3.1 FOR ADDITIONAL NOTES.

KEY NOTES:

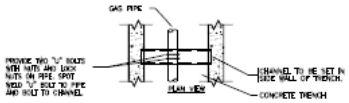
1. NEW GAS REFRIGERATED AIR DRYER, MODEL NOT SS 30.
2. HANOVER VERTICAL 2 PHASE SEPARATOR, 24" O.D. x 7'-6" SS @ 125#.



1 GAS CONDITIONING SCHEMATIC
NTS



2 FOX KIT SCHEMATIC
NTS



SCHEDULE		
SIZE OF PIPE	SIZE OF "U" BOLT	SIZE OF CHANNEL
1" TO 2"	3/8" DIA.	3" – 10 1/2#

SCHEDULE FOR 8 FT. SPAN OR LESS

3 PIPE TRENCH ANCHOR
NTS

TENG

TENG & ASSOCIATES, INC.
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330 N. BRAND BLVD., GLENDALE, CA 91203
TELEPHONE: 818/539-1100

NO.	DATE	DESCRIPTION	BY

REVISIONS

DATE	DECEMBER 17, 2003
DRAWN	JSR
CHECKED	JCM
APPROVED	TGN
PROJECT NO.	

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OFFGASES
MICRO TURBINES

St. James Oil Field
814 WEST 23rd STREET
LOS ANGELES, CALIFORNIA 90018

MECHANICAL DETAILS AND SCHEMATICS

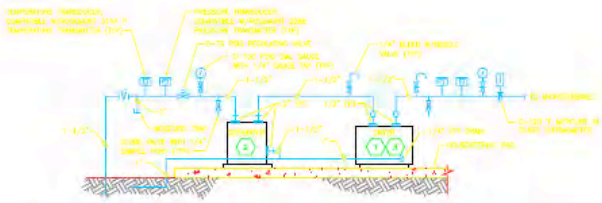
M 3.1

GENERAL NOTES

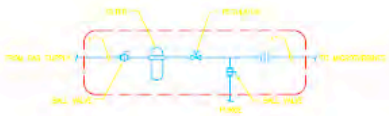
1. SEE DRAWING M0.1 FOR ADDITIONAL NOTES

KEY NOTES

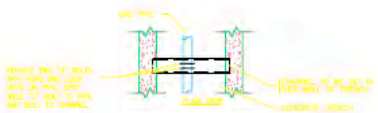
1. NEW GAS REFRIGERATED AIR DRYER MODEL MHT 25 30.
2. MANFRO VERTICAL 2 PHASE SEPARATOR, 24" O.D., x 7'-0" SS & 125#
3. PRIVATE REFRIGERATED DRYER UNIT BY PARK LOOK WITH ISOLATION VALVES, METER 2/M4.1



1 GAS CONDITIONING SCHEMATIC



2 FOK KIT SCHEMATIC



SCHEDULE		
WIDTH OF PIPE	WIDTH OF TRENCH	WIDTH OF CHANNEL
12" TO 24"	24"	12" TO 24"

SCHEDULE FOR 6 FT. SPAN OR LESS

3 PIPE TRENCH ANCHOR

TENG

TENG & ASSOCIATES, INC.
ENGINEERS/ARCHITECTS/PLANNERS
332 N. BRAND BLVD., GLENDALE, CA 91203
TELEPHONE: 818/500-1130

NO	DATE	DESCRIPTION	BY
1	01-22-04	ISSUED FOR PERMIT	TEN

REVISIONS

DATE	DECEMBER 17, 2003
DRAWN	JSR
CHECKED	JCM
APPROVED	TEN
PROJECT NO.	00-9018-30

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OFFGASES
MICRO TURBINES

St. James St. Park
614 WEST 23rd STREET
LOS ANGELES, CALIFORNIA 90015

MECHANICAL DETAILS AND SCHEMATICS

M3.1

D:\Inv-Cornell\Projects\00130-Incorporated\All DWG\Layout_DWG\00130_m31.dwg
03-18-2004 15:31:13 (MRT) Plot=PDF.pltcfg

Arnold Schwarzenegger
Governor

APPENDIX B
PHOTOS

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Bob Fickes
California Oil Producers Electric
Cooperative (COPE)

December 2008
CEC-500-02-016

Prepared By:
California Oil Producers Electric Cooperative
Bob Fickes
Long Beach, California 90802
Contract No. 500-02-016

Prepared For:
Public Interest Energy Research (PIER)
California Energy Commission

Paul Roggensack
Contract Manager

Pramod Kulkarni
Program Area Lead
Industrial, Agriculture and Water

Daryl Mills
Office Manager
Energy Efficiency Research Office

Martha Krebs, Ph. D.
PIER Research Director

Thom Kelly, Ph. D.
Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

Melissa Jones
Executive Director

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HARSH GAS PHOTOS

IR 70 with Vertical Free Water Separator and CHP Heat Loop

Sulfa-Treat Vessels with Lead/Lag Piping for Continuous Use

Electrical Meter

Double Redundant Beckwith Controller

IR 70 with CHP Heat Loop

Drilling & Production Process Falre

Electrical Interconnection

Battery Backup for Beckwith

HIGH BTU GAS PHOTOS

Termo Site During Construction

Capstone C30 Turbine with Electrical Interconnection and Transformer

Horizontal Free Water Separator and Small Gas Compressor

Three Oil Wells Returned to Production after Several Years Idle

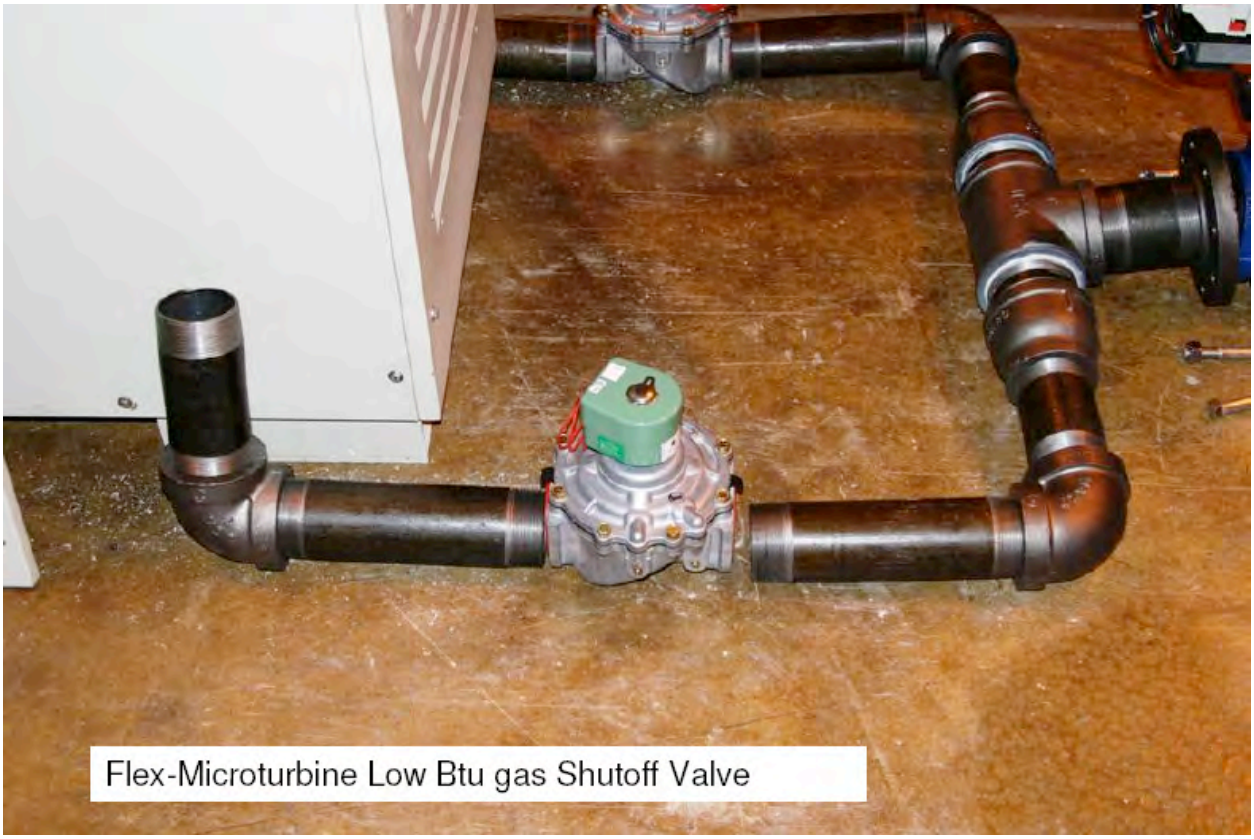
LOW BTU GAS PHOTOS

Power and Control Cable Trench

Turbine Pad Construction

Electrical Panel

Flex-Microturbine Low Btu Gas piping



Flex-Microturbine Low Btu gas Shutoff Valve

Catalytic Combustor Dissembled

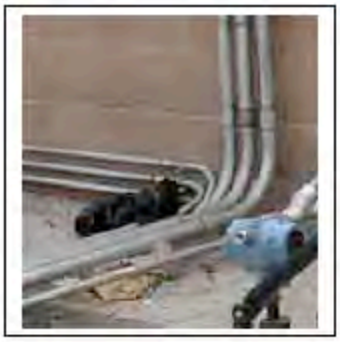
Flex-Microturbine on pad against Thermal Oxidizer background

Thermal Oxidizer (current means
to destroy low Btu Gas

MEDIUM BTU GAS PHOTOS

St James site after over 3 years of no production.

Three Capstone C30 Microturbines installed



Vertical Free Water Separator with Refrigeration Dryer Unit

Electrical interconnection with Transformer

Rear Plumbing of C30 Units

First Attempt at Soundproofing

Sound Proofing Blanket

Arnold Schwarzenegger
Governor

APPENDIX C
LIST OF GAS COMPOSITIONS

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Bob Fickes
California Oil Producers Electric Cooperative (COPE)

December 2008
CEC-500-02-016

Prepared By:
California Oil Producers Electric Cooperative
Bob Fickes
Long Beach, California 90802
Contract No. 500-02-016

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Contract Manager

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Industrial, Agriculture and Water

Daryl Mills
Office Manager
Energy Efficiency Research Office

Martha Krebs, Ph. D.
PIER Research Director

Thom Kelly, Ph. D.
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ENERGY RESEARCH AND DEVELOPMENT DIVISION

Melissa Jones
Executive Director

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List of Companies Submitting Data
For Possible Participation in
OFFASES Project

- **Canaros**
- **Columbine**
- **Chevron Texaco**
- **Cooper & Brain**
- **Drilling & Production Co**
- **E&B Oil**
- **DECOR**
- **JP Oil**
- **St James Oil**
- **Seneca Oil**
- **Berry Petroleum**
- **Venoco**
- **BSI**
- **The TERMO Co**

HARSH GAS ANALYSIS

Midway Laboratory Inc.
Petroleum-Industrial-Environmental
315 Main Street P.O. Box 1151
Taft California 93268

State Certificate # 1396
Phone # (661) 765-2364
Fax # (661) 765-6920
E-Mail midlab@gtc.net

NATURAL GAS ANALYSIS

Rev 1/23/03

Customer: Drilling and Production
Attention: Darin Holden

Log #: 6963-3
Date Received: 9/9/2003
Date Completed: 9/9/2003
Report Date: 9/11/2003

Sample Description: Boiler Gas W/O Sweet

Analytical Parameter: Natural Gas Analysis

Constituent	Mole %	Wt. %	Lv. %
Oxygen	1.292	1.292	0.575
Nitrogen	4.675	4.093	2.251
Carbon Dioxide	52.622	72.386	61.882
Methane	40.066	20.091	34.062
Ethane	0.094	0.088	0.118
Propane	0.138	0.190	0.191
Iso-Butane	0.045	0.082	0.074
N-Butane	0.056	0.101	0.088
Iso-Pentane	0.068	0.153	0.125
N-Pentane	0.042	0.094	0.076
Hexanes Plus	0.259	0.744	0.559
Hydrogen Sulfide	0.644	0.686	0.463
Total	100.000	100.000	100.000

Hydrogen Sulfide, ppm 6439
Total Sulfur, as H2S ppm Not Requested

Physical Data

	dry	wet
BTU cu.ft. ideal	434.68	427.11
BTU cu.ft. real	435.93	428.35
BTU/lb. ideal	5156.15	5066.43
Sp. Gr. Ideal	1.0971	
Sp. Gr. Real	1.0998	

GPM	0.2212
z..factor	0.9971
F..factor	9795
Sp. Vol.	11.79

CHONS

	% by Wt.
% Carbon	36.010
% Hydrogen	5.289
% Oxygen	53.923
% Nitrogen	4.093
% Sulfur	0.686
Total	100.000

References
ASTM D 6228-98
ASTM D 1945-96
ASTM D 1946-94
ASTM D 3588-91
GPA 2145-00

Michael E. Mayfield
Laboratory Director
Midway Laboratory Inc.

HIGH BTU GAS ANALYSIS

Strata-Analysts GROUP

California Oil Producers Electric
301 E Ocean Ave #300
Long Beach, CA 90801

Date Sampled: August 26, 2004
Date Reported: August 26, 2004

Lab ID: 040676
File ID: 08-26-04 Cherry #6

Attention: Bob Fickes
CC: Orlando Toledo
CC:

Pressure: psig
Temperature: Deg F

Sample ID: Termo Cherry #6

GC/TCD (ASTM D1945, GPA 2261)

Analysis Results: (Detection Limit = 0.01)	Mole %		G/MCF	
OXYGEN	0.58			
NITROGEN	2.38			
CARBON DIOXIDE	2.63			
TOTAL INERTS:	*5.59*	(sum)		(sum)
METHANE	58.73			
ETHANE	6.05			
PROPANE	7.52		2.08	
iso-BUTANE	2.08	22.11	0.68	7.98
n-BUTANE	6.04		1.91	
iso-PENTANE	3.34	13.99	1.22	5.39
n-PENTANE	4.24		1.54	
HEXANE+	6.41		2.63	
Total	100.00			

Specific Gravity*	1.114			
			Dew Point:	Deg F.
Hydrogen Sulfide:		ppm(vol)		
			Water Content:	lbs/MMCF
Mercaptan Sulfur (GPA 2194)		ppm(vol)		
			HHV:	1763
			LHV:	1613
Gross BTU/ft^{3}*	1763	(dry gas)		
	1732	(Water Vapor Saturated)		

*=Calculated Result (ASTM D3588-91)

Reviewed by:

Bruce Barron

1842 East 29th St., Signal Hill, CA 90755
Tel: 562-426-0199 Fax: 562-426-5664
www.strata-analysts.com

ology, Inc.

E-mail pgtech@earthlink.net

4100 Burr Street
P.O. Box 80847
Bakersfield, CA 93380-0847
Telephone (661) 324-1317
Fax (661) 324-2746

Attention: Mr. Steve Dawson
CC: Mr. Mike Dixon
Nuevo Energy
57777 West Pacific Coast Hwy.
Ventura, CA 93001

Sampled:	4/1/2005
Submitted	4/1/2005
Analyzed:	4/5/2005
Reported:	4/8/2005

Gas Analysis by Chromotography - ASTM D 3588-91

Description: Turbine Fuel
Meter: 3610
Facility: ROSF

Lab No.: 050330-8
Pressure
Temperature

770 MCF/D

Component	Mole %	Weight %	G/MCF
Oxygen	ND	0.00	
Nitrogen	ND	0.00	
Carbon Dioxide	1.76	4.19	
Methane	91.45	79.27	
Ethane	1.81	2.94	
Propane	3.21	7.65	[illegible]
iso-Butane	0.35	1.10	[illegible]
n-Butane	1.05	3.30	[illegible]
iso-Pentane	0.11	0.43	[illegible]
n-Pentane	0.11	0.43	[illegible]
Hexanes Plus	0.15	0.70	[illegible]
Totals	**100.00**	**100.00**	[illegible]

Specific Volume, ft3/lb	20.50
Compressibility (Z) Factor	0.9974
Specific Gravity, Calculated	0.6390
GROSS BTU/ft3 Dry	1098.0
NET BTU/ft3 Dry	992.1

CHONS	Weight %
Carbon	[illegible]
Hydrogen	[illegible]
Oxygen	[illegible]
Nitrogen	[illegible]
Sulfur	[illegible]
F FACTOR @ 68 deg F dscf/MMBTU	8573
F FACTOR @ 60 deg F dscf/MMBTU	8548

Hydrogen Sulfide, ppm	Not Tested	Method	GC/FPD
Dew Point, deg F	Not Tested	Method	Bureau of Mines
Moisture, lbs H2O/MMCF	Not Tested	Method	Bureau of Mines

ND : None Detected

LOW BTU GAS ANALYSIS

Petroleum Technology, Inc.
E-mail pgtech@earthlink.net
4100 Burr Street
P.O. Box 80847
Bakersfield, CA 93380-0847
Telephone (661) 324-1317
Fax (661) 324-2745

Attention: Steve Dawson
CC: Mr. Mike Dixon
Nuevo Energy
57777 West Pacific Coast Hwy.
Ventura, CA 93001

Sampled: 4/1/2005
Submitted: 4/1/2005
Analyzed: 4/5/2005
Reported: 4/8/2005

Gas Analysis by Chromotography - ASTM D 3588-91

Description: CO2 Tail Gas
Meter:
Facility: ROSF

Lab No.: 050330-1
Pressure
Temperature

615mcf/D

Component	Mole %	Weight %	G/MCF
Oxygen	ND	0.00	
Nitrogen	0.42	0.28	
Carbon Dioxide	95.40	98.16	
Methane	4.18	1.57	
Ethane	ND	0.00	
Propane	ND	0.00	0.000
iso-Butane	ND	0.00	0.000
n-Butane	ND	0.00	0.000
iso-Pentane	ND	0.00	0.000
n-Pentane	ND	0.00	0.000
Hexanes Plus	ND	0.00	0.000
Totals	**100.00**	**100.00**	0.000

			CHONS	Weight %
Specific Volume, ft3/lb		8.87		
Compressibility (Z).Factor		0.9945		
Specific Gravity, Calculated		1.4768	Carbon	[illegible]
			Hydrogen	[illegible]
GROSS			Oxygen	[illegible]
BTU/ft3	Dry	42.2	Nitrogen	[illegible]
			Sulfur	[illegible]
			F FACTOR @ 68 deg F, dscf/MMBTU	30452
NET				
BTU/ft3	Dry	38.0		
			F FACTOR @ 60 deg F, dscf/MMBTU	30033

Hydrogen Sulfide, ppm	Not Tested	*Method*	GC/FPD
Dew Point, deg F	Not Tested	*Method*	Bureau of Mines
Moisture, lbs H2O/MMCF	Not Tested	*Method*	Bureau of Mines

ND : None Detected

MEDIUM BTU GAS ANALYSIS

Strata-Analysts GROUP

St. James Oil Company
1235 South Broadway
Los Angeles, CA 90015

Date Sampled: May 24, 2004
Date Reported: May 24, 2004

Lab ID: 040421
File ID: 05-24-04 Incoming Wells 1 & 4

Attention: Charles Sudderth
Victor Lopez

CC:

Pressure: psig
Temperature: Deg F.

Sample ID: St James
Incoming Wells 1 & 4

GC/TCD (ASTM D1945, GPA 2261)

Analysis Results: (Detection Limit = 0.01)	Mole %		G/MCF	
OXYGEN	0.00			
NITROGEN	0.00			
CARBON DIOXIDE	0.78			
TOTAL INERTS:	*0.78*	(sum)		(sum)
METHANE	72.80			
ETHANE	13.42			
PROPANE	7.49		2.07	
iso-BUTANE	1.25	5.51	0.41	1.90
n-BUTANE	2.17		0.69	
iso-PENTANE	0.63	2.09	0.23	0.80
n-PENTANE	0.53		0.19	
HEXANE+	0.93		0.38	
Total	100.00			

Specific Gravity*	0.794				
			Dew Point:		Deg F.
Hydrogen Sulfide:		ppm(vol)			
			Water Content:		lbs/MMCF
Mercaptan Sulfur:		ppm(vol)			
(GPA 2194)			HHV:	1363	
			LHV:	1239	
Gross BTU/ft^{3*}	1363	(dry gas)			
	1340	(Water Vapor Saturated)			

*=Calculated Result (ASTM D3588-91)

Reviewed by:

Bruce Barron

1842 East 29th St., Signal Hill, CA 90755
Tel: 562-426-0199 Fax: 562-426-5664
www.strata-analysts.com

Arnold Schwarzenegger
Governor

APPENDIX D
TECHNOLOGY TRANSFER

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Bob Fickes
California Oil Producers Electric Cooperative (COPE)

December 2008
CEC-500-02-016

Prepared By:
California Oil Producers Electric Cooperative
Bob Fickes
Long Beach, California 90802
Contract No. 500-02-016

Prepared For:
Public Interest Energy Research (PIER)
California Energy Commission

Paul Roggensack
Contract Manager

Pramod Kulkarni
Program Area Lead
Industrial, Agriculture and Water

Daryl Mills
Office Manager
Energy Efficiency Research Office

Martha Krebs, Ph. D.
PIER Research Director

Thom Kelly, Ph. D.
Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

Melissa Jones
Executive Director

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West Coast PTTC Workshop

Panel On

"Power Generation - Using Waste and Stranded Gas"

Tuesday, Nov. 22, 2005
Hyatt Valencia Conference Center,
24500 Town Center Drive, Valencia CA
Registration starts at 8:30 am

This workshop is intended to review opportunities and challenges in using distributed electric power generation from produced gas for reducing operating cost.

Co-Sponsored by: U.S. Department of Energy (DOE), University of Southern California (USC), California Independent Petroleum Association (CIPA), Western States Petroleum Association (WSPA), Independent Oil Producers' Agency (IOPA), State Lands Commission, Minerals Management Service (MMS), U.S. Department of Interior, Conservation Committee of California Oil & Gas Producers (CCCOGP), State of California, Department of Conservation, Division of Oil and Gas and Geothermal Resources (CADOGGR), Los Angeles Basin Section of SPE, San Joaquin Valley Section of SPE

8:30 AM	***Registration***
9:00	***Workshop Moderator-*** **Chris Hall,** Drilling and Production Company Invited Speakers: Richard C. Russell,St. James Oil Company — Rod Headley, Central California Power Egon Garthoffner , Oxy USA, Inc. — Peter Laehy, Pacific Energy Solutions Cliff Simonson, BSI — John Swanson, Capstone Trent Rosenlieb, The Termo Company — Rajesh Buch, Ingersoll Rand Energy Systems Jeevan Anand, Pacific Energy Resources — Edan Prabhu, Flex Energy Christopher Schmidt, Unico, Inc - Oil & Gas Division
	Part I - Considerations for buying and/or not buying self generating equipment. Payout expectations Operational and maintenance issues Self generation and selling power on the grid
	Part II - General Background – ***Speakers: Casper Zublin, Energy Options, Chris Hall, Drilling & Production Co., Bob Fickes, COPE*** Associated gas availability, current uses, quantification, quality and conditioning hurdles. Electrical power considerations and unique issues Utility Tariffs and Non-bypassable Charges Permits - Utility Interconnect , Air, and Construction Equipment Selection – systems design Types of prime movers available and selection reasons Service/Maintenance Issues. Equipment reliability Self Generating Incentive Program Site requirements Activity time line and cost outlines
12:00pm	***LUNCH***
1:00pm	***Part III -*** Presentation by Vendors: Internal Combustion Micro turbine generator External Combustion
	Part IV - Case Histories by Producers/Operators Examples of installations, lessons learned, how they are working
	Part V - Resources Availability Where to go for additional information and assistance
	Part VI - Panel Discussion – Q and A
4:30 PM	***ADJOURN***

The Flex-Microturbine® for Oilfield Gases

A Presentation to the IOGCC* Annual Meeting

Oklahoma City, October 18, 2004

22922 Tiagua, Mission Viejo CA 92692-1433

Phone: 949 380 489; FAX: 949 380 8407 email: [redacted]

* Logoless

FlexEnergy

Gas Comes with Oil

- Oilfields (and gas wells, and even coal mines) release gas
- Some of the gas is pipeline quality, some is not
- Gas quality is different from well to well, from time to time
- Some gas is so weak that it is not combustible
- Often, unless the gas is consumed, oil production will suffer
- Even flares are becoming harder to permit
- In the Bakersfield area of California, there is 200 million Btu of low Btu gas at below 100 Btu/scf available
- As part of the OFFGASES Project, COPE and FlexEnergy plan to run a Flex-Microturbine on the low Btu gas without any other fuel

FlexEnergy

What is the Flex?

- The Flex-Microturbine runs on waste gases or gasified solids and liquids
- Very low concentrations of gas are acceptable. A mixture with only 1.3 to 1.5% methane, or 13 to 15 Btu per scf will generate full power
- The Flex is adapted from the Capstone C30 microturbine. It uses a catalytic combustor and generates no NOx or CO; it is the cleanest means of power production
- It is highly fuel-flexible
- Each Flex generates 30 KW; multiple Flex-Microturbines can be laid out like machines in a laundromat

FlexEnergy

Projects and Progress

- Endurance Shop Tests of the Prototype have been completed; over 1,500 hours have been logged
- A Flex-Demonstration is running on 250 Btu gas from a digester in the Los Angeles area
- Another Demo is running on 120 Btu gas from wood
- A unit will soon run on 60 Btu gas (6% methane) from an oilfield near Bakersfield, CA
- Flex-turbine NOx emissions are extremely low, about 20 to 30 PPB; CO emissions are 5 to 30 ppm

FlexEnergy

A Primer on the Flex-Microturbine

- The Flex-Microturbine *first mixes air and fuel*, then compresses the two together
- The mixture is so weak that traditional combustion will not work, the Flex-Microturbine uses a catalytic combustor, derived from automotive catalytic converter technology
- Gas may be delivered at atmospheric pressure. No separate fuel compressor is required

FlexEnergy

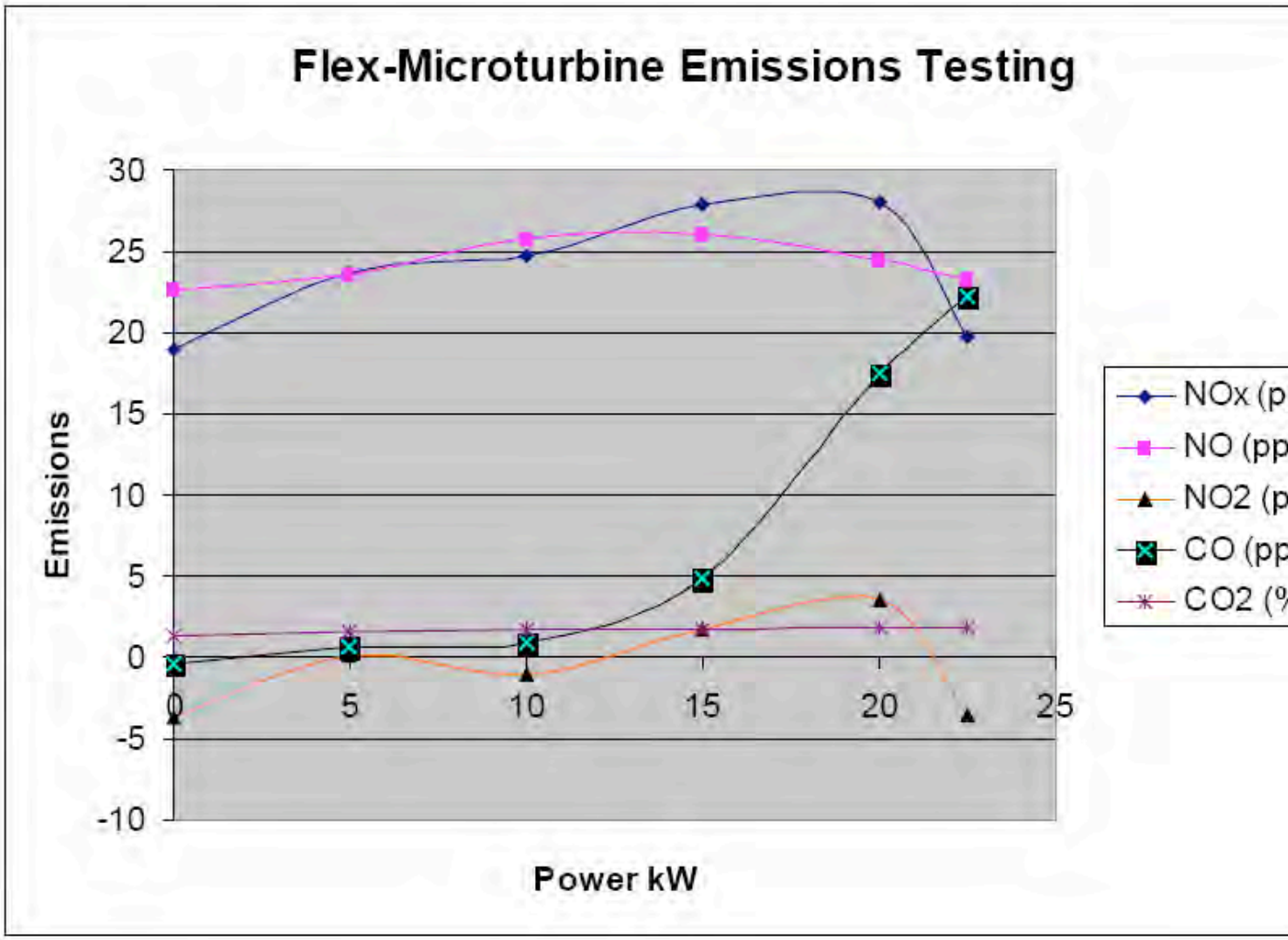
Why the Flex?

- Most turbines, fuel cells, IC engines, require at least 400 Btu gas, preferably higher
- The traditional Capstone microturbine is limited to fuels above 350 btu/cubic foot; others require much higher Btu fuel
- The Flex accepts any fuel, high or low Btu, dilutes it to 13 Btu, and consumes it to generate power…one size fits all

FlexEnergy

Potential Flex Applications

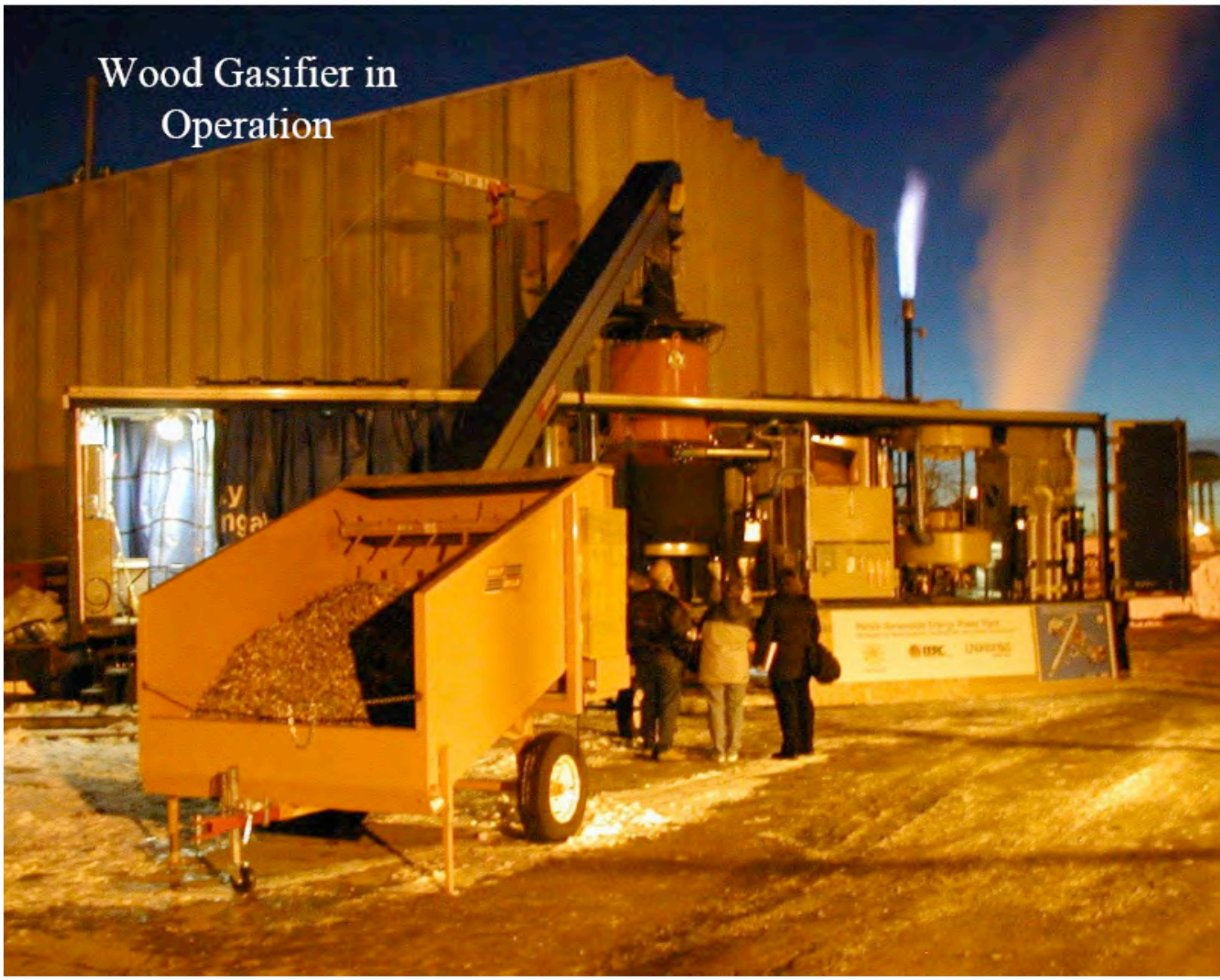
- Petroleum and gas drilling sites, coal mine vent gas, such as the OFFGASES Project
- Oilfield off-gases from production and refining operations
- Water treatment, landfills, sewage treatment
- Manure digesters from cattle, poultry, swine, farms (poultry litter can also be thermally gasified)
- Nutshells, orchard trimmings, wood waste, grain stalks, grain hulls, olive and cherry pits
- Gas from Compost Operations if it can be collected
- Low Energy Industrial vent gases: isopropyl alcohol vapor, hydrogen etc.

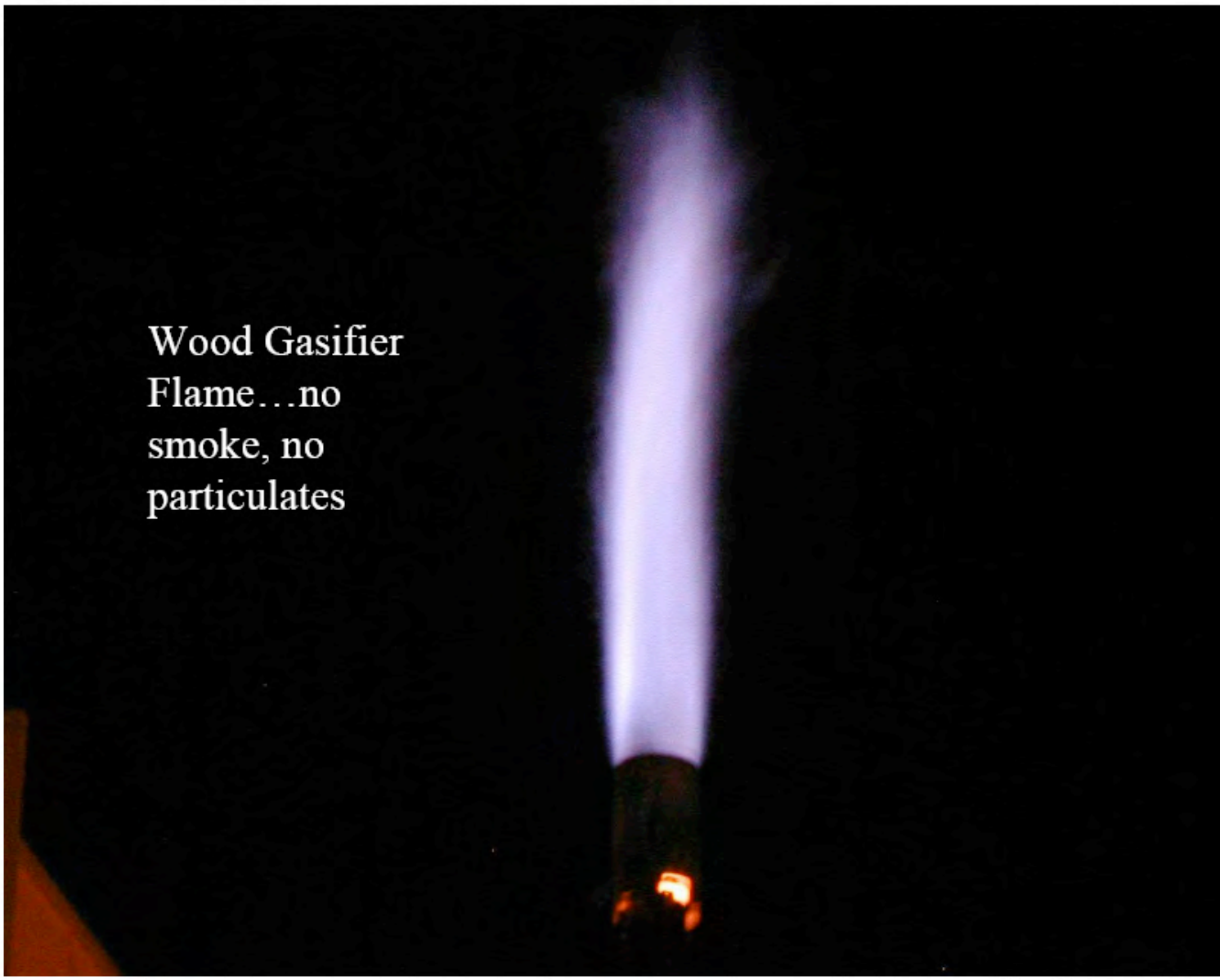

Flex-Microturbine Emissions Testing
Emissions
Power kW
30
25
20
15
10
5
0
-5
-10
0
5
10
15
20
25
NOx (p
NO (pp
NO2 (p
CO (pp
CO2 (%

FlexEnergy

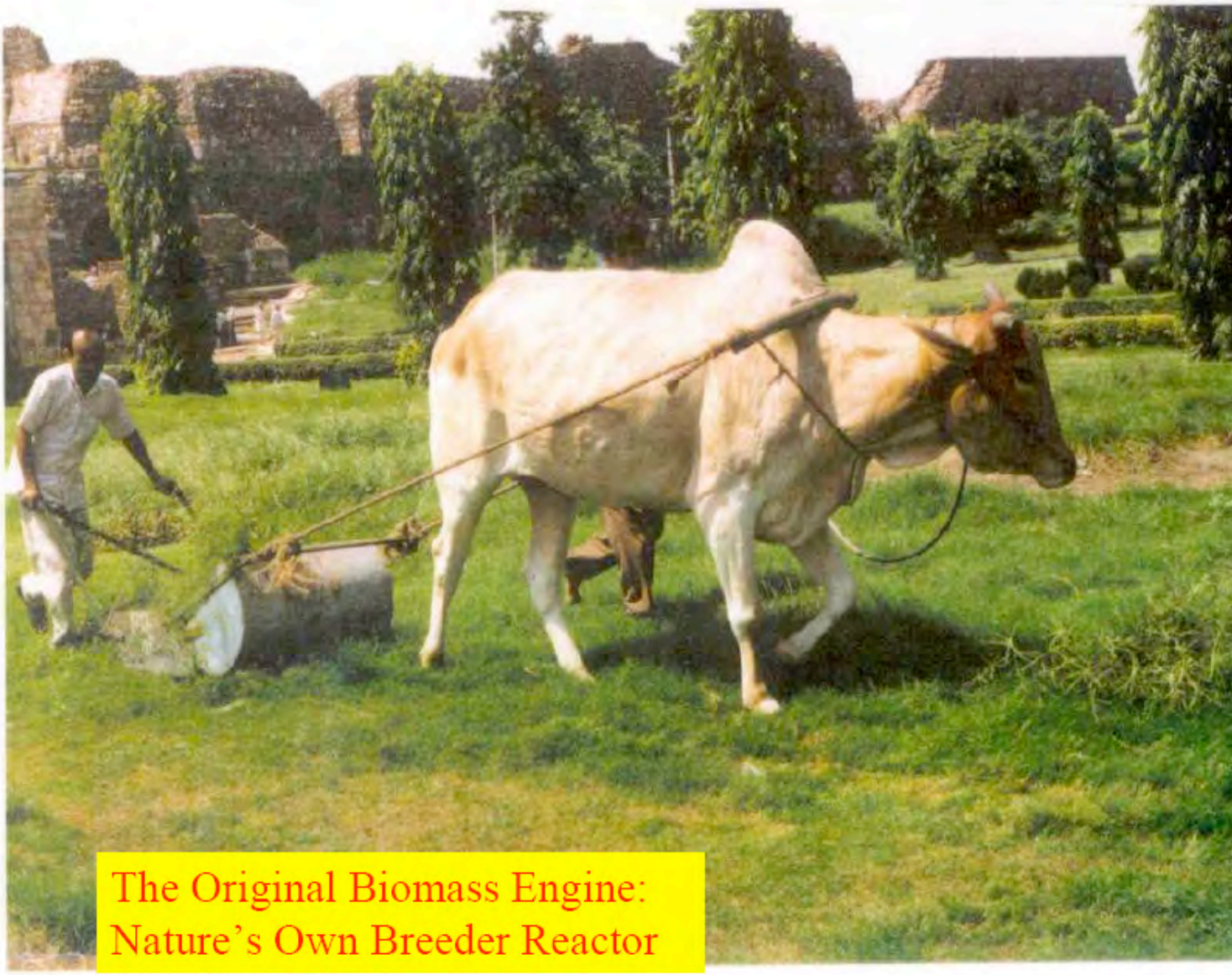
Where will the Flex make a Difference?

- If you have a site where low Btu gas is emitted or production is suppressed to prevent emission
- Credits for greenhouse gas reduction (Methane has a Global Warming Potential (GWP) of 23 (CO2 has a GWP of 1)


Wood Gasifier in
Operation


Wood Gasifier
Flame…no
smoke, no
particulates

Turbine
type in
ation:
d



The Original Biomass Engine:
Nature's Own Breeder Reactor

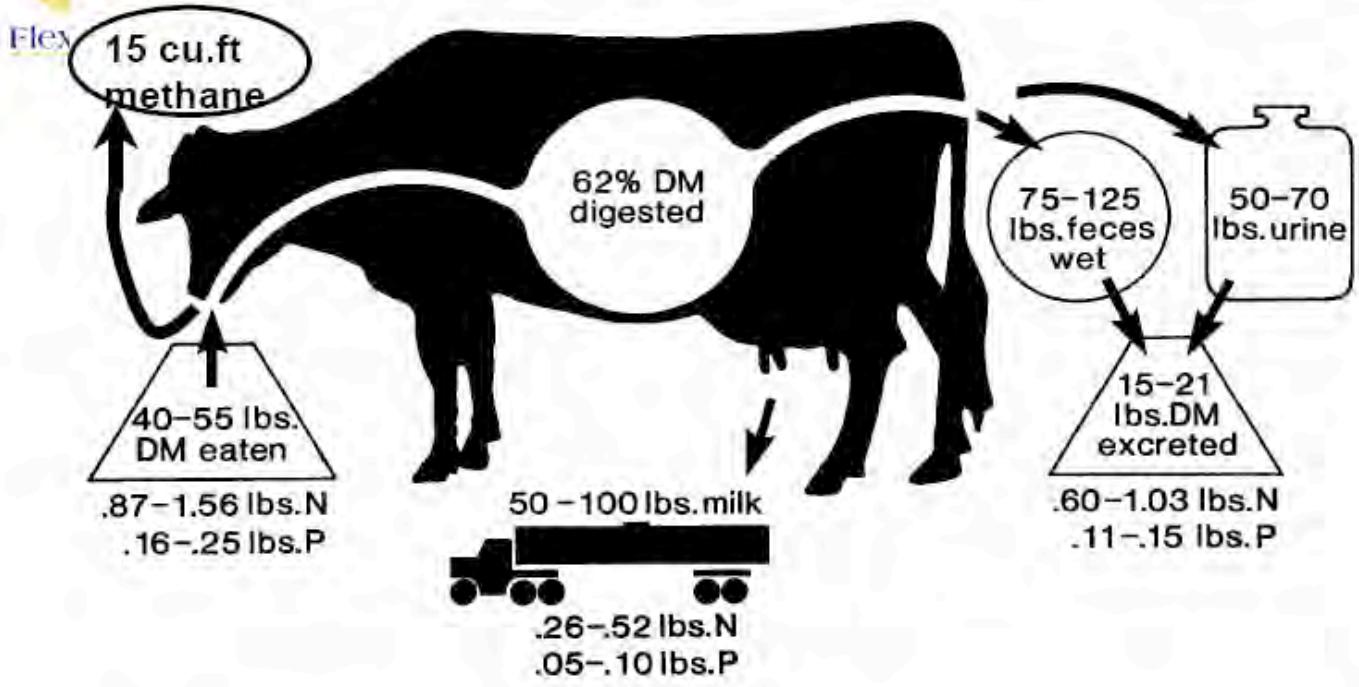
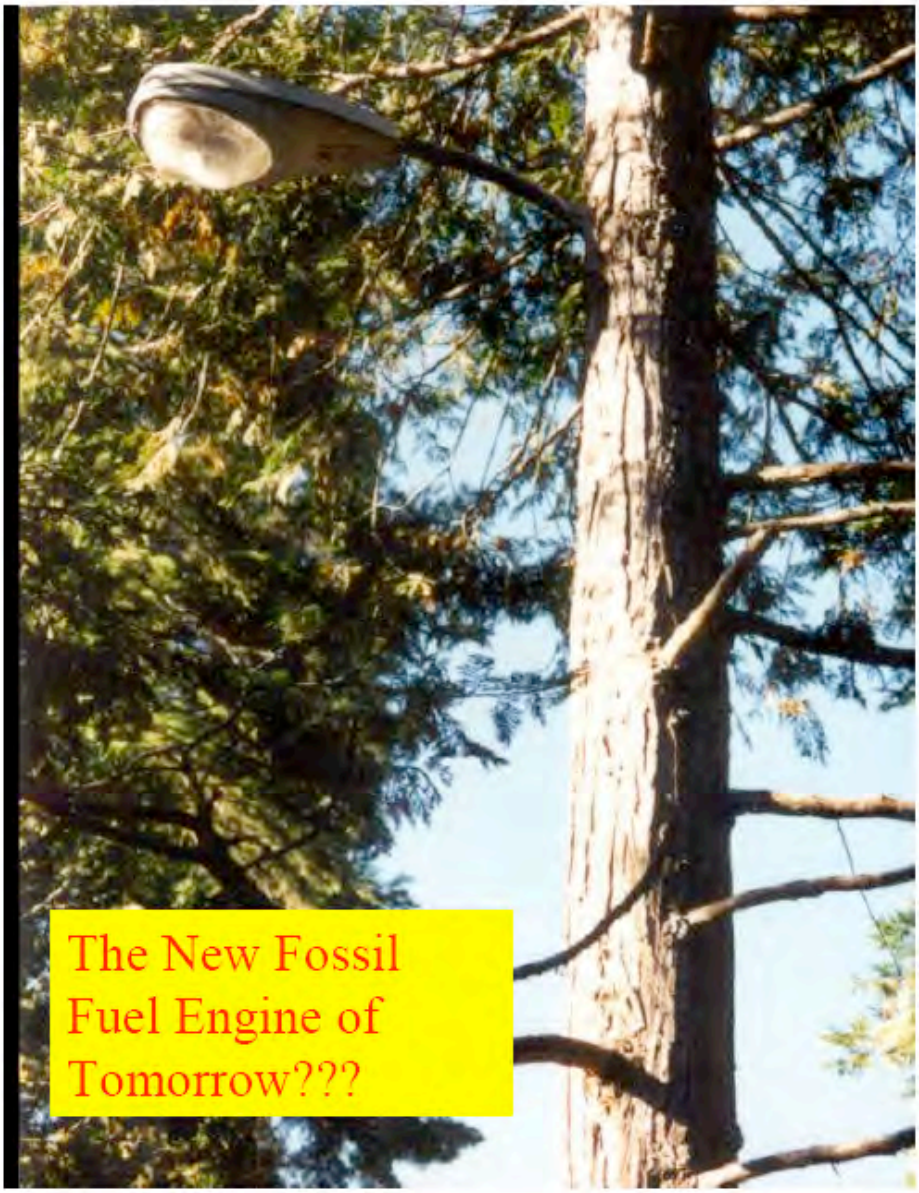


Figure 1. Daily input-output of dry matter (DM), nitrogen (N), and phosphorus (P) for a lactating cow producing 50 to 100 lbs of milk per day. Data from Table 1.

Could it be possible to capture enteric methane for power?

FlexEnergy



The New Fossil Fuel Engine of Tomorrow???

THOSE WHO KNOW, SHARING WHAT THEY KNOW, FOR MUTUAL BENEFIT

PTTC TECHNOLOGY CONNECTIONS

NEWS NETWORK

Technology—The Engine That Drives Oil And Gas Production

Petroleum Technology Transfer Council WWW.PTTC.ORG

Notes From The Director

2007 has been an interesting year—in Oklahoma where I live it is late July and average rainfall is 25% above normal and still not a single day above 100 °F. That doesn't mean the heat is not on. PTTC continues to adapt and make progress towards an industry-funded model that will ensure we're here for the long term. Two key elements to our transition are (1) the receipt of some DOE funding to assist with the transition and (2) the move towards an AAPG-managed PTTC. The latter would bring a lot of resources to the table that PTTC on its own could likely never develop. It's not a done deal, but AAPG and PTTC are working diligently to bring it to pass, with DOE's full support and hope for some continued federal involvement in the long term. So the message is— have faith and stick with us. It will be good.

One element that we're examining for the future is "**Knowledge Centers**." Read about them on page 2, then give us your feedback on priorities by completing the **Online Survey**. I promise that doing it online will be painless. If not online, do it through fax. Either way, it is your input that we need.

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Vol. 13, No. 2 July 2007

AAPG, PTTC Sign Letter of Intent

PRESS RELEASE JULY 2007

The American Association of Petroleum Geologists and the Petroleum Technology Transfer Council in early July signed a Letter of Intent for AAPG to assume management of PTTC activities.

AAPG is a professional scientific organization with over 31,000 members in 115 countries. Since 1994, PTTC, funded primarily by the U.S. Department of Energy with funds matched by the states and industry, has been a recognized force for transferring exploration and production technology to domestic U.S. producers. Serving industry locally through Regional Lead Organizations, typically at universities or geological surveys, PTTC's primary focus has been serving independents.

Last year, Congress declined to provide FY07 funding for many elements of the Department of Energy's natural gas and oil R&D program from which PTTC drew its federal funds. DOE ultimately provided $1 million of funding through September 2008 to help PTTC transition to a primarily industry-funded organization.

One likely result of the transition is realignment with AAPG's sections to realize synergy with their active volunteers.

PTTC's primary tool for transferring E&P technology is regional workshops, which are supplemented with a strong web presence, newsletters and other personal outreach. Using these tools, PTTC connects producers, the service sector, consultants, researchers and others with the data and technology information needed to spur technology application.

Topics addressed by PTTC activities have covered the full spectrum of E&P operations, including exploration, unconventional resources, enhanced recovery processes, imaging technology, drilling and completion, hydraulic fracturing and many others.

The agreement provides for a due-diligence period of 60 days after which, presuming positive negotiations, the transition to an AAPG-managed PTTC would occur.

For further information contact:

Larry Nation
AAPG Communications Director
800.364.2274, ext. 648

E. Lance Cole
PTTC Executive Director
918.241.5801

Meeting Alerts

Colorado O&G Association
Rocky Mountain Natural Gas Strategy Conference & Investment Forum
Aug. 13-15 Denver, CO
www.coga.org/pageinpage/conference.cfm

APTA/Midland College CO2 School
Aug. 21-24 Midland, TX
www.midland.edu/~ppdc/events

Summer NAPE
Aug. 23-24 Houston, TX
www.napeonline.com/home2.asp

AAPG Midcontinent Section Annual Meeting
Sep. 9-11 Wichita, KS
www.aapg.org/sections/midcontinent.cfm

AAPG Eastern Section Annual Meeting
Sep. 16-18 Lexington, KY
www.uky.edu/KGS/esaapg07/

Stripper Well Consortium Tech Transfer Meeting
Sep. 20 Roanoke, WV
www.energy.psu.edu/swc/

IOGCC Annual Meeting
Sep. 23-25 New Orleans, LA
www.iogcc.state.ok.us/events.html

SEG Annual Meeting
Sep. 23-28 San Antonio, TX
http://meeting.seg.org/

Louisiana O&G Association: Gulf Coast Prospect Expo
Sep. 25-26 Lafayette, LA
www.lioga.com/Events/EventsDisplay.asp?p1=239&p2=Y&p9=E&E=N

GCAGS Annual Convention
Oct. 21-23 Corpus Christi, TX
www.gcags.org/

Stripper Well Consortium Tech Transfer Meeting
Oct. 30 Wichita, KS
www.energy.psu.edu/swc/

Knowledge Centers—A Concept that PTTC Is Exploring

Just what is a knowledge center? The concept is simple. For a given topic, say hydraulic fracturing, PTTC would identify a few respected, unbiased individuals, universities or organizations that are recognized as leaders in the field. We listen to those experts, letting them help define what content needs to be captured within a knowledge center. We then retain them to develop the knowledge center and make information available through the Internet and workshops. It is not really research; it's gathering all that is relevant (as determined by experts). They are available only to those who "pay to play." Those willing to pay are a self-qualified audience—they are coming with a need and an application requiring services. This creates the incentive for vendors and service providers to provide funds to demonstrate their capabilities. Everybody wins: producers, vendors and service providers, PTTC and ultimately the country, as more domestic oil and gas is discovered and produced.

What would a knowledge center contain? Many elements are envisioned. To start, there would be a white paper that crisply summarizes the science, the remaining issues and the directions industry is pursuing to solve those issues. Hearing this from acknowledged experts will save days or weeks of digging for reliable information. There also would be case studies demonstrating how technology solved real world problems. Vendors and service providers would have a place to show how their solutions matched problems. A "links" section would enable users to quickly connect with those vendors. There would be an annotated bibliography directing individuals to the papers/articles publicly available that the experts considered to be seminal works. Active research consortia would be described along with their research thrusts and who to contact to get directly involved. A calendar would alert users to upcoming workshops across the country that were focused on the topic, or to proceedings from past workshops that might be available. Each year the experts would develop a top-notch workshop, which would be videotaped. Local workshops combining videotape and live presentations of regional case studies could be made available.

What will it take for the knowledge center concept to work?

- You the audience must prioritize the topics that PTTC pursues for knowledge centers. To that end, this article directs you to an online survey. In addition to the obvious prioritizing of topics, the number of people who actually respond to this survey will help PTTC assess the level of industry interest.
- Experts, those knowledgeable in the field, must agree to participate for compensation that a non-profit can afford. The reality is that participating experts will do so for reasons other than compensation.
- Vendors relevant to a topic must provide significant sponsorships. For this to happen, PTTC and the experts must present them with a "prospectus" of the knowledge center—a picture of what it will actually contain and what will happen within the knowledge center—and some indicator of industry interest and participation. Keep in mind that with a "self-qualified" audience it doesn't require thousands, but rather just a few hundred individuals, for sponsorship to be attractive for the service community.♦

Do PTTC A Favor—Complete this survey online at **www.pttc.org/knowledge_center_survey.htm**. It will save us time and money and allow us to analyze your input in real-time.

Survey - Your Priorities for Knowledge Center Topics

Industry's input needed: Help PTTC assess the feasibility of the Knowledge Center concept by identifying and prioritizing the topics you are interested in. Just a few minutes of thought in responding will deliver results to you. Thanks from PTTC.

Potential Knowledge Center Topics	Ranking (from 1 to 5)				
Why? Save days or weeks finding concisely organized technical information critical to performing your job. ***What is a knowledge center?*** A semi-virtual technology information resource center developed by those recognized as leaders in the field. Solutions are presented through the Internet and annual workshops.	Importance to You/Your Company? 1=low interest - 5=critical topic *(please circle your response for each item below)*				
Shale Gas Resource Development	1	2	3	4	5
Coalbed Methane Development & Operations	1	2	3	4	5
Recent Developments in Formation Evaluation and Logging	1	2	3	4	5
CO2 Flooding	1	2	3	4	5
Advances in Coiled Tubing or Microhole Drilling	1	2	3	4	5
Horizontal Drilling	1	2	3	4	5
Hydraulic Fracturing - Completion & Initial Stimulation	1	2	3	4	5
Wellbore Damage Removal and Well Restimulation	1	2	3	4	5
Wellbore Management (Extending Downhole Equipment Life)	1	2	3	4	5
Gas Well Deliquification	1	2	3	4	5
Affordable, Efficient Well & Field Automation	1	2	3	4	5
Produced Water Shut-off/Management	1	2	3	4	5

Is there a topic you'd like to see that is not listed? Suggest topics for PTTC.

_____

_____

_____

_____

Please fax response to PTTC (918.241.5728) *Thanks in advance for your input.*

Optional: Name: _____ Company: _____

Phone: _____ Email: _____

Proppant Flowback Treatments in Arkoma Basin Wells

XTO Energy Inc. (XTO) operates many conventional Arkoma Basin gas wells, typically completed in the late 1980s without fracture stimulation. In 2003 XTO began a fracture stimulation program, typically using a nitrified borate gel system to place proppant. Proppant flowback problems were common. Well cleanouts would restore production, but only temporarily. In 2006 XTO treated five wells with a proppant-flowback arresting (PFA) system.

The PFA service is a coiled-tubing deployed, single-trip, rigless intervention service that requires no isolation packers. Time and costs are lower than conventional workovers. The service treats the existing proppant in the near-wellbore region with a coating. After coating the grains, a consolidating agent forms a tacky film that creates bonds between grains that cure with time and temperature. Minimal conductivity loss is experienced. Curing of this one-component resin takes place slowly, which aids placement. The PFA service is implemented with pulsing technology, either fluidic oscillation or low-frequency pulsing, to enhance fluid flow and ensure penetration into the proppant pack.

The five wells in the 2006 program that XTO described had been requiring frequent wellbore cleanouts, costing $15,000 or more per cleanout. PFA treatments were performed in early 2006. Proppant flowback with associated production declines and down time has not been a problem since. Projected value added from reduced workover-cleanout expense and/or increased production varied from $210,000 to $400,000 per well per year.

Excerpted from "XTO Energy Extends Life of Arkansas Wells," Oil & Gas Journal, May 14, 2007, pp. 42-45.♦

IADC Planning Series of Books

Tackling the challenge of capturing the knowledge of experienced drillers that would be lost with the coming crew change in the O&G industry, the International Association of Drilling Contractors is planning a book series, as many as two dozen, spanning all aspects of drilling technology and operations. Plans are to publish five later this year or in early 2008. There are many books. What is different about this series? They will be peer-reviewed. The Book Committee, under the chairmanship of Leon Robinson, is looking for authors, co-authors, editors and reviewers. Interested? Contact Robinson at docleon@worldnet.att.net.

Excerpted from "IADC Book Committee Plans Legacy of Knowledge Before Greybeards Go Fishin'," Drilling/Contractor, January/ February 2007, p. 9.♦

Casing While Drilling (CWD) and Stage-Tool Cementing Combine to Resolve Piceance Basin Surface Casing Drilling Problems

The complex geology, dipping formation beds and fractured formations of the western Piceance Basin leads to "crooked hole" and "lost circulation" problems when drilling the surface hole. Surface casing is typically targeted at about 3,100 depth. Conventional drilling uses mud motors and low weight on bit. After drilling, hole conditions that can prevent getting surface casing to the desired depth can be encountered. Poor hole conditions also lead to poor cement jobs, requiring remedial workovers to achieve the cement return required by the Bureau of Land Management.

Sandridge Energy selected Weatherford's DwC (Drilling with Casing) service, combined with stage cementing of the surface casing. Results for a seven-well program were reported in this article, plus extended detail on some of the procedures involved. Bottom-line overall results were impressive compared to data evaluated for five wells that had been conventionally drilled. Documented improvements include:

- Reduced average overall drilling time by 2.72 days per well (21%),
- Reduced average surface-hole nonproductive time by three days per well (47%),
- Significantly reduced fluid loss with documented savings of $40,000 for one well,
- Reached desired surface casing depth in ALL WELLS,
- Achieved cement returns in ALL WELLS, and
- Reduced average deviation by 44%.

Excerpted from "Casing While Drilling and Stage-Tool Cementing Combined to Mitigate Downhole Conditions," World Oil, March 2007, pp. 59-64 available online at ***www.worldoil.com/magazine/MAGAZINE_DETAIL.asp?ART_ID=3141&MONTH_YEAR=Mar-2007.***♦

Deeper CT Drilling Growing in the U.S.

Coiled tubing (CT) drilling has been common in Canada, particularly at shallower depths. That experience is moving south to the U.S. Xtreme Coil Drilling Corp., with its Coil Over Top Drive rig, has been a driving force in the U.S. growth. Experience by multiple operators in multiple basins is building. Much of that experience is in deeper wells, which are made possible with Xtreme's rigs and the larger 3-1/2-inch CT developed for them by Tenaris Coiled Tubes. Further advancements may lead to even larger CT, which would further increase depths.

Following are some of the recent records with Xtreme rigs:

- Record depth: drilling for Encana in DJ Basin's Wattenberg field by XTC 200DT rig using 3-1/2-inch CT to depth of 8,125 ft
- Record drilling time: drilling for Anadarko in DJ Basin's Wattenberg Field by XTC 200DT rig—3.4 days spud to total depth; move to rig release 4.8 days
- Longest S Curve well: drilling for Encana in Piceance Basin reaching length of roughly 6,000 ft

Most recently, Xtreme delivered its first XTC 400 rig, operating for Encana in the Piceance Basin. This is a hybrid CT plus conventional drilling rig that has the same capabilities as a fit-for-purpose 14,000 ft conventional rig. CT can drill to near 10,000 feet, then one can use jointed drillpipe to approach 14,000.

Xtreme plans continued rapid growth, anticipating a fleet of 18 CT rigs by early 2008 with most scheduled for U.S. delivery.

Excerpted from "Coil Over Top Drive Rigs Carry Canadian Contractor to Onshore Drilling Records in U.S. Rockies," New Technology Magazine, June 2007, pp. 34-35; "New Larger Bore CT Drilling Beyond 7,000 Ft," Oil & Gas Journal, June 25, 2007, pp. 45-49; "Xtreme Operations Update and 2007 First Quarter Results" available online at ***www.xtremecoildrilling.com/news/releases/07-05-10xdcQ1.pdf.***♦

Developments in the Produced Water Arena

One element of DOE's produced water program focuses on produced water and the many issues associated with it. Several recent developments deserve notice.

Produced Water Management Information System (PWMIS) (http://web.evs.anl.gov/pwmis/). DOE's National Energy Technology Laboratory, in partnership with Argonne National Laboratory, has developed the web-based PWMIS. The new system offers critical information on current technologies and best practices, summaries of relevant state and Federal regulations and a decision tree for technology options to deal with produced water issues. PWMIS is an easily navigable web tool that consolidates all the required information in one location.

Desalination Unit. In a DOE-supported project Texas A&M University has developed a new technology to remove salts and minerals from brackish coproduced water, yielding safe drinking water. The project's mobile desalination unit can process as much as 238 bwpd. It enables one to re-use about 30 percent of a well's wastewater stream, reducing the volume and costs of salt water disposal. The technology has been licensed to GeoPure Water Technologies LLC to commercialize. *View further information in DOE's Techline online at www.netl.doe.gov/publications/press/2007/070720-Oil_and_Gas_Produced-Water.html.*

Guide to Management of Produced Water. The Interstate Oil & Gas Compact Commission (IOGCC) in cooperation with ALL Consulting has completed a comprehensive new guidebook to the current best management practices for produced water from conventional gas and oil operations. The guidebook, entitled A Guide to Practical Management of Produced Water from Onshore Oil & Gas Operations in the United States, is available through IOGCC's website (www.iogcc.state.ok.us/projects.aspx). The project also developed an online geographic information system (GIS)-based analysis tool to help producers understand watershed-related regulations and permits and calculate the impacts of produced water in specific areas according to various oil and gas field development scenarios. The online guidebook and GIS tools will help regulatory agencies devise more effective regulations to make water management easier while still maintaining environmental protection.

DOE Receives AAPG's Corporate Award for Excellence in Environmental Stewardship

The American Association of Petroleum Geologists (AAPG) recently recognized DOE for its work in a network of regional carbon sequestration partnerships by selecting them for their "Corporate Award for Excellence in Environmental Stewardship." Nearly 350 organizations in 41 U.S. states, four Canadian provinces and three Indian nations are involved. A two-year characterization phase identified more than 3,500 billion tons of potential CO_2 storage capacity in geologic formations. The partnerships are currently working to implement 25 geologic sequestration tests.

View further information in DOE's Techline online at www.fe.doe.gov/news/techlines/2007/07026-DOE_Earns_Environmental_Award.html.

Closed-Loop Drilling: One Operator's Experience in NM

Drilling pits are an issue in New Mexico. Although perceived as being more costly than traditional pits, that is not necessarily so. Cimarex Energy Co. described their experience using an engineered on-site drilling waste treatment system on nearly 40 wells in Lea and Eddy Counties, New Mexico. Cimarex found that the average cost of using a pit and hauling the waste elsewhere for disposal is about 45% more compared to following the same process without a reserve pit. When burying the waste on-site, costs are about 24% higher when using a reserve pit. Cuttings volumes are significantly less, some 60 to 70% less. To top it off, the footprint of the drilling operation is reduced.

Excerpted from "Closed-Loop Drilling System: A Viable Alternative to Reserve Waste Pits," World Oil, December 2006, pp. 41-48 available online at www.worldoil.com/magazine/MAGAZINE_DETAIL.asp?ART_ID=3053&MONTH_YEAR=Dec-2006.

SEQURE™ Well Finding Technology

The SEQURE well finding technology, developed by NETL researchers in partnership with Apogee Scientific, Inc. (Englewood, Colo.), Fugro Airborne Surveys (Mississauga, Ontario, Canada) and LaSen, Inc. (Las Cruces, N.M.), employs magnetic and methane sensors deployed on helicopters to accurately locate abandoned and leaking wells. Finding these wells is valuable for secondary and tertiary recovery projects, but it is absolutely critical in future CO2 sequestration projects. SEQURE, along with two other technologies developed in DOE-supported R&D projects, received an R&D 100 Award from *R&D Magazine* for 2007.

For more information, view DOE's TechLine at www.fe.doe.gov/news/techlines/2007/07058-FE_Technologies_Win_Awards.html.

Green Completions in Fort Worth Basin Attractive for Devon

During a May 2007 EPA Natural Gas STAR workshop, Devon Energy Corp. shared their experience with reduced-emission or "green" completion practices in their Fort Worth Basin operations. With conventional practices, a well is flowed back to frac tanks until clean up is completed. Tubing is then snubbed in the hole while venting gas to atmosphere. Gas during required open flow potential tests is also vented to atmosphere. With reduced-emission completions, a temporary flowline and meter run is on location during completion. The well is flowed back to frac tanks until gas is encountered, at which time the well is turned to sales and revenue realized during further cleanup, snubbing and testing. In their Fort Worth Basin operations Devon's incremental costs are about $6,000 per well—but the incremental revenue from sale of captured gas is more than 10 times that. The work environment is safer and wells can be cleaned up longer. Since starting the practice in March 2004 through 2006, Devon had captured and sold about 3.7 Bcf of natural gas, realizing about $20 million in profits.

For more information, view Devon's presentation online at www.epa.gov/gasstar/workshops/collegestation-may2007/7-completions.pdf.

EPA's Natural Gas STAR Program

Aug. 21-22	Long Beach, CA	Producer Tech Transfer Meeting
Sep. 11	Glenwood Springs, CO	Producer Tech Transfer Meeting
Sep. 13	Durango, CO	Producer Tech Transfer Meeting
Oct. 23-24	Houston, TX	Annual Implementation Meeting

Recommended Practices *Check them out - make or save $ and protect the environment*

www.epa.gov/gasstar/

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» Networking events
» Student and young professional activities

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THUMS production facilities in Long Beach, CA, designed to blend in with coastal community. Photo courtesy of Occidental Petroleum Corporation.

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www.spe.org/atce

12-CD Set of DOE's Unconventional Gas Research Data

During the 1980s and 1990s DOE invested about $225 million in unconventional gas research. This research, or advances spawned by it, contributed greatly to technologies widely employed today in unconventional gas development. The archive, prepared in response to increased requests from industry for reports stored at NETL, includes nearly 1,400 documents on twelve CDs: four related to eastern gas shales, three related to western gas sands and one each related to methane from coal seams, methane hydrates, deep source gas and secondary gas recovery. Reports and proceedings covering the unconventional gas R&D program in general are included on a final CD.

*To order the 12-CD set, please visit the NETL CD-DVD ordering system (**www.netl.doe.gov/publications/cdordering.html**) and request the Archive of Unconventional Gas Research Data.*

Pre-Drill Seismic Technology for Deep Wells

Conventional seismic imaging and attribute analysis becomes less reliable the deeper the target. Rock Solid Images has developed, in a DOE-supported project, an approach that improves pre-drill diagnostics for deep reservoirs using a set of independent indicators known as seismic attenuation attributes. Essentially, the degree of attenuation is used to track the amount of gas or oil in the reservoir, and combined with conventional seismic analysis techniques, these attenuation attributes can effectively confirm or disprove the presence of oil or gas at depth.

The modeling software was tested offshore Norway where conventional seismic attribute analysis indicated possible hydrocarbons beneath a well drilled to 14,000 feet. Through rigorous forward modeling, using available log and seismic data, Rock Solid Images found that the anomaly was caused by a marked change in rock type, rather than oil or gas in the reservoir. Drilling another well was avoided. The modeling software has also been successfully tested in the deep Gulf of Mexico and offshore West Africa. It is commercially available through Rock Solid Images' iMOSS software package and has been adopted and developed for internal use by several major oil companies.

*For further information, view DOE's Techline at **www.netl.doe.gov/publications/press/2007/07051-Seismic_Technology_Goes_Commercial.html**.*

Stripper Well Consortium Makes 10 Project Awards

Following its spring meeting in New York, the Stripper Well Consortium (SWC) evaluated the received proposals and has subsequently made awards for 10 projects, committing over $1.16 million of SWC funding for work to be performed between August 1, 2007 and July 31, 2008. Projects address needs for both stripper oil and natural gas wells. Some projects are follow-on work to earlier SWC projects, while many are new. Some of the new projects are:

- *Low Cost, Stripper Well Booster Compressor* by Combined Heat and Power, Inc.
- *Novel Low Rate, Electric Plunger Pump System* by Impact Technologies LLC
- *Hybrid Casing Plunger for Multiple Zone Stripper Wells* by PAAL LLC Casing Plungers
- *New Class of Novel Paraffin Inhibitors* by RTA Systems, Inc.
- *Low Cost, 2-Tower Micro Scale N_2 Rejection System* by University of Kansas Research Center

*Readers are encouraged to review details of all projects, which are available on the SWC's website (**www.energy.psu.edu/swc/projects.html**).*

New Approach Brings High-End Modeling Software to the PC

In a DOE-supported project, Texas A&M University has adapted sophisticated computer modeling to the PC, using "Generalized Travel Time Inversion" technology. Cost and time savings coupled with the streamlined model and accessible PC-based tools make the technology feasible for a much broader audience.

Reservoir characterization and subsequent simulation can identify unswept regions in mature fields. "History matching" to calibrate the model is essential and tracer tests provide key data that must be modeled during history matching. In the Texas A&M project, researchers developed a novel, computerized method for rapidly interpreting field tracer tests. The new method integrates computer simulations with history matching techniques, allowing scientists to design tracer tests and interpret the data using practical PC-based software—a process that is much faster than conventional history matching.

The developed technology has already been adopted by two companies. As a result of widespread interest in advancing this technology, A&M researchers have an ongoing industry research and development consortium funded by eight oil production and service companies and won a grant from the National Science Foundation.

*For more information, view DOE's Techline at **www.fe.doe.gov/news/techlines/2007/07035-PC_Tools_Boost_Oil_Recovery.html**.*

NPC Presents "Energy" Study to DOE Secretary Bodman

Culminating a 22-month study effort, the National Petroleum Council presented its report, Facing the Hard Truths About Energy, to DOE Secretary Bodman on July 18. More than 350 expert participants contributed. Risks and challenges to a secure and reliable energy future were identified and strategies and recommendations were made. The NPC study conveyed multiple recommendations regarding R&D, which provides both technology for application and training for the future workforce.

- For enhanced oil recovery (EOR), support regulatory streamlining and R&D programs for marginal wells and expedite permitting of EOR projects, pipelines and associated infrastructure.
- For O&G resources affected by access restrictions, conduct national and regional basin-oriented resource and market assessments and use technology and operational advancements to allow environmentally responsible development of high potential onshore and offshore areas currently restricted by moratoria or access limitations.
- For unconventional O&G production, accelerate oil shale and oil sands R&D and leasing and accelerate unconventional natural gas leasing and development
- To expand R&D opportunities to support long-term study goals, review the current DOE R&D portfolio to refocus spending on innovative, applied research in areas such as EOR, unconventional oil and natural gas, biofuels, nuclear energy, coal-to-fuels and carbon capture and sequestration.

*Excerpted from Executive Summary (available online at **www.fe.doe.gov/programs/oil-gas/advisorycommittees/facing_hard_truths_execsumm.pdf**) of National Petroleum Council Report: Facing the Hard Truths About Energy, delivered to Secretary of Energy Bodman on July 18, 2007.*

The Digital Revolution: Archive, Organize and Deliver

Traditionally, public oil and gas databases in the Appalachian basin have contained various parameters associated with site specific well locations, including tops, thicknesses, treated intervals, initial well test and pressure and production histories. More recently, individual reservoir data were compiled on a field scale for oil (TORIS) and gas fields (Gas Atlas). Recent effort compiled a variety of other data types (stratigraphy, structure, seismic, petrology, geochemistry and gas production) for the Trenton-Black River trend.

Basin-wide databases created during recent research projects include: digital maps, cross sections and other illustrations that were either works in progress or finished versions in reports and slides used for presentations. References from the literature and lab data generated during the projects also are included in this "new generation-style" database, one that captures in digital form all aspects of previous work as well as this new information (as an example, see page 7—12-CD set of DOE's unconventional gas research data).

In a recent Appalachian Region workshop, those involved in developing and delivering data described the "digital" systems and resources available for their state. These offerings are dynamic, so an update like this has great value for those operating in the region.

Speakers representing the Pennsylvania Geologic Survey (PGS) described and demo'd (1) the WIS (Well Information System) and (2) PA*IRIS (Pennsylvania Internet Record Imaging System). WIS originally was for internal use only, but evolved into a system that can be used by visitors to the PGS offices. Survey personnel help the visitors log on to find information on individual wells. PA*IRIS was developed to enable industry to access well records from their offices. Essentially, the PGS scanned everything in their files and put it into this system. An expensive software system is required to view the information, so the PGS charges each subscriber a one-time $5,000 fee, plus $500 for annual maintenance.

Originally PA*IRIS included scanned location plats, the completion record (drillers' log) and perhaps a plugging affidavit, but it has evolved since '99 to link to WIS, so more detailed information on an individual well can be accessed. This includes interpreted information, such as log tops picked by staff geologists, plus lists of available logs, lists of "canned" reports with data in spreadsheets and a production module that allows the user to gather production data. ArcReader allows users to view tiff images of oil and gas base maps.

The PGS is planning several new products that will become part of PA*IRIS. This includes 7.5 minute topo maps with well locations, the ability to view several layers, download capability, interactive tools, etc. They plan 10-15 interactive layers that can be turned on or off, with print capability.

Staff from the Ohio Geologic Survey described and demo'd POGO, the Production of Oil & Gas in Ohio database that is updated annually; the digital map series; bedrock geology, on CD or online; and the interactive map series. Most of the time was spent describing the interactive map series, which includes the oil and gas maps in combination with topographic maps, aerial photos, roads and streams, etc. A print layout feature with scaling options allows you to create a PDF.

Searches can be made on many parameters, but most begin with the state permit number. Ohio has one file, one folder per well in their system, whereas Pennsylvania has separate files for the plats, well record, plugging record, etc. The Ohio system allows a user to cut and paste well data and create their own shape files. They also have a query string option, allowing a user multiple choices to add to the query string before the search is executed and the data are assembled in a table or on a map.

In New York there is ESOGIS (Empire State Oil & Gas Information System). Early punch card and tape systems eventually evolved into the online system of today. Their goal in NY was to make all subsurface data and information, including all of their reservoir studies, available online. This includes slides of numerous talks presenting results of research. To use the site, one first must create an account, then log in. Creating an account allows one to create different project files and then to add data to these files. There is no limit to the number of wells that you can download, but there is a one minute time limit on the downloads. A project manager feature allows one to create a project, add wells, tailor the data, display and download the data. Scanned images of well records, logs, etc. are available, as are production data. There is also a virtual core library, where one can look at core photos or core images. NYSERDA reports are also available there. Subscriptions range from $2,500 to $25,000, depending on which of five levels one chooses.

Staff from the West Virginia Geologic Survey (WVGS) described their (1) oil and gas database and (2) a current project to assemble from a variety of sources all data on five tight gas plays and deliver the data online. Current online services include "pipeline," a subscription service that allows users to access data on individual wells; production summaries, where queries can be made by well, by county or by years; e-logs, as scanned images in tiff files; focused datasets, mainly from project work, like Trenton-Black River, coal bed methane, etc; and the IMS site, which is hosted by the WVGS. The idea in the DOE-supported Log Scan project is to find every piece of data on five tight gas plays in two states, organize the data into a database and delivery it to users online. This data is currently widely scattered among offices and even within offices.

Demonstrating their commitment to the digital world, the Kentucky Geologic Survey has taken a bold step of closing their oil and gas record room (open by appointment only) and replaced it with a system that can display everything in that room on a user's computer. To do this, the user needs to download and install a free web browser plug in. No fees are required and no subscription service is necessary.

Those looking for data should not forget Google. Its searches not only lead one to the resources within geological surveys and state agencies, but there can be other sources. When one finds a resource of value, bookmark it and it's easy to go there again.

Appalachian Workshop

Core and Sample Analysis and Interpretation

September 2007 (TBD)
Pittsburgh, PA.

For information contact: 304.293.2867 x 5443, for date and details, watch the Appalachian Region calendar at: **www.pttc.org/appalachian/appalachian_calendar.htm**

Basin Analysis and Petroleum System Characterization and Modeling, Interior Salt Basins, Central and Eastern Gulf of Mexico

By Ernie Mancini and Don Goddard, University of Alabama and Louisiana State University

The University of Alabama and Louisiana State University have undertaken a cooperative five-year, two-phase fundamental research project involving sedimentary basin analysis and petroleum system characterization and modeling of the North Louisiana Salt Basin and Mississippi Interior Salt Basin. According to the United States Geological Survey, the hydrocarbon volume of these basins ranks them in the top 8% of the most petroliferous basins of the world. Phase 1 work focused on data compilation, determination of the tectonic, depositional, burial and thermal maturation histories, basin modeling and petroleum system identification for the North Louisiana Salt Basin; comparison of the geohistory of the North Louisiana Salt Basin to that of the Mississippi Interior Salt Basin and assessment of the undiscovered and underdeveloped reservoirs of the North Louisiana Salt Basin. Phase 2 work focuses on characterization and modeling of the Upper Jurassic Smackover petroleum system, characterization and modeling of other Mesozoic petroleum systems and refinement of the assessment of the undiscovered and underdeveloped reservoirs of the North Louisiana Salt Basin.

Three active petroleum source rocks (Oxfordian, Albian and Cenomanian-Turonian) have been reported from the onshore north central and northeastern Gulf of Mexico area. Based on the assessment of potential petroleum source rocks in the North Louisiana Salt Basin, only the Upper Jurassic (Oxfordian) Smackover lime mudstone beds were determined to be an effective regional petroleum source rock in this basin. The components of the Smackover petroleum system in the North Louisiana Salt Basin include the following: (1) the underburden and overburden strata include pre-rift, syn-rift and postrift deposits, which are a result of their rift-related geohistory; (2) organic rich and laminated Smackover lime mudstone beds are the petroleum source rocks; (3) petroleum reservoir rocks include

Figure 1. Location map of interior salt basins and subbasins in the north central and northeastern Gulf of Mexico area.

Jurassic, Cretaceous and Tertiary siliciclastic and carbonate strata; (4) petroleum seal rocks are Jurassic, Cretaceous and Tertiary anhydrite and shale beds; and (5) structural or combination traps characterize the basin with movement of the Jurassic Louann Salt also producing a complex array of structures that serve as petroleum traps. These structures include peripheral salt ridges; low relief salt pillows, salt anticlines and turtle structures; and piercement domes. From burial history and thermal maturation history profiles for wells in the North Louisiana Salt Basin, hydrocarbon generation and maturation trends have been observed.

Initiation of oil and associated gas was at a vitrinite reflectance (Ro) level of 0.55% and the commencement of essentially only thermogenic secondary, non-associated gas generation was at a Ro level of 1.3%. Cessation of thermogenic gas generation was at a Ro level of 4.0%. The generation of hydrocarbons from Smackover lime mudstone beds was initiated at 6,000 to 8,500 feet during the Early Cretaceous and continued into the Tertiary. Hydrocarbon expulsion from Smackover source rocks began during the Early Cretaceous and continued into the Tertiary. Commencement of oil expulsion began first in the southern (downdip) portion of these basins in the Early Cretaceous and peaked in the late Early Cretaceous. Smackover lateral hydrocarbon migration was probably of an intermediate range (80 km or 50 mi). Hydrocarbon migration into overlying strata was probably facilitated by vertical migration along faults.

The Bossier Shale has been identified as a potential Mesozoic petroleum source rock in the North Louisiana Salt Basin. Phase 2 work on characterizing these shale beds using thermal maturation history has been initiated with completion expected in early 2008.

PTTC workshops transferring Phase I insights to industry were held in Tuscaloosa, Alabama and Shreveport, Louisiana in spring 2007. Contact Bennett Bearden, Alabama (email bbearden@geo.ua.edu) or Don Goddard, Louisiana (email dgoddo1@lsu.edu) for further information about these workshops. There is other information about the research project and its reports online (link reports online to www.netl.doe.gov/technologies/oil-gas/Petroleum/projects/EP/Explor_Tech/15395UofAL.htm). Future workshops on later findings and insights are anticipated.♦

Louisiana O&G Association: Gulf Coast Prospect Expo

Sep. 25-26, Lafayette, LA

For more information visit:
www.lioga.com/Events/EventsDisplay.asp?p1=239&p2=Y&p9=E&E=N

Shallow Gas in the Michigan Basin

By Dr. William B. Harrison, III, Professor Emeritus, Michigan Geological Repository for Research and Education, Department of Geosciences, Western Michigan University, Kalamazoo, MI.

Shallow gas production is significant from the Michigan Basin. Approximately 40% of Michigan's gas production is shallow (<1500 feet). Total cumulative Michigan gas production exceeds 6.5 TCF, with Antrim Shale production at approximately 2.5 TCF. All other shallow formations have produced about 250 BCF.

Over 1200 wells have shown commercial production from less than 1000 feet deep and nearly 5200 wells produce gas from less than 1500 feet depth. About 91 percent of the shallow gas in Michigan is produced from the Upper Devonian Antrim Black Shale. Most of the 2.5 TCF of gas produced from the Antrim around the Basin's northern margin is biogenic in origin. The Antrim Shale in this area has seen low thermal maturation (Ro approximately 0.6). The presence of an extensive natural fracture network is the key to commercial production. Although there had been occasional Antrim producing wells since 1940, the recent development began in the late 1980s as a result of new technology, access to underutilized Silurian Niagaran Reef well infrastructure, and a federal non-conventional fuels tax credit (section 29). To date, the Antrim Shale in Northern Michigan, has produced over 2.5 TCF of gas from over 9000 wells. Production in 2006 was nearly 140 BCF. The Antrim Shale is a classic black shale that produces natural gas by desorption processes into a complex network of fractures. The distribution of high total organic carbon and natural fractures are keys to good productivity. This play, mainly in north-central Lower Michigan, has been developed through the use of vertical wells. The abundance of fractures in the primary development area makes vertical wells effective. Initial well spacing was on 40-acre units; unit size was increased to 80-acre units in 1995. Today some operators even use 160-acre units. Horizontal drilling has not become widely used in the Antrim Shale play. Few horizontal wells have performed significantly better than vertical wells.

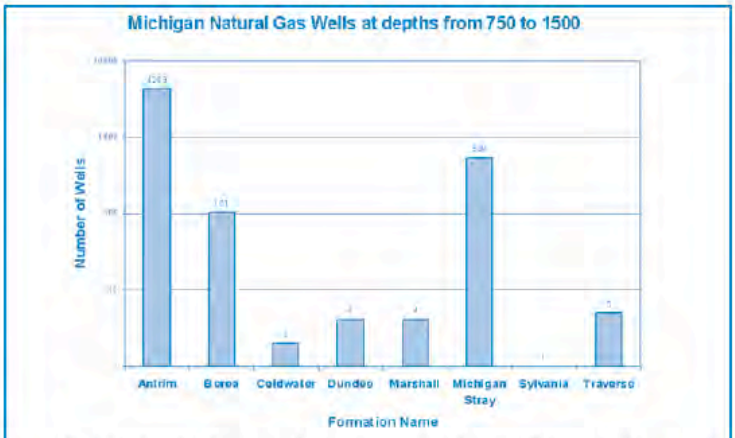


Figure 2. Distribution of Michigan natural gas wells by geologic formation. Data compiled from records of Michigan Geological Survey.

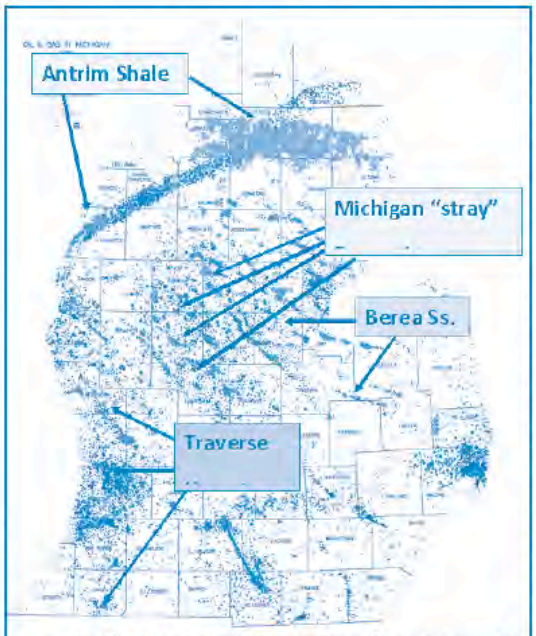


Figure 1. Modified from Michigan Geological Survey Map online www.deq.state.mi.us/documents/deq-ogs-gimdl-GGMOG05.pdf.

Shallow gas is produced from Devonian, Mississippian, Pennsylvanian and even sporadically from the Pleistocene Glacial Drift. Most other formations in the Michigan Basin have produced only small amounts of gas from shallow depths. Mississippian sandstones of the Michigan Formation and the Berea Sandstone have small amounts of commercial production. The Michigan Formation "Stray" Sandstone has been the most productive, with wells in seven different fields. The largest of these fields, Shaver Field in Gratiot County, produced over 11 BCF of gas before being converted to gas storage.

Middle Devonian carbonates of the Traverse Limestone have limited gas production from a few shallow conventional reservoirs, often associated with oil production. Gas-oil ratios are generally low (typically less than 5000). Historically much of the associated gas from these reservoirs was flared and accurate records of total gas production are poor.

Very limited gas production is also known from the Mississippian Marshall and Parma Sandstones, the Pennsylvanian Saginaw Formation and the Pleistocene Glacial Drift. Although the production of shallow gas from the Michigan Basin is dominated by the unconventional Upper Devonian Antrim Shale gas play, there are several other shallow conventional-type plays that should not be overlooked. If these other horizons were exploited with the intensity of the Antrim Shale development, other significant gas reserves may be found in the Michigan Basin.♦

Cellular geomodel for a giant gas field, Hugoton, Midcontinent, U.S.A.

Martin K. Dubois, Alan P. Byrnes, Saibal Bhattacharya, Geoffrey C. Bohling and John H. Doveton, Kansas Geological Survey

The Hugoton geomodel provides a comprehensive lithologic and petrophysical view of a mature giant Permian gas system, the 70-year-old Hugoton Field, which is the largest gas field in North America. Fine-scale cellular models are particularly important for modeling thin-layered, differentially depleted reservoir systems (Hugoton) and methods used in building the model demonstrate the construction of a cellular petrophysical model for a giant field. The study also illustrates the benefits of pooling proprietary geologic and engineering data in settings with multiple operators. Both the knowledge gained and the techniques and workflow employed have implications for understanding and modeling similar reservoir systems worldwide. As giant fields mature, high-resolution modeling at the full-field scale in data-rich environments will become increasingly important and the Hugoton model is a large-scale example for developing such models.

Building an accurate static model for the entire Hugoton field (Hugoton and Panoma in Kansas and Guymon-Hugoton in Oklahoma) was the primary objective of a 2-1/2 year collaborative project sponsored by ten industry partners and the State of Kansas through the Kansas Geological Survey. The goal was to develop a model with sufficient detail to represent vertical and lateral heterogeneity at the well, multi-well, and field scale, which could be used as a tool for reservoir management including accurate prediction of original and remaining gas-in-place. This required that the model be finely layered (169 layers, 3-foot (1 m) average thickness) and have relatively small XY cell dimensions (660x660 ft, 200x200m: 64 cells per mi2). These criteria resulted in development of a 108-million cell model for the 10,000-mi2 (26,000 km2) area modeled. Although lithofacies geobodies tend to be laterally extensive, covering multi-section to township scales, small XY cell dimensions were required to allow the extraction of portions of the model for local reservoir simulation. Water saturations needed for original gas-in-place (OGIP) determination were estimated using capillary pressure methods and not measurements from wireline logs because accurate determination of water saturations using conventional wireline logs is complicated by deep mud filtrate invasion for typical drilling programs. Material balance methods for estimating OGIP are equally problematic because the reservoir is layered and differentially depleted and wellhead shut-in pressures (WHSIP) are strongly influenced by high-permeability interval properties and do not accurately represent all interval pressures; and pressure data for individual layers are sparse. The Hugoton geomodel may be the largest model of its kind (lithofacies-controlled, property-based water saturations).

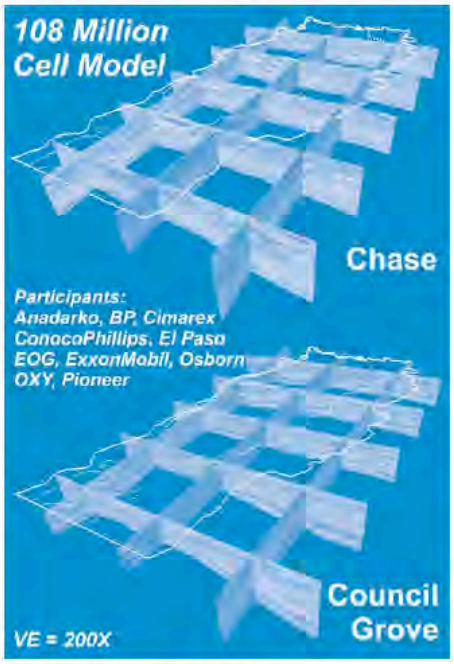
Core-based calibration of neural-net prediction of lithofacies using wireline-log signatures, coupled with geologically-constraining variables, provided lithofacies at wells. Stochastic methods were employed to estimate lithofacies between wells. Differences in petrophysical properties among lithofacies and within a lithofacies among different porosities illustrate the importance of integrated lithologic-petrophysical modeling and of the need for closely defining these properties and their relationships. An accurate lithofacies model, coupled with lithofacies-dependent petrophysical properties, allowed the construction of a 3-D geomodel that has been effective at the well, section (1mi2, 2.6 km2) and multi-section and field scales. Multi-well, multi-section simulations validate the property model and illustrate differential depletion relationship to layer property variability.

The model provides a detailed three-dimensional view of the 160-m reservoir comprised of thirteen shoaling-upward cycles vertically stacked in a low-relief shelf setting and is an analog for similar thin layered, stacked-cycle reservoir systems, including those in the Paradox and Permian basins and the Khuff Formation in Gwahar and North fields in the Arabian Gulf. Unprecedented 3-D views of shifting lithofacies patterns on a large stable shelf document sedimentary response to climate change during the transition from icehouse to greenhouse conditions in the Lower Permian. The model is a tool for predicting properties, water saturations and OGIP, is a quantitative basis for evaluating remaining gas--in-place, particularly in low-permeability intervals and has helped direct field management and field rules changes that could enhance ultimate recovery. The model and study also provides a "fast-forward" view of similar giant reservoir systems worldwide. Static model construction was completed in 2006. The consortium is now focused on the characterization of remaining gas-in-place and developing alternative drilling and completion practices for more efficient extraction of remaining reserves.

Key findings:

1. The Kansas-Oklahoma portion of the field has yielded 35-tcf gas (963-billion m3) over a 70-yr period from over 12,000 wells and an estimated 65% of the original gas-in-place in the central portion of the field.
2. Most remaining gas is in lower permeability pay zones of the differentially depleted, layered reservoir system.
3. The Chase (Hugoton) and Council Grove (Panoma) behave as a common reservoir.
4. Lithofacies bodies are laterally extensive and reservoir storage and flow units exhibit extensive lateral continuity.
5. The Hugoton reservoir free-water level (FWL) is sloped, ranging, west to east, from subsea depth of +1000 ft (+300 m) to +50 ft (+15 m).
6. Base on reservoir simulations, production is sustainable through 2050, provided the integrity of 40-70-yr old wells can be maintained.

For more information and references, see the full report online at the Kansas Geological Survey website www.kgs.ku.edu/PRS/publication/2007/OFR07_06/index.html).



Fence diagram from the 108-million cell, 80 x 120 mi, model for the Chase Group (Hugoton field, solid outline) and the directly underlying Council Grove Group (Panoma field, dashed outline), flattened at the top of each interval. Production is from thirteen upward-shallowing marine carbonate intervals (cooler colors) separated by continental siliciclastics (warmer colors).

The Next Generation of Oil and Gas Professionals: Futures in Energy 2007

Concerns have been raised over the past several years where the next crop of Oil and Gas Professionals will come from. PTTC is actively involved in answering the question with the Futures in Energy Program for high school teachers and students. With the help of 29 sponsors, PTTC's Rocky Mountain Region oil and gas industry outreach program continued successfully in 2007. A total of 15 high school students and 23 teachers were given an interactive training program focusing on oil and gas exploration technology—some at the Colorado School of Mines between June 18-22 and others in Pinedale, Wyoming between June 11-15. Participants were supplied with free room and board and instructional material. The courses for both the students and teachers included class room training, talks by local industry people on careers in the energy field, field visits to see actual oilfield operations and instruction at sites of geologic interest. After the course, nine students participated in a four week paid internship program with local energy companies in their community.

High school teachers received two semester hours of graduate-level re-licensing through the program and at the end of the training course were given a kit of instructional material so they could teach a six week module on oil and gas technology. This module addresses various aspects of petroleum exploration, integrating geography, mathematics and problem-solving skills with traditional geologic concepts. It is hoped that through the use of real data from the energy industry and federal agencies, including seismic profiles, electric logs, maps, and oil samples, that earth science and the study of natural resources will become relevant to students.

On the lighter side, everyone enjoyed the "Gushers and Dusters" simulation game in which players get to act out the risk and excitement enjoyed by members of the energy community. Overall, the program received great grades from all participants.

NOTE: High school students and teachers interested in joining next year's program, or companies interested in sponsoring through internships or money donations are encouraged to contact Mary Carr, mcarr@mines.edu, 303.273.3107.♦

Dr. Mary Carr, Director of PTTC Rockies, instructing at the Field Trip to Dinosaur Ridge

Animated Instruction on the Field Trip to the Duke Energy Natural Gas Processing Plant

Straightforward Approach for Reducing Electric Costs

By Naaman Gipson, EMS Electronics, LLC in cooperation with Bob Kiker, PTTC Texas Permian Basin

Electric power costs, which are often a major component of operating costs, do not necessarily require complex or expensive solutions to realize significant savings. This article focuses on one such solution that has application in several different oil- or gas-patch applications. Beyond just addressing reduced power consumption, the solution also provides transient surge protection and can reduce lost production due to equipment downtime, equipment replacement as well as repairs and associated labor hour reductions.

Although band-pass filters are not a new concept, Stems Electronics, LLC (STEMS), a four-year old company based out of Plainview, Texas, now offers a product that will provide line filter conditioning, enhanced power factor correction and top of the line surge and lightning protection, all in one device. Although a relatively new product, there are numerous U.S. applications serviced by a national sales organization. Products are also being sold in Canada, Mexico, Puerto Rico and Europe. Within the U.S., STEMS units are being applied by producers in different applications (artificial lift, injection pumps, compressors, etc.). Having realized positive results, several operators now purchase units on a regular basis.

Figure 1 illustrates why operators would do so. When applied in a 150-hp injection system in Wyoming, the units realized an 18% savings in daily electric cost. This system required eight STEMS units, costing approximately $28,000. With the demonstrated savings, considering purchased power only, this translates to a payout period of only 16 months. Long-term, there are other equipment/reliability savings that will be realized.

The unit is a highly sophisticated band-pass filter that blocks distortion in electrical power above and below normal signal range. It cleans up utility-supplied power to make power better fit the form of a 60-cycle sine wave, forcing current and voltage to form to the sine wave as well, which is the ideal design for AC motors. As a direct result, motors run smoother at lower temperatures, work more efficiently and require less power from the utility provider (KW). This creates an ideal operating environment for equipment, as well as increases power factor, reduces KVAR, amp draw and most importantly, KWH usage. If one compares the amount of electricity flowing to the site (KVA) with that performing work (KW), one sees a difference (KVAR). More current flows through the electrical system than is needed to do the required work. Excess current dissipates in the form of heat as reactive current (KVAR) flows through resistive components (motors, wires, switches and transformers).

Power Factor is the ratio between True Power (KW) and Apparent Power (KVA), known as Reactive Power (KVAR). Perfect unity of your power factor is 1.0, which means that there is no wasted energy. The voltage and current are in phase in the 60 cycle sine wave. Anything less than 1.0 (ex: 0.80, 0.65, 0.50) means there is energy being expended that is not being used. This often occurs in cyclic processes such as those using conveyers, compressors, grinders and pumping units where the motors are sized for the heaviest load. Losses caused by poor power factor are due to reactive current flowing in the system. These are watt-related charges and can be eliminated through power factor correction. When compared to the regular cost of power factor correction, load bank capacitors have a much longer payout than STEMS equipment. STEMS units are also very effective in reducing power factor penalties and demand charges. Keep this in mind! Whenever energy is expended, one pays for it whether it does useful work or is wasted as heat.

Before choosing a unit, one must first test the condition of the motor to determine which size unit is necessary to achieve satisfactory results. Going a step beyond that, STEMS doesn't "permanently" install units until initial performance demonstrates expected improvements. STEMS provides a three-year prorated warranty, a $2,000,000 product liability insurance policy (this means should a downstream protected motor be fried by lightning, the loss will be covered) and a 12-month money back guarantee that electrical consumption will be reduced by 5%. In actuality, savings average 10-12% with an average payout of 6-18 months (with all installations proving fewer than 24 months). Payouts are longer for smaller loads (less than 20 hp). STEMS offers a lease program to those who qualify and meet the criteria.

For further information, visit STEMS website (www.emselectronics.net) or contact Winfrey A. Shipp, President / Sales Manager (phone 806.292.7995, email washipp@nts-online.net).

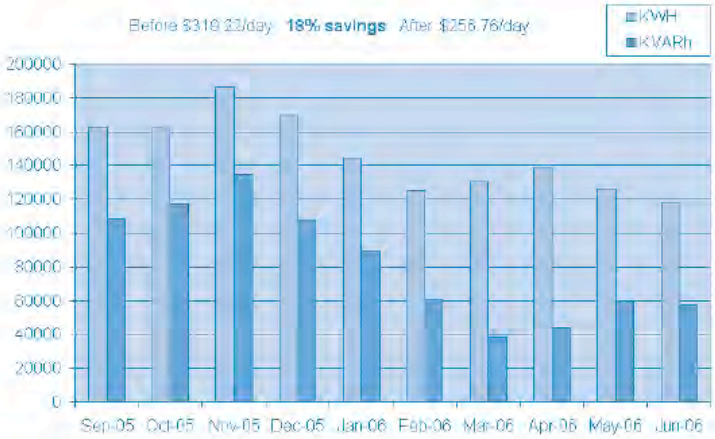


Figure 1. Power Cost Reduction in Wyoming 150hp, 5-Pump Injection System with STEMS Units

New Life for an Aging California Field

Warren Resources Inc. has embarked on an active redevelopment program in the Wilmington Townlot Unit (WTU) and adjacent North Wilmington Unit (NWU) in the central part of supergiant Wilmington field. These properties were originally unitized in 1973 by majors and, like most of California's mature fields, are now in the hands of an independent. Plans are to drill more than 500 wells in the next few years, targeting development in several reservoirs. Drilling will be done from cellars, which places wellheads and facilities below ground level. Estimates are that the WTU has produced only 20% of the estimated 727 million bbl of original oil-in-place, leaving an average remaining recovery potential of 228,000 bbl/well. Warren Resources estimates that WTU could yield another 92 million bbl of oil if the company were able to attain a 32% recovery factor.

Warren Resources took over operation of WTU in March 2005 and NWU at the end of 2005. The units produce oil mainly from the Upper Terminal formation at 4,000 ft and the shallower Ranger and Tar formations, all Tertiary in age. Since acquisition, the company has hiked WTU production from 375 bopd to more than 2,100 bopd. This increase results from additional production from new wells drilled and completed in the Upper Terminal, Ranger and Tar formations. The strategy at WTU is to develop seven-spot waterflood patterns in the Ranger and Upper Terminal formations. NWU now produces close to 400 bopd. Warren Resources has budgeted $68 million (74% in WTU) in 2007 for drilling and infrastructure development. This includes 34 producing and injection wells at WTU, and 14 new wells and 12 recompletions at NWU. The company plans to construct as many as five doublewide drilling cellars at WTU that can each accommodate two rows of wells in open cement-lined trenches. A skid-mounted drilling rig allows for rapid rig moves, and all fluid production and clean water reinjection occurs at wellheads in the cellars.

Tar formation horizontal wells: As of early May, the company had drilled eight Tar formation horizontals. The Tar formation was not previously exploited with secondary recovery. The first horizontal completion, which occurred in August 2006, had a 1,200 foot lateral and initially produced some 150 bopd. Modern logs from waterflood development drilling in the Upper Terminal formation is helping Warren Resources identify additional Tar formation wells. As of early May, the eight horizontal wells were averaging 100 bopd with a water:oil ratio (WOR) of 2, without any pressure maintenance. There are another 10 horizontal drilling locations already identified. Once the initial group of horizontals is developed, the company will evaluate the potential for additional horizontals, including in other potentially productive sands.

Upper Terminal formation: As of May 2007, the new Upper Terminal wells are averaging about 25 bopd. Some Upper Terminal wells drilled in the north area of the field have been below average production with very low WORs. Effects of water injection support, which is not evident yet, are expected within the next 12 to 24 months.

Ranger formation: Warren Resources drilled and completed its third Ranger formation well in the 1st quarter of 2007. Currently, the Ranger wells are producing an average of 40 BOPD with a WOR of 20. There are plans for an additional 5-10 Ranger wells in 2007.

Excerpted from "Central Wilmington Oil Field Due for Denser Development," Oil & Gas Journal, Feb. 19, 2007, pp. 36-37; and press releases (dated 10/2/06, 12/14/06, 5/4/07) by Warren Resources.

Graphic courtesy of Warren Resources (www.warrenresources.com)

Power From Stranded Gas Saving California Leases

A DOE-supported project (Oil Field Flare Gas Electricity Systems or OFFGASES) is demonstrating how distributed power generation from stranded natural gas reduces power costs and is making a difference in saving marginal leases. Results from four field demos with fuels of varying energy content/quality are demonstrating the possibilities.

- High-Btu gas (1,600 Btu/scf): boosted oil production in its three-well marginal oil field from 10 to 23 bopd.
- Medium-Btu gas (not meeting pipeline quality requirements): now producing 150 bopd in a 19-well field that had been at risk for abandonment.
- "Harsh" (contains naturally high levels of N_2, CO_2, H_2S) gas: brought into compliance with air emissions regulations by scrubbing hydrogen sulfide from the gas using a patented sulfur-treating system.
- Ultralow-Btu (as little as 15 Btu/scf): Just to flare it, producers have to spike it with purchased natural gas. Tests using FlexEnergy's Flex-Microturbine, which uses catalytic combustors, are ongoing. While the microturbine is working, improvements are still needed and testing continues.

View further information in DOE's Techline online at www.fe.doe.gov/news/techlines/2007/07061-Creating_Energy_from_Waste_Gas.html.

PTTC's low-cost regional workshops connect independent oil and gas producers with information about various upstream solutions. For information on the following events, that are sponsored or co-sponsored by PTTC, call the direct contact listed below or 1.888.THE.PTTC. Information also is available at ***www.pttc.org/national_calendar.htm****. Please note that topics, dates and locations listed are subject to change.*

September 2007

9/9-11 Midcontinent Region: *"Business" session @ AAPG Midcontinent meeting* - Wichita, KS. Contact: 785.864.7396

9/14-15 Rocky Mountain: *Structural Concepts and Applications in Rocky Mountain Hydrocarbon Plays* (Rocky Mountain Association of Geologists) - Denver, CO. Contact: 303.273.3194

9/TBD Appalachian: *Core and Sample Analysis and Interpretation* - Pittsburgh, PA. Contact: 304.293.2867 x 5443

October 2007

10/10 Central & Eastern Gulf Coast: *Technologies and Exploitation Strategies for Developing Naturally Fractured Reservoirs* - Shreveport, LA. Contact: 225.578.4538

10/18 Midwest: *Seizing Opportunities in a Mature Basin (Michigan O&G Association)* - Gaylord, MI. Contact: 269.387.8633

10/TBD Rocky Mountain: *Sequence Stratigraphy; Principles and Applications* - Golden, CO. Contact: 303.273.3194

10/TBD Texas: *Modern Methods Used To Capture Production Data and Implement Field Automation* - Midland, TX. Contact: 512.471.0320

November 2007

11/16 Rocky Mountain: *GeoGraphix Training, An Overview and Refresher Course* - Golden, CO. Contact: 303.273.3194

11/TBD Texas: *East Texas Field; Geology, Engineering, and Potential Future Exploration* - Kilgore, TX. Contact: 512.471.0320

11/TBD Texas: *Reservoir Engineering Symposium: Back To The Basics; Rocks, Oil and Gas* (Core Labs) - Houston, TX. Contact: 512.471.0320

December 2007

12/2 Central & Eastern Gulf Coast: *5th Annual Reservoir Symposium (Core Labs)* - Lafayette, LA. Contact: 225.578.4538

12/TBD Rocky Mountain: *GIS and GPS for Earth Scientist* - Denver, CO. Contact: 303.273.3194

12/TBD Texas: *Designing and Forecasting Waterflood Using "Reservoir Grail" - The Best Place to Find Oil is in the Oil Fields* - Dallas, TX. Contact: 512.471.0320

Check PTTC's online calendar frequently for changes. ***www.pttc.org/national_calendar.htm***

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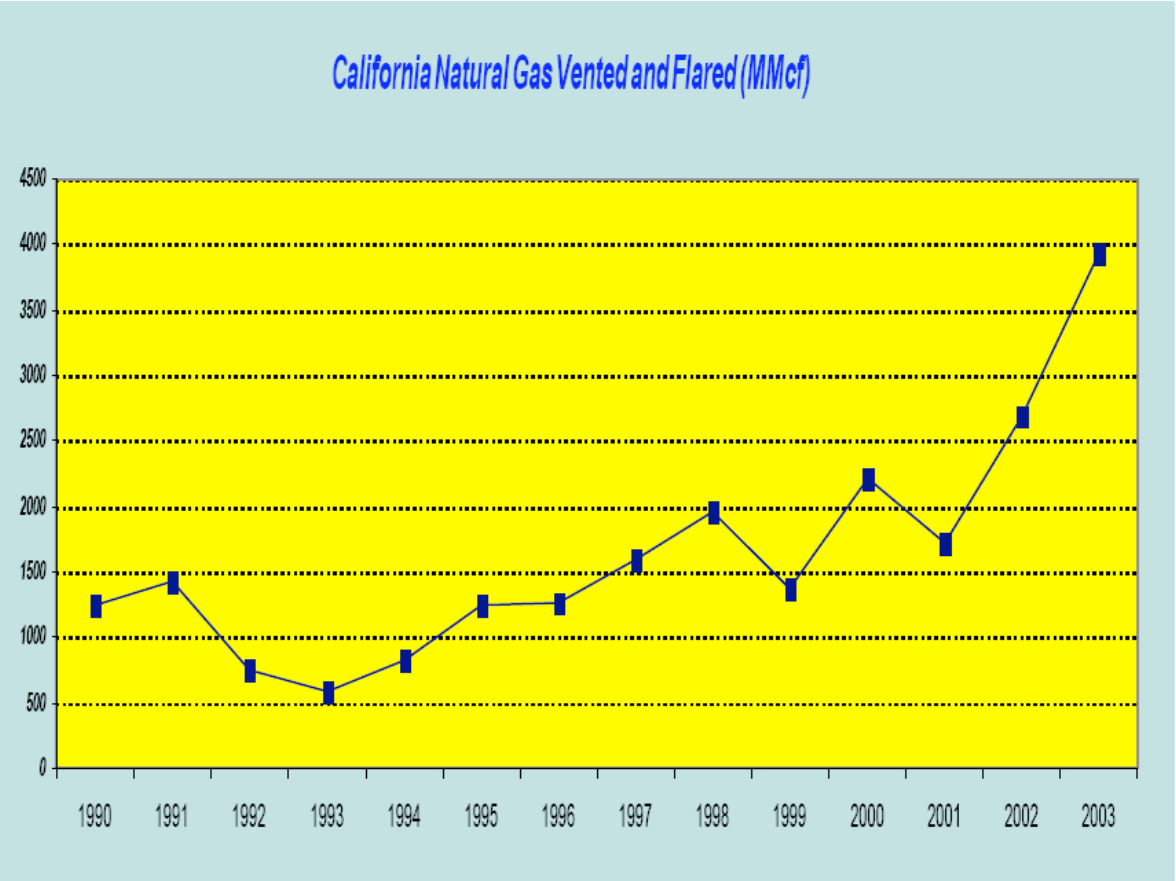
Overview of OFFGASES Project to Use Oil Field Stranded Gas to Generate Electrical Power

Bob Fickes

COPE

Why OFFGASES?

- Stranded gas has become a big problem for California Oil Producers
- CARB 80 rule change
- Increase in both gas prices and electricity prices
- Fewer options for gas disposal


California Natural Gas Vented and Flared (MMcf)
4500
4000
3500
3000
2500
2000
1500
1000
500
0
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003

Why OFFGASES?

- Stranded gas has become a big problem for California Oil Producers
- CARB 80 rule change
- Increase in both gas prices and electricity prices
- Fewer options for gas disposal

Why DG?

- Much more infrastructure for delivery of electricity than for gas
- Electricity costs one of the highest expenses in oil production

Why Turbines?

- **On the plus side**
  - Better air emissions, easier to permit
  - Less maintenance
- **On the minus side**
  - More equipment expense
  - Higher maintenance costs
  - Technically higher to maintain

St. James
Medium BTU Site

Gas Conditioning

Termo
High BTU Site

F350

BPCI
blackmer

Lessons Learned

What we thought would be major challenges

- Air quality and permitting
- Equipment maintenance & reliability
- Utility interconnection
- Power export

Air Quality & Permitting

- The three air agencies we have worked with all have been reasonable
  - Do your homework
  - Know the regulations

Equipment Maintenance

- Long term service agreements
- 2nd party non-factory service providers

Utility Interconnection

Depending on the Utility, the easiest part of the project or your worst nightmare

- LADWP signed agreement in 2 hours
- SCE 3-5 Months that ran Along With Construction No Delay In Startup
- PG&E 23 Months – Lots of Bloodshed

Power Export

Export Without Compensation

Contract for
Power Purchase Agreement
Currently in negotiations

Questions ?

Arnold Schwarzenegger
Governor

APPENDIX E
COMMENTS AND DISCUSSIONS WITH HOSTS

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Bob Fickes
California Oil Producers Electric Cooperative (COPE)

December 2008

December 2008
CEC-500-02-016

Prepared By:
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Interview with Chris Hall
General Manager of Drilling & Production's
Harsh gas site

- What was the biggest disappointment of the project?
    - Punitive rate structure. PG&E has levied stand by charges, departing load charges, reservation charges and a whole lot of other charges that make installing DG at my field an economic nightmare. If I go down for only 15 minutes once a billing period it triggers a whole lot of these charges and any savings that month are lost and in some cases my bill is larger than if I had not installed the DG
- In your view, what could be done to fix the problem?
    - I understand that there is a possibility of a tariff that would let me sell and wholesale market rates the surplus power that I generate. If I could sell the excess power or for that mater all the power produced then I would expect the project to be an economic success. I have an additional amount of gas going to boilers to make heat and to my flare that I could use to make electricity, 3 to 4 times what I am making now. If the production of electricity was a positive economic venture I would install extra generators to consume this stranded wasted gas. As a manager of a oilfield I have a responsibility to my royalty owners to run the field in the safest, environmentally prudent, and economically beneficial way. To be a prudent oil operator, I would need to install more DG if the economics justified it.
- What has been the reliability of the unit?
    - The turbine actually runs for long periods of time without any interruption. We have a total run time of about 92%. We have had several long stretches of run time, the longest being over 6 weeks. Change in our operation such as gas processing problems, changing out of the sulfa treat, can cause the DG to go down. The turbine can't run if we have a PG&E outage. This is a deliberate safety feature built into the unit. The big irony is that if PG&E has an outage for even a second, it trips off my turbine and then I go on to the draconian stand by rates. These PG&E caused trips happen frequently and every time they do the cash register at PG&E rings. I guess that they have a economic incentive to give me poor quality electricity. Add that to our limit on export where if we go over that limit it shuts down the unit I guess the fact that our run time is so high is quite an accomplishment for my operating staff.
- You mentioned not being allowed to export power to PG&E.
    - PG&E would like that I didn't export any power, and has not allowed me to export more than ½ the generators capacity. They really haven't given me a good reason for not accepting the excess power. They are not compensating me in any way for that power. I am sure that they sell that excess generation to another customer. We have a varying electrical load from turning on and off equipment during the day and if I find myself in a situation where I am exporting

too much then we are shut in and back on stand by rates. I have installed electric heaters to dissipate the excess power and keep our export under control. It seems rather foolish to run electrical heaters when it is 110 degrees out side but we do it to keep the turbine on.

- What is your experience with the Sulfa-Treat.
    - We have had a hard time getting the H_2S out of our gas economically. The system works exceptionally well and stripping the H2S out but we are not getting the run time out of the medium that we would like. We looked at several different types of mediums and are looking into trying some different types

- Mechanically how has the turbine worked.
    - We had our share of startup problems but once they were worked out the turbine had worked very reliably. There seems to be a problem that I would think is a design issue with IR, with the main bearings. We have a master service agreement with IR which is a very good idea when purchasing DG no mater what the brand. Service has bee very good and the response of the service folks is also very good.

Interview with Dick Russel
General Manager of St James Oil
Medium BTU gas site

- What was the biggest disappointment of the project?
    - The economics. I seem to get little if no value for the power I produce. LADWP has the deck stacked against us. We do get what they call their "Avoided Cost" for the power we sell in excess, however the nickel and dime us with a laundry list of charges that negates any savings. I am paying about the same each month to LADWP even though I produce enough electricity to run my field.
- If economics are a problem, why did you do the project?
    - We get our value from the project from allowing us to operate the field. We take the high Btu gas from our field and run it through the turbines. That allows us to sell the good gas, 115-120 mcf/day to So Cal Gas, and to produce the wells at 80+ barrels of oil a day. From that standpoint it has been a very successful project.
- What has been the reliability of the unit?
    - Actually fairly high. 90%+/- We have had our share of mechanical problems but when the units are running they are fairly trouble free. When they do have a problem however it is fairly expensive to fix.
- Have you had further complaints from the neighborhood over the noise problem?
    - Not since we installed the sound blankets. They cut the sound down well below the legal limit. We had to have a professional sound engineer do a survey and then we had a blanket designed to eliminate the specific frequency the turbines were emitting. I think that part of the sound problem was that the field had been idle and very quiet for several years before we installed the turbines. The turbine puts out a very high pitched noise, sort of like a jet engine, that is not very high on t he decibels scale, but is offensive and therefore needed to meet a much lower DB rating. Late at night when the ambient noise level was low you could pick out the turbine noise from the neighborhood. Now with the blankets it is hard to tell if they are running or not.
- Do you have any plans to expand the project on your own.
    - We came by 9 extra units when we acquired an oil property. They had been leased and we bought the units from the leasing agency. We are using some of them for spare parts and plan to install 2 maybe 3 of the units when we get the time and if LADWP assures us that it will be economic to do so.

Interview with Dennis Conley
Project Manager of DECOR Oil
Low BTU gas site

- Why did you decide to participate in this project?
    - DÉCOR specializes in operating hard and expensive to operate oil properties. Much of our production is offshore. We look for technological solutions to make a property easier and more profitable to operate. The Flex turbine had and still has the potential to greatly reduce our operating costs. At the Rincon site we are taking tale gas, waste gas, from an Ammine process that strips out the CO_2 from our produced gas. This waste stream is almost all CO_2 with a small amount of methane that brings the total heating value up to between 15 and 45 Btu/scf. We know of no conventional method to dispose of this waste stream without adding good sales gas that we would be able to otherwise send down the pipeline and sell. The Flex turbine, if developed, has the potential of eliminating this waste stream without the addition of sales gas and to make electricity. Potentially a win, win situation for DÉCOR.

- What was the biggest disappointment of the project?
    - We didn't get to fully test the unit because of lack of funds. We knew fully well that this was an R&D project and that there were risks. We enjoyed working with the OFFGAS team and were pleased with the progress. We did have some equipment component failures that set us back and we ran out of budgeted money before we were able to achieve the successes that we feel were inevitable.

- What did you learn from the project?
    - A gas feed stream of 15-45 Btu/scf is so low and so far below what is normally required to sustain combustion, usually above 350 Btu/scf, that we had our doubts that any machine could operate in these conditions. The Flex did however prove that it could continue to run in these very weak gas streams. This gave us a great deal of hope for this technology. We look forward to completing the project if additional funding can be found.

- Do you have any plans to install other DG at your property?
    - We are in construction with 2 IR 250kW machines at one of our offshore platforms. We are very interested in CHP. We have a lot of need for heat in our processes and the CHP aspect of making electricity along with the needed heat is very attractive to us. We have looked at replacing our thermal oxidizer that we currently take a lot of waste heat from with turbines, but the economics though close don't pencil out at this time.

Interview with Trent Rosenlieb
Production Manager of The TERMO Co.
High Btu gas site

- Why did you participate in the OFFGASES project?
    - We had 3 wells that had been idle for 3-4 years because we lost a pipeline easement that would deliver the gas to a site where it could be blended with on-spec gas and used. We felt with the rising oil prices these 3 wells were economic, and the electricity could help keep the operating cost down. We could also use the extra electric produced to help power a building that we had nearby.
- What was the biggest challenge with the project?
    - We thought going in that permitting through AQMD and the electrical interconnection permit with SCE would be big challenges, but those processes went fairly smoothly. We had some maintenance problems in the early part of the turbine operation. We also didn't get the volume of gas we had before we shut in the wells for 3 years. Turn down of the Capstone Microtrubines to match the new smaller gas volume was a problem that we solved when we found an independent service company that were ex-Capstone employees and were able to set up the turbines to run at the lower rate.
- How is the reliability of the equipment?
    - Once we got the turbines set for the lower gas volume they have run just fine for over a year. The turbines need to run continuously. Shut downs are very hard on the equipment and shorten the useful life of the equipment. We had much more trouble calls when we were running the equipment intermittently. We would shut in the turbines every night when we went home and turn them on in the morning. This was very hard on the equipment
- Was the project an economic success?
    - Yes. We are very pleased with the economics at our lease. We have worked over the wells and increased the oil production from 10-15 bbls/day to 35-40 bbls/day. At today's oil prices this is a very economic operation.
- Would you consider installing turbines where you have more stranded gas?
    - Absolutely. We feel that we now have the expertise to operate these turbines and make a profit with them. This is an environmentally sensible solution to stranded gas.

Arnold Schwarzenegger
Governor

ATTACHMENT I
CALIFORNIA GAS FLARED AND VENTED

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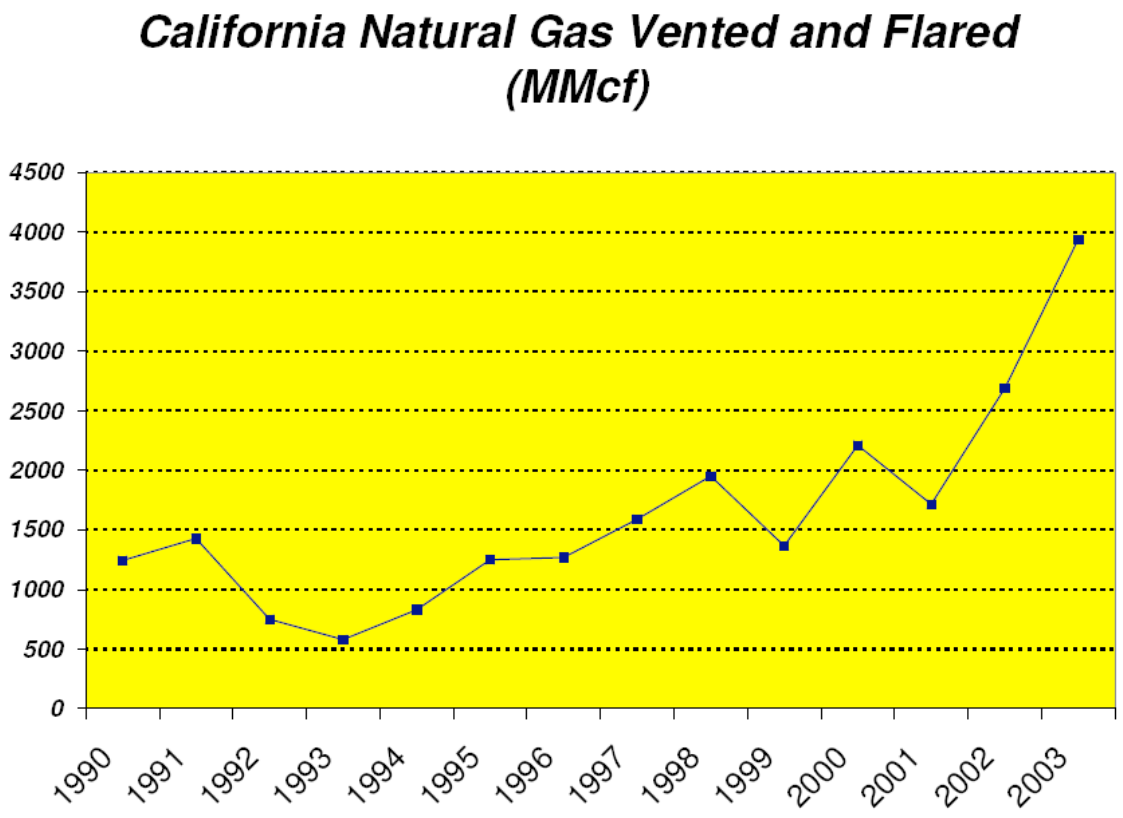
California Natural Gas Vented and Flared
(MMcf)
4500
4000
3500
3000
2500
2000
1500
1000
500
0
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003

Arnold Schwarzenegger
Governor

ATTACHMENT II
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PIER FINAL PROJECT REPORT

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Release Date: July 24, 2007

Oil and Natural Gas Program Uses Stranded Gas to Revive Oil Production

Project Generates Energy from Waste Gas to Restore Marginal Fields

WASHINGTON, DC — A U.S. Department of Energy (DOE) project is turning "stranded" natural gas at marginal, or low-production, oil fields into fuel for distributed electric power. The breakthrough is bringing previously idle oil fields back into production and could boost domestic oil production by some 28 million barrels per year within the next 10 years, helping to reduce the Nation's dependence on foreign oil sources.

Stranded gas is natural gas that is uneconomic to produce for one or more reasons: the energy, or Btu content, may be too low; the gas may be too impure to use; or, the volume may be too small to warrant a pipeline connection to the gas infrastructure. Non-commercial gas is sometimes produced along with oil, becoming an environmental liability. This unwanted byproduct of oil production has become a major problem in California oil fields where producers have been forced to abandon sites early, leaving valuable reserves of domestic oil untapped.

Typically, there are three ways to deal with stranded gas: venting or flaring the gas contributes to air pollution without any beneficial offsets from the gas; using electrical energy to re-inject the gas incurs significant extra costs; and, shutting down oil production leaves valuable oil in the ground.

Researchers have recently found another, useful, way to solve the stranded gas problem. A project managed by the Office of Fossil Energy's National Energy Technology Laboratory (NETL) called the Oil Field Flare Gas Electricity Systems, or OFFGASES, project, is turning this waste gas into a valuable fuel for distributed generation power units at marginal well sites in California.

Oil production sites are heavy electricity consumers. According to the California Oil Producers Electric Cooperative, electricity accounts for 40 to 60 percent of the operating cost of oil production and delivery, and it represents one of the highest expenses in producing marginal oil wells. In California, equipment such as pump jacks are all run by electricity, and this power must be purchased from the utility grid. This figures heavily in deciding which sites remain economical to produce as oil production declines and which ones must be abandoned. By using microturbines to harness the stranded gas and generate low-cost electricity - usually at 20 to 40 percent of the costs of utility grid electricity - the Distributed Generation/OFFGASES project is increasing oil production in previously hopeless fields, making use of a fuel that was previously considered unusable and uneconomic to produce. In electrical terms, the equivalent of about 45 megawatts of potential electrical generation has been identified as

stranded gas.

The project is conducting four field demonstrations with fuels of varying energy contents and quality. Three of the demonstrations have shown success so far:

A demonstration using high-Btu gas, which contains more than 1,600 Btu per standard cubic foot of gas, boosted oil production in its three-well marginal oil field from 10 barrels per day to 23 barrels per day.

A demonstration with medium-Btu gas, which does not meet the quality requirements for commercial pipelines in California, is now producing 150 barrels of oil per day in a 19-well field that had been at risk for abandonment.

A field containing "harsh" gas, which contains naturally high levels of nitrogen, carbon dioxide, and hydrogen sulfide, has been brought into compliance with air emissions regulations by scrubbing hydrogen sulfide from the gas using a patented sulfur-treating system.

The fourth demonstration deals with ultralow-Btu gas, which has as little as 15 Btu per standard cubic foot of gas. This gas is of such low quality that it's not immediately flammable and therefore cannot even be flared; operators have been spiking the weak gas with purchased commercial natural gas just to flare it. As part of the NETL-funded project, operators are now using FlexEnergy's Flex-Microturbine, a new technology that uses catalytic combustors and actually runs on 15 Btu gas. While the microturbine is working, improvements are still needed, and researchers are testing the equipment needed to turn this field into another success.

NETL demonstration partners include FlexEnergy, the Interstate Oil and Gas Compact Commission, California Oil Producers Electrical Cooperative, California Energy Commission, and California South Coast Air Quality Management District.

The project was awarded under DOE's Office of Fossil Energy's Preferred Upstream Management Practices program, which aims to slow the decline in America's oil production by pairing "best practices" and solutions from new technologies to an active campaign of disseminating information to domestic producers.

Contact: Mike Jacobs, FE Office of Communications, 202-586-0507

FED-Oil, natural gas program uses stranded gas to revive oil production

07/24/2007 by US DOE

(FED) A U.S. Department of Energy (DOE) project is turning "stranded" natural gas at marginal, or low-production, oil fields into fuel for distributed electric power.

The breakthrough is bringing previously idle oil fields back into production and could boost domestic oil production by some 28 million barrels per year within the next 10 years, helping to reduce the nation's dependence on foreign oil sources.

Stranded gas is natural gas that is uneconomic to produce for one or more reasons: the energy, or Btu content, may be too low; the gas may be too impure to use; or, the volume may be too small to warrant a pipeline connection to the gas infrastructure.

Non-commercial gas is sometimes produced along with oil, becoming an environmental liability. This unwanted byproduct of oil production has become a major problem in California oil fields where producers have been forced to abandon sites early, leaving valuable reserves of domestic oil untapped.

Typically, there are three ways to deal with stranded gas: venting or flaring the gas contributes to air pollution without any beneficial offsets from the gas; using electrical energy to re-inject the gas incurs significant extra costs; and, shutting down oil production leaves valuable oil in the ground.

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Oil production sites are heavy electricity consumers. According to the California Oil Producers Electric Cooperative, electricity accounts for 40 to 60 percent of the operating cost of oil production and delivery, and it represents one of the highest expenses in producing marginal oil wells. In California, equipment such as pump jacks are all run by electricity, and this power must be purchased from the utility grid.

This figures heavily in deciding which sites remain economical to produce as oil production declines and which ones must be abandoned.

By using microturbines to harness the stranded gas and generate low-cost electricity - usually at 20 to 40 percent of the costs of utility grid electricity - the Distributed Generation/OFFGASES project is increasing oil production in previously hopeless fields, making use of a fuel that was previously considered unusable and uneconomic to produce.

The project is conducting four field demonstrations with fuels of varying energy contents and quality. Three of the demonstrations have shown success so far:

A demonstration using high-Btu gas, which contains more than 1,600 Btu per standard cubic foot of gas, boosted oil production in its three-well marginal oil field from 10 barrels per day to 23 barrels per day.

A demonstration with medium-Btu gas, which does not meet the quality requirements for commercial pipelines in California, is now producing 150 barrels of oil per day in a 19-well field that had been at risk for abandonment.

A field containing "harsh" gas, which contains naturally high levels of nitrogen, carbon dioxide, and hydrogen sulfide, has been brought into compliance with air emissions regulations by scrubbing hydrogen sulfide from the gas using a patented sulfur-treating system.

The fourth demonstration deals with ultralow-Btu gas, which has as little as 15 Btu per standard cubic foot of gas. This gas is of such low quality that it's not immediately flammable and therefore cannot even be flared; operators have been spiking the weak gas with purchased commercial natural gas just to flare it.

As part of the NETL-funded project, operators are now using FlexEnergy's Flex-Mircoturbine, a new technology that uses catalytic combustors and actually runs on 15 Btu gas. While the mircoturbine is working, improvements are still needed, and researchers are testing the equipment needed to turn this field into another success.

NETL demonstration partners include FlexEnergy, the Interstate Oil and Gas Compact Commission, California Oil Producers Electrical Cooperative, California Energy Commission, and California South Coast Air Quality Management District.

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DOE Program Uses Stranded Gas to Revive Oil Production

July 31, 2007 // *Published as a news service by* IHS

A U.S. Department of Energy (DOE) project turned "stranded" natural gas at marginal, or low-production, oil fields into fuel for distributed electric power.

The equivalent of about 45 megawatts of potential electrical generation has been identified as stranded gas.

The breakthrough is bringing previously idle oil fields back into production and could boost domestic oil production by 28 million barrels per year within the next 10 years, helping to reduce the U.S.'s dependence on foreign oil sources, said the DOE.

Stranded gas is natural gas that is uneconomic to produce because:

- The energy, or British thermal unit (Btu) content, may be too low.
- The gas may be too impure to use.
- The volume may be too small to warrant a pipeline connection to the gas infrastructure.

Non-commercial gas is sometimes produced along with oil becoming an environmental liability. This unwanted byproduct of oil production has become a major problem in California oil fields where producers have been forced to abandon sites early, leaving valuable reserves of domestic oil untapped, said the DOE.

According to the DOE, there are three ways to deal with stranded gas:

- Venting or flaring the gas contributes to air pollution without any beneficial offsets from the gas.
- Using electrical energy to re-inject the gas incurs significant extra costs.
- Shutting down oil production leaves valuable oil in the ground.

Researchers have found another way to solve the stranded gas problem. A project managed by the DOE Office of Fossil Energy's National Energy Technology Laboratory (NETL) called the Oil Field Flare Gas Electricity Systems (OFFGASES) project turned this waste gas into valuable fuel for distributed generation power units at marginal well sites in California, said the DOE.

According to the California Oil Producers Electric Cooperative, electricity accounts for 40-to-60% of the operating cost of oil production and delivery and it represents one of the highest expenses in producing marginal oil wells.

In California, equipment such as pump jacks are all run by electricity and this power must be purchased from the utility grid. According to the DOE, this figures heavily in deciding which sites remain economical to produce as oil production declines and which ones must be abandoned.

By using microturbines to harness the stranded gas and generate low-cost electricity - usually at 20-to-40% of the costs of utility grid electricity - the OFFGASES project increased oil production in previously hopeless fields.

The project conducted four field demonstrations - three have shown success - with fuels of varying energy contents and quality, said the DOE. The successes included:

- A demonstration using high-Btu gas, containing more than 1,600 Btu per standard cubic foot of gas, boosted oil production in its three-well marginal oil field from 10 barrels per day to 23 barrels per day.

- A demonstration with medium-Btu gas, which does not meet the quality requirements for commercial pipelines in California, produced 150 barrels of oil per day in a 19-well field that had been at risk for abandonment.
- A field containing "harsh" gas, which contains naturally high levels of nitrogen, carbon dioxide and hydrogen sulfide, was brought into compliance with air emissions regulations by scrubbing hydrogen sulfide from the gas using a patented sulfur-treating system.

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Source: U.S. Department of Energy (DOE) Office of Fossil Energy.

Cogeneration & On-Site Power Production

Methane from oil and gas operations - a source of free fuel for on-site generation?

*Methane is a powerful greenhouse gas, but also a potential source of 'free' fuel. Previous articles in this series have looked at methane emanating from landfill sites and coal mines. Here, **Mark Schlagenhauf, Suzie Waltzer, Rhonda Lindsey Jacobs** and **Christopher J. Freitas** survey the scope for making on-site use of methane from oil and gas operations.*

Oil and natural gas are found stored in porous and highly permeable reservoir rock, trapped under low permeability cap rock. Within the reservoir, oil and gas are arrayed vertically according to their densities, oil at the greatest depths and natural gas above. Natural gas is also usually found dissolved in the oil. The natural gas held in rock reservoirs typically contains between 70% and 100% methane. Methane in both oil and gas is produced during the thermal degradation of organic matter in sedimentary rocks. Natural gas may escape from the oil and gas system at several points, including oil wells, oil refineries, natural gas wellheads, gas processing plants, gas transmission and distribution pipelines, and gas storage facilities.

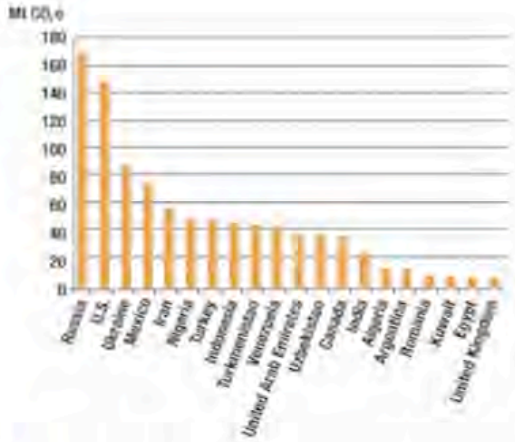
Proven, cost-effective technologies and practices exist for recovering methane that have broad applicability globally and across the industry. Oil and gas companies, both in the US and internationally, have successfully implemented projects to reduce methane losses cost-effectively from the production, processing, transmission, and distribution of oil and natural gas. However, even with the industry's application of these technologies and practices, global emissions estimates show that there are still significant profitable opportunities for the oil and gas industry throughout the world. This article focuses on cost-effective opportunities to reduce methane emissions that would otherwise be vented or flared, and to use recovered methane for on-site fuel and power generation.

Global methane emissions and flaring

Oil and natural gas operations are a significant source of global methane emissions, constituting approximately 17% of total man-made sources. In 2005, global oil and gas methane emissions totalled approximately 82 billion cubic metres (Bcm), equivalent to about 1165 million tonnes carbon dioxide equivalent ($MtCO_2e$). Based on an average natural gas price of US $7 per thousand cubic feet (Mcf), this equates to a loss of about $20 billion in revenue. In addition, these emissions have an equivalent annual greenhouse gas effect of adding more than 200 million vehicles to the roads.

These results indicate a significant economic and environmental opportunity for oil and natural gas companies to recover and use methane as clean energy source. Furthermore, the US Environmental Protection Agency forecasts that methane emissions will grow globally by more than 33% during 2005-15.

Figure 1 shows global oil and gas methane emissions estimates for the top 20 emitting countries. As shown in Figure 1, the leading emitters of methane from oil and gas operations include Russia, US, Ukraine and Mexico, all of which are M2M partner countries (see box, page 93).



Click here to enlarge image

In addition to the methane losses from venting or leakage, the results of a recent global survey by the US National Oceanic and Atmospheric Administration using satellite data – funded by the World Bank's Global Gas Flaring Reduction partnership – showed that oil-producing companies and countries burned close to 170 Bcm of natural gas in 2006. According to this study, 170 Bcm of natural gas equates to 27% of total US natural gas consumption and 5.5% of total global production of natural gas for the year. In addition, the study found that if the gas had been sold in the United States instead of being flared, the total US market value would have been about $40 billion. To access the report, visit http://www.ngdc.noaa.gov/dmsp/interest/gas_flares.html

Major methane sources from oil and natural gas

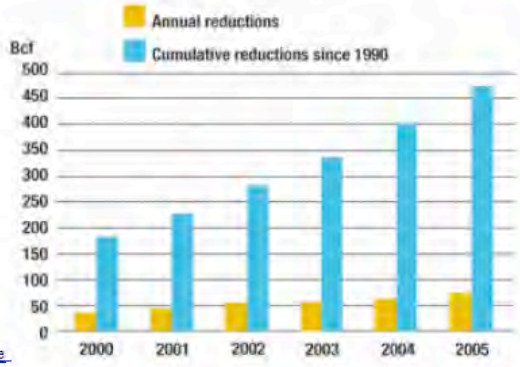
Methane emissions occur in all sectors of the natural gas industry, from drilling and production, through processing and transmission, to distribution as well as end-use as fuel. Methane emissions from the natural gas sector primarily result from normal operations, routine maintenance and system upsets. As gas moves through the system, emissions occur through intentional vents and unintentional leaks. Venting can occur from typical equipment design or operational practices, such as the continuous bleed of gas from pneumatic devices (that control gas flows, levels, temperatures and pressures in the equipment), as well as venting from well completions during natural gas production.

Another example is methane emissions that result from the 'blowdown' or venting of high-pressure gas left within a compressor when taken offline to control demand or for maintenance. Methane losses can also occur from leaks (or fugitive emissions) in all parts of the infrastructure, from connections between pipes and vessels as well as valves and equipment. Leaks can also occur from the seals in pumps, compressors, valves and instruments.

Oil industry methane emissions result primarily from field production operations, such as venting gas from oil wells, oil storage tanks and production-related equipment. Venting and flaring of methane and heavier gaseous hydrocarbons (also known as 'associated gas') often occur during oil production. This gas is often wasted as markets for gas at remote oil production sites might not exist. This is especially common in places such as Russia, and offers a large opportunity for such projects as electric power generation.

Opportunities to recover and use methane

The success of US and international oil and gas companies suggest that there are significant opportunities globally to reduce methane emissions cost-effectively. For example, Figure 2 shows that since 1990, US Natural Gas STAR partner companies have reported 13 Bcm (459 Bcf) in methane emission reductions through the implementation of over 80 cost-effective technologies and practices.1 In 2005 alone, Natural Gas STAR partners reduced methane emissions by approximately 2.1 Bcm (74.2 Bcf), which is equivalent to additional revenue of more than $560 million in natural gas sales (based on a 2005 average gas price of $7.51/Mcf). Moreover, the 2005 emission reductions have a global warming equivalent of the carbon sequestered by approximately 8.2 million acres of forest in one year. In addition, as outlined in Gillis et al (2007), methane emission reduction projects are being implemented successfully at global oil and gas operations to address major emission sources.2



Click here to enlarge image

Methane emission reduction strategies generally fall into one of three categories:

- reducing venting or fugitive emissions through technologies or equipment upgrades
- improvements in management practices and operational procedures
- enhanced management practices that take advantage of improved technology.

Various project options such as compressor upgrades, vapour recovery from oil storage tanks, pneumatic device replacements and leak surveys have broad applicability globally and across the industry.

Companies can recover their investments through a number of economic channels, including gas sales revenue, on-site fuel use, reduced labour costs, reduced capital replacement costs, lower environmental permitting costs and carbon credit revenue. While in the US the gas market is well-developed, internationally, especially in developing countries, this is often not the case. Lack of gas markets represents a problem that often leads to wasting the valuable energy source of the associated gas and vented methane. This represents a unique opportunity for combined heat and power (CHP) developers. While the oil companies may use some of the gas to fuel their own operations, often the oil companies do not have expertise or interest in the power or CHP sector. But often oil companies are willing to work with developers that have an interest in this area.

Click here to enlarge image

Government policies, however, may need to be modified to provide sufficient economic incentives so that the gas can be successfully captured and utilized for electricity generation or CHP. And laws may have to be changed to allow independent power producers and distributed generation to enter the market. USAID specializes in supporting development of economic energy markets and has a number of programs. Additional information is available at

www.usaid.gov/our_work/economic_growth_and_trade/energy/, and at the websites of development partners, such as www.naruc.org, www.usea.org, and www.gvepinternational.org.

Microturbine technology for electricity generation

As noted above, natural gas is often produced in association with oil production. In the United States, the associated gas is sometimes flared where permitted, but creates air emission challenges in many places and is therefore vented. The inability to flare the amounts of gas produced has caused oil production to be shut-in for lack of compliance with regulations. This means that the valves are closed so there is no oil or gas production from the well. By adding a turbine, emissions are lowered and the valve can be reopened and production is restarted.

A research pilot demonstration project funded by the US Department of Energy's National Energy Technology Laboratory, is turning methane gas into a valuable energy source through the use of distributed generation power units at marginal well sites in California. Electricity production is one of the largest costs associated with oil production. In California, equipment such as pump jacks are all run by electricity and this power must be purchased from the utility grid. Partners including independent oil producers, the Interstate Oil and Gas Compact Commission, and the California Oil Producers Electric Cooperative (COPE) successfully demonstrated the use of microturbine technology for electricity generation on site.

By harnessing the energy in the waste gasses, the pilot projects brought shut-in fields to full production, eliminated the need to flare the gas, and reduced costs associated with oil production. Details of the project can be viewed at http://www.netl.doe.gov/technologies/oil-gas/Petroleum/projects/EP/ImprovedRec/15444IOGCC.htm.

In conclusion, the oil and gas sector represents an excellent opportunity for both near-term reduction of methane emissions and cogeneration and on-site power applications. US government agencies are actively pursuing methane partnerships with companies interested in commercially viable operations in 20 countries.

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1 Natural Gas STAR Recommended Technologies and practices, http://www.epa.gov/gasstar/techprac.htm

2 Gillis, Brian, Waltzer, Suzie, Heath, Milton, Cormack, Jim, Ravishankar, Krish; Technology drives methane emissions down, profits up (OGJ, August 13, 2007, page 20).

Methane to Markets Partnership

The Methane to Markets Partnership (M2M) is an international initiative comprising 20 countries and the European Commission, focused on advancing the cost-effective, near-term recovery and use of methane as a clean energy source. The role of the Partnership is to bring diverse organizations from the private sector, the research community, development banks, and other organizations together with international governments to stimulate development of methane-saving projects. Under this framework, US EPA launched Natural Gas STAR International, a global partnership with oil and gas companies. Natural Gas STAR International builds on the success of the domestic Gas STAR Program, to promote cost-effective methane emission reduction activities in the international oil and gas sector. To date, there are over 110 US Partners in the Natural Gas STAR Program representing 56% of the natural gas industry in the US, including 19 of the top 20 production companies. As of 2006, eight companies joined Natural Gas STAR International to advance the global recovery and use of methane as a valuable clean energy source.

The Methane to Markets Project Expo held in Beijing, China, 30 October–1 November 2007, brought together oil and gas operators and other stakeholders to combine resources and knowledge for profitably harnessing methane emissions. For further information visit www.methanetomarkets.org.

For further information on Natural Gas STAR or the technologies discussed in this article, www.epa.gov/gasstar.

Case study: Santa Barbara oil facility

The DCOR oil facility near Santa Barbara has installed microturbines to deal with its natural gas emissions. The only technology suitable for the 42 Btu gas at the site was FlexEnergy's Flex-Microturbine. This innovative technology can run on a range of fuels from as low as 15 Btus per cubic foot (1.5% the strength of natural gas) to as high as 3000 Btus per cubic foot (three times as strong as natural gas). Its emissions are well below those from any other power plant, and meet the toughest requirements of even the California Air Resources Board. The Flex-Microturbine's fuel range and clean emissions could make it the standard solution for a large fraction of stranded gas in the future.

Click here to enlarge image

The Flex-Microturbine is the first system to mix fuel and air at atmosphere and use catalytic combustion to oxidize the weak mixture. This is what gives it the fuel flexibility and ultra-low emissions. The Flex is still completing development, but has already proven to be robust, and has logged over 5000 hours of operation, including over 3000 hours on a single prototype. FlexEnergy is in the process of obtaining R&D and commercialization funds to complete the development, but a line of potential clients is already forming.

The Flex-Microturbine was originally developed for biomass applications (landfill gas, digester gas, wood gasifier gas) with grants from the DOE's renewable energy division; and its extension to help resolve oilfield problems is a fortuitous benefit. The Flex can run off several streams of methane gas from landfills, coal mine vents, shut-in gas wells, and so on, making it highly valuable as a greenhouse gas abatement technology, because methane has a global warming potential 23 times that of carbon dioxide. This waste-to-energy technology cross-over from renewables to fossil and back to renewables is the kind of clean, flexible, greenhouse gas reduction technology DOE hopes to foster in future.

Cogeneration and On-Site Power Production November, 2007
Author(s) : Suzie Waltzer Mark Schlagenhauf Rhonda Lindsey Jacobs Christopher Freitas

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Using stranded gas to revive production

Energy generated from waste gas restores marginal fields.

By Judy Maksoud, Senior Editor

A US Department of Energy (DOE) project is turning stranded natural gas at marginal or low-production oil fields into fuel for distributed electric power.

This breakthrough in using stranded gas is bringing previously idle oil fields back into production and could boost domestic oil production by 28 million bbl per year within 10 years of its inception, according to the DOE.

Typically, associated gas is vented or flared, re-injected, or left in the ground. A project called

A 30 kW flex microturbine is now generating electricity on a California oilfield by burning ultra-low-BTU gas.

Oil Field Flare Gas Electricity Systems (Offgases), which is managed by the Office of Fossil Energy's National Energy Technology Laboratory (NETL), has recently introduced another way to deal with stranded gas. This new solution is turning waste gas into fuel for distributed generation power units at marginal well sites in California.

Mature oil production sites are often heavy electricity consumers. According to the California Oil Producers Electric Cooperative, electricity accounts for 40% to 60% of the operating cost of oil production and delivery, and it represents one of the highest expenses in producing marginal oil wells. Pump jacks and other oilfield equipment are run by electricity, and in California, power to operate the equipment is purchased from the utility grid. As a result, the cost of energy figures heavily in the decision to produce or abandon a declining field.

By using microturbines to harness the stranded gas and generate low-cost electricity — which according to the DOE is usually 20% to 40% of the cost of utility grid electricity — the Offgases project is increasing oil production in fields that were previously cost prohibitive to produce. In electrical terms, the equivalent of about 45 MW of potential electrical generation has been identified as stranded gas.

The Offgases project demonstrates how associated gas of various heat content values and quality can be used to generate electricity. This research has been applied in four field installations: one using a high-British thermal unit (Btu) stranded gas with a value above 1,600 Btus per standard cubic foot (scf) of gas; one using a medium-Btu gas that does not meet the quality requirements for commercial pipelines in California; one using harshly

contaminated fuel gas with high levels of nitrogen, carbon dioxide, and hydrogen sulfide; and one using ultra-low-Btu gas (below 300 Btu/scf).

The high-Btu gas project involves stranded gas containing more than 1,600 Btu/scf. The oilfield had been shut in for eight years because the operator had no means of handling the natural gas associated with the oil being produced from the field. Researchers chose a Capstone 30-kW microturbine for the project, coupled with a horizontal scrubber to remove produced water, and a small compressor to achieve the line pressure needed for the turbine. After the wells were reworked, production increased to 23 b/d. Production was estimated at about 9,000 scf/d of 1,650-Btu/scf gas.

As of June 2007, researchers were monitoring the project and collecting runtime and equipment reliability data as well as air emissions and operating maintenance figures.
A second application of the new technology took place in a well producing medium-Btu gas that did not meet the quality requirements for commercial pipelines in California. Three Capstone 30-kW microturbines were installed on site to generate power, and a large compressor was added to achieve the pressure needed for the microturbines. The solution also included a vertical scrubber to remove associated liquids and a small refrigeration dryer. The 19-well field that had been at risk for abandonment is now producing 150 b/d of oil, according to a report by the DOE.

The third field in the demonstration contained "harsh" gas — gas that contains naturally high levels of nitrogen, carbon dioxide and hydrogen sulfide (H2S). The unusable gas was being flared, but as of Sept. 6, 2006, enough H2S is being scrubbed from the gas to bring air emissions into compliance using a patented sulfur treating system.

Now, an IR 70-kW microturbine generates electricity through an interconnect permit with Pacific Gas & Electric. The system produces two segregated streams of gas, one containing about 6,000 parts per million H2S and the other containing no H2S. The separate streams allow researchers to test various concentrations of H2S. As of late 2007, researchers were in the maintenance and monitoring phase of the project, collecting runtime and equipment reliability data along with operating maintenance figures.

The fourth demonstration in the Offgases project addressed ultra-low-Btu gas, in this case, defined as gas containing as little as 15 Btu/scf. Because gas of this low quality is not flammable, the operators had been spiking the weak gas with purchased commercial natural gas so the gas could be flared.

As part of the NETL-funded project, operators on this field are now using a 30-kW Flex microturbine to generate electricity. This microturbine employs a new technology that uses catalytic combustors and runs on 15-Btu gas. While the microturbine is working, improvements are still needed to turn this field into a success, the DOE said.

Reservations aside, the present situation that has eliminated flaring along with the cost of adding commercial gas to make flaring possible is an obvious step in the right direction.

Office of Fossil Energy

eye on environment

Photo credit: Terry Ackman, NETL

Advanced Technology Issue

Summer 2004, Vol. 9, No. 1

This Edition of Eye on Environment Highlights Environmental Benefits of the Exploration and Production Program

Technological Advances

Exploration 2
Drilling 4
Production 5
Operations 8
Conclusions 9

NETL's Advanced E&P Technology Research Promotes Environmental Protection

Exploration and production trends in recent years have stressed, "*Smarter, Farther, Deeper, Cleaner*" and the newest trend is "*Smaller*". NETL's research has helped to develop more efficient E&P technologies that allow industry to drill fewer holes and still produce more oil and gas. Today the industry is able to add 2 to 4 times more oil and gas to the nation's reserve base per new well than in the 1980's. These improved technologies result in fewer waste products from each well; fewer and smaller wells result in less surface disturbance.

Smarter	Intelligent computing, "smart wells"
Farther	Horizontal wells, multiple laterals
Deeper	Deep offshore, subsalt exploration
Cleaner	Improved refineries, Gas-to-liquids conversion, downhole separator
Smaller	Footprint, reduced environmental impact, microhole technology

Technological Advances

Technology advances are making exploration, development, production, processing and distribution of oil and natural gas cheaper, more efficient, and more protective of the environment. Advances come under the headings of: 1) exploration, 2) drilling, completion and stimulation, 3) production, 4) operations. DOE funded projects have developed, tested, adapted and implemented field demonstrations of many of the technological advances introduced to the petroleum in the past 20 years.

Major contributions to future domestic supplies must come from new frontiers in such geologically challenging and operationally complex settings as the Alaskan North Slope, deep formations, deepwater offshore, and lower permeability formations in the Rocky Mountain States. Today's producers are applying a host of new technologies and strategies to minimize the environmental impact of oil and natural gas operations in these frontier regions. DOE sponsored projects are providing solutions to meet the challenges of working in sensitive environments, such as the tundra, arid plains (**Figure 1**), and coastal areas by developing and demonstrating new advanced technologies.

DOE's Oil E&P program has focused on developing technologies to find new reserves, improve drilling efficiency, reduce costs, increase production through enhanced recovery methods, and prevent mature domestic fields from abandonment. These improved technologies and strategies have environmental benefits.

BENEFITS:

Innovative E&P technologies and strategies have had positive environmental benefits in reduced impact on lands, surface waters and aquifers, wildlife, and air quality. The overall push to improve E&P has led to more efficient methods; which increase the use of remote sensing exploration, reduce the size of well pads, limit excess roads and surface facilities, decrease the volume of produced water and reinject much of it, reduce the number of wells drilled (fewer dry holes, more multilateral wells), and actively promote environmental considerations in exploration and production practices.

Photo credit: Lee Gerhard

Figure 1 *To improve the public's perception of the petroleum industry, efforts are made to reduce the visual impact by painting oilfield equipment to blend into the environment.*

EXPLORATION

Exploration for oil and gas has advanced tremendously is the past two decades. Seismic technology has evolved from simple 2-D surveys to complex 3-D and 4-D surveys capable of locating reservoirs at great depths, under salt or other structures and mapping migration of fluid saturations. Satellite imagery and aeromagnetic surveys have added to the ability to analyze potential reserves and monitor fluids with little or no surface impact. Intelligent computing software has significantly improved exploration methods.

BENEFITS:

The environmental benefit of reduced drilling footprint is illustrated in several exploration projects. Technologies which allow the operator to reduce the number of wells they drill to optimize production results in fewer acres of land disturbed. Targeted horizontal wells (to produce the same volume of oil as multiple conventional vertical drilling) can reduce the number of wells in or around sensitive areas, or can penetrate under these areas without disturbing the surface. In arid climates such as the Williston Basin a single horizontal well may cut the number of wells and their associated roads by factors of three to ten. Fewer roads also mean less impact on native animal species and their breeding and migration areas.

Luff Exploration of Denver, CO continued research in the Red River formation of the Williston Basin in North and South Dakota and Montana has led to the development of an Intelligent Computing System (ICS). ICS has been developed as a tool to assist decision makers in selection of optimal drill-site locations, to reduce risks associated with drilling operations and to reduce the number of dry holes drilled. ICS uses clustering, artificial neural networks, and classical regression methods to combine existing seismic, geologic and engineering data for predictions of reservoir potential. Based on ICS analysis, Luff converted 16 vertical wells to horizontals resulting in a 10-fold increase in production with no new wells being drilled. This simultaneously reduced the drilling footprint, and increased reserves and recovery in the Williston Basin. The software is not specific to any region and can easily be applied to other mature fields and basins in the US to improve economics and reduce environmental impact.

Advanced Resources International has identified new resources on the Fort Berthold Indian Reservation by using advanced seismic technologies to identify trapped oil in formations under Lake Sakakawea (**Figure 2**). The Three Affiliated Tribes-Mandan, Arikara and Hidatsa–have 150,000 acres of tribal lands that lie beneath Lake Sakakawea, a reservoir created when the Missouri River was dammed in 1951. The DOE program provided the funds to purchase 200 miles of seismic, Landsat and aero-magnetic data covering the area around and beneath the lake. Ten structural leads that are accessible by horizontal wellbores have been identified beneath the narrow, sinuous lake. Horizontal wells will allow the tribe to access this rich new resource with minimal impact to the fragile arid lands surrounding the lake.

BENEFITS:

The cost of a dry hole is easy to see in economic terms, in environmental terms it may be less obvious. Essentially each dry hole results in another well being drilled to attempt to establish production. Exploration and between well monitoring technologies can result in fewer dry holes, and thus reduced environmental impact.

Figure 2. *New exploration and drilling strategies allow exploration and development under Lake Sakakawea, while preserving and arid high plains environment.*

Crosswell electromagnetic logging tools developed by ElectroMagnetic Instruments and Lawrence Livermore National Laboratory are leading to more efficient exploration, well monitoring and reducing the number of dry holes. Crosswell electromagnetic imaging tools provide the resolution to accurately map fluid properties in the areas between wells that has been missing from conventional seismic analysis. Crosswell imaging has been successfully tested in waterfloods and steamfloods in California, and to monitor CO_2 floods in New Mexico. The tools (**Figure 3**) are moved up and down in neighboring wellbores, and have the ability to image uncased wells, and through fiberglass and steel well casings. The latest development is a design which will allow the tool to image the area surrounding the wellbore through a single well, which will significantly reduce logging costs, and is particularly important for deep offshore wells. Thru-casing, single-well imaging can result in fewer wells to explore and plan offshore development. Crosswell imaging can significantly reduce the number of exploratory wells, and reduce surface impact during oil field production due to improved monitoring of water, steam and CO_2 injection.

Figure 3. *Crosswell transmitters and receivers can reduce the number of wells for exploration and monitoring water, steam and CO_2 flood operations.*

BENEFITS:

Technologies that improve monitoring in deepwater offshore wells have the additional advantage that can reduce unnecessary drilling and testing procedures. Crosswell imaging and Subsalt imaging both reduce the number of exploratory wells necessary to model the reservoir and assist in prediction of the best location of development well.

Sandia National Laboratory is conducting research designed to enhance the understanding of the forces subsurface salt bodies exert on oil and gas wells, and provide technologies to counter the effects of salt deformation in the deepwater Gulf of Mexico. Salt deformation may result in severe damage to wellbore and equipment through lateral motion resulting in shear and twisting action, and may cause hydrocarbon leaks into the ocean. Research conducted by Sandia is designed to enhance the understanding of the stress fields associated with salt diapers and the forces that subsurface salt bodies exert on oil and gas wells, and provide technologies to counter the effects of salt deformation. The research shows how to more accurately plan subsalt wells that penetrate massive salt diapirs, and how to design robust well casings to resist salt movement. The 3-D visualization

software and casing design tested at Mad Dog field and Thunder Horse North field (**Figure 4**) operated by BP America with multiple partners reduced costs by $30 million dollars, and potential hydrocarbon leakage into the waters of the Gulf of Mexico was avoided. The project focus on identifying, quantifying, and mitigating potential well integrity issues associated with subsalt and near-salt deepwater Gulf of Mexico reservoirs.

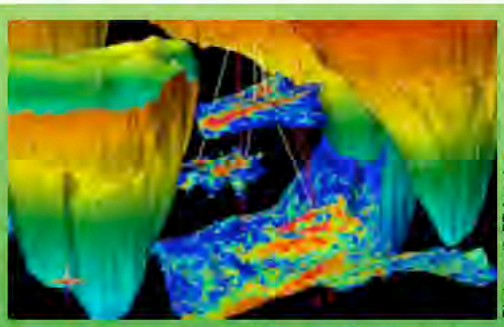

Photo credit: BP America

Figure 4. *Computer model showing the effects of salt diapers (tooth shaped) adjacent to stacked reservoir sands are used to target safer drilling locations.*

BENEFITS:

Computer models and more robust well casings can prevent pollution of the ocean by drilling fluids and hydrocarbons resulting from damage to wellbores caused by salt deformation. Identification of safer well locations and new designs to strengthen the well casing will prevent casing leaks, which could damage the marine ecosystem.

DRILLING

Innovations in drilling technology have significantly reduced the environmental impact in recent years. DOE projects have been in the forefront of sponsoring technologies which use smaller drilling pads, directional drilling, smart wells, slimhole/microholes, coiled tubing, and measurement while drilling technologies. Exploration technologies assist drilling operations to be more effective by providing better targets for the new drilling procedures. The innovative exploration and drilling technologies applied together can produce more oil and gas from fewer wells. Fewer wells means less land disturbed by drilling operations and the associated surface infrastructure and transportation systems. Microhole drilling and completion technologies are the focus of a major effort in 2004-2005 in DOE's E&P oil program.

BENEFITS:

Microhole drilling opens up a domestic resource of 218 billion barrels of oil found at depths of less than 5,000 ft. In the future microhole drilling will be conducted using helicopter transport to field sites, which will further reduce the footprint and reduce environmental disturbance. The small rig size also contributes to the reduced visual impact of drilling that has caused public objections in some areas. Helicopter transport of equipment, materials and personnel to sensitive areas will benefit the wildlife and ecosystems by eliminating contact. This is particularly important to migrating species and species which require specific areas for calving grounds or nesting.

Los Alamos National Laboratory and the Rocky Mountain Oilfield Testing Center (RMOTC) are working together to develop a microwell program for drilling and completing wells with diameters of less than 3 inches. The RMOTC site near Casper, Wyoming has over 10,000 acres of federally managed lands and hundreds of existing wells with seismic and reservoir data providing an excellent area to test new drilling and completion technologies. Los Alamos has designed advanced sensors for use in microborehole using miniaturized hardware and coiled tubing, and a small microhole drilling apparatus (**Figure 5**) which can be transported on a small truck. The drilling equipment is small, easily transportable and the supplies needed to complete wells are likewise reduced. The overall impact of microholes is to reduce the drilling footprint. The small drilling pads and minimal facilities required for exploratory drilling and production are specially designed for sensitive environments like the arid Rocky Mountain States.

Northwest Alaska Native Association (NANA) representing 13 native corporations owned by 11,000 Inupait shareholders living in remote villages in Alaska. The NANA project has demonstrated the

use of mobile, small footprint drilling and completion equipment for exploration and production in remote areas. The vast resource of unconventional gas, estimated at 1,000 Tcf of coalbed natural gas, shale gas, and tight gas sands is often found in sensitive areas.

Photo credit: Los Alamos National Lab.

Figure 5. *The small size of microhole drilling units can significantly reduce the environment footprint.*

The Slimhole drilling equipment (3.50 inch borehole), all necessary completion fluids and muds, and personnel can be transported by helicopter to individual sites for drilling and well completion. One of the challenges to be met was the selection of an antifreeze, which would allow the borehole to remain open in the permafrost for up to four days. Propylene glycol was selected for its good freeze depression characteristics, lack of health risks, and because it is biodegradable. Transportation of the light-weight drilling equipment and reduced volumes of supplies by helicopter eliminated road building and later reclamation of the surface (**Figure 6**). The small well pad and lack of roads will also reduce wildlife and habitat disturbance. Slimhole drilling and its availability in remote areas will ultimately reduce the use of diesel fuel for power generation, will result in lower-cost, cleaner burning fuel, reduced emissions from trucks, and the reduction of road use to transport the diesel to remote villages.

Photo: Paul Glavinovich, NANA

Figure 6. *Helicopter transport of drilling supplies can eliminate road building to remote sites.*

PRODUCTION

Research and demonstration of new and "best practice" production technologies sponsored by the DOE E&P program in recent years have concentrated on improved recovery efficiency, CO2 sequestration, downhole oil/water separation, and strategies to minimize water production. Demonstrations have focused on strategies and technologies for waterflooding, CO2 floods, steamfloods and monitoring of fluid migration between wells.

BENEFITS:

New processing technologies applied to old seismic data has proven to be a valuable exploration method to comply with environmental regulations, which have halted seismic surveys in some sensitive areas. This means of combining old data with new methods coupled with improved offshore operations can allow development to continue is otherwise restricted areas without harming marine mammals.

Venoco, Inc. of Carpenteria, CA is using modern technologies to continue to explore and produce from offshore areas and to significantly reduce the volumes of produced water that must be disposed of. New seismic reprocessing technology and modeling simulations have allowed Venoco to use data collected from the Santa Barbara Channel over 20 years ago (seismic surveys have been forbidden since 1982) to make discoveries of 80 million barrels of reserves with no adverse impact to the sea mammal population.

Advances in production and drilling using multiple horizontal wells from a single offshore operating platform (**Figure 7**) reduce the surface disturbance at South Ellwood Field. The University of Southern California has developed a model which allows visualization of the subsea reservoir, and identification of the optimal location for wellbores, reducing the number of wells needed to achieve maximum production. The fracture modeling has also been used to identify the seafloor fractures in the Santa Barbara channel, which release gas bubbling to the surface. The collection of gas by concrete seep tents is credited with lowering the gas pressure from the seeps and decreasing the surface oil accumulation, resulting in cleaner beaches and surface waters and healthy marine mammal populations in the Santa Barbara Channel.

Figure 7. *Cleaner water in Santa Barbara Channel attracts seals to Holly Platform.*

Thru-tubing bubble and plug back technology developed by Schlumberger and tested at South Ellwood Field has resulted in a 10-fold reduction of produced water brought to the surface for disposal. The technology allows the drilling operator to pinpoint exactly where in the horizontal wellbore that water and hydrocarbons enter, and has allowed setting bridge plugs to shut off a significant portion of the water producing intervals. The project plans installation of compact oil/water separation units (developed by a DOE project at the University of Tulsa) on Holly Platform as an additional means to manage produced water. This will allow direct reinjection of the produced water to deeper formations, and avoid bringing any waste water onshore for separation and disposal.

BENEFITS:

The Gas Seep tents first built in the Santa Barbara channel by ARCO were designed as method to collect the gas coming from a large active fault in the San Andreas Fault system. The gas collection provided a marketable product, but more importantly it has noticeably cleaned the waters of the Santa Barbara channel, eliminating large spread oil sheen, reducing tar balls on the beach, and resulting is an increased sea mammal population. The new fracture modeling software used with the reprocessed seismic data has led to identification of new seeps, which can now be covered by Seep tents to further benefit the marine and coastal environment.

BENEFITS:

A major goal of DOE's petroleum Environmental solutions program is the beneficial use of byproducts of energy production. Combing the efforts and byproducts of several industries to reduce waste and provide improved production and profits for these companies is an innovative way to approach regional resource problems. Using the waste products from power generation and ethanol production, which resulted in the past in venting heat and CO_2 to the atmosphere, is now providing enhanced oil recovery, and agricultural products

The University of Kansas/Kansas Geological Survey is demonstrating the enhanced recovery and environmental benefits of carbon dioxide injection in the first CO_2 miscible flood demonstration in Kansas at Hall-Gurney field (**Figure 8**). In a combined effort using local resources, an electrical co-generation facility, an ethanol fuel production plant and several agriculture concerns have joined the CO_2 enhanced oil recovery project to form a linked energy system. Waste heat from a 15-metawatt gas-fired turbine municipal generator and CO_2 (a fermentation process byproduct of ethanol production), which would have been vented to the atmosphere, are being beneficially used or sequestered in the subsurface. Additional heat and by-products are used to process wheat and produce cattle feed. CO_2 injection may prevent up

to 6,000 mature oil fields in Kansas from being abandoned. The University's effort to bring the six co-operating companies together has benefited all by increasing productivity, lowering costs, and by reducing pollution of waste gases.

Photo: Alan Byrnes, Kansas Geological Survey

Figure 8. *The proximity of Hall-Gurney field, a new electrical power plant and an ethanol plant at Russell, Kansas contribute to innovate use of byproducts in a linked energy system.*

BENEFITS:

Targeted exploration and drilling technologies can result in higher oil production with both fewer dry holes, and a smaller number of wells drilled. Reservoir characterization of fractured reservoirs has led to innovative production strategies, which can produce significantly more oil while reducing the total number of wells drilled.

Pioneer Natural Resources and Texas A&M University have determining a cost-effective way to waterflood highly fractured clastic reservoirs in the Spraberry Trend. The Spraberry, once referred to as, "The largest uneconomic field in the world" covers over one half million acres in the Permian Basin of West Texas. Low recovery (10%) from the Spraberry Trend with its 8 billion bbl remaining oil-in-place marked it as a target for enhanced oil recovery. The fractured nature of the reservoir had made previous waterfloods only marginally successful, precluded CO_2 flooding, and resulted in a lack of confidence in the waterflooding. The revised waterflood technology has increased performance 6-fold, and will be applicable to a significant number of leases in the 250,000 sq. mile Spraberry Trend and is estimated to recovery an additional 15% of OOIP over the next 20 years. Environmentally the successful waterflood technology will mean fewer dry holes in the establishment of waterflood patterns and longer production from each well, reducing the number of wells drilled.

BENEFITS:

A major factor in enhanced recovery has always been transportation costs and facilities, pipelines or roads. Enhanced recovery using nitrogen reduces the need to construct pipelines, normally used to carry injectants. On-site production of nitrogen for enhanced recovery means less land distributed by pipelines, roads, and storage facilities.

Binger Operations of Cody, Wyoming is using nitrogen injection and horizontal wells to increase production and reduce the number of wells needed to produce the East Binger Unit in western Oklahoma. Nitrogen has several advantages over carbon dioxide as an injectant for small, local fields. Nitrogen gas is widely available, cost-effective and environmentally superior for miscible floods. Because nitrogen can be produced locally at on-site generation facilities (**Figure 9**), it can be used where there are no close sources of carbon

Photo credit: Gary Walker, NETL

Figure 9. *The on-site nitrogen delivery system reduces the footprint in western Oklahoma by eliminating unnecessary pipelines and roads*

dioxide. The lack of pipelines and transportation costs and associated environmental impacts makes nitrogen injection attractive for small fields.

OPERATIONS

Operational considerations in the recovery of oil and gas are often the economic factors that make or break energy production. Reducing the cost of operation and increasing efficiency is vital to operators from marginal fields to offshore platforms. Issues such as electrical power, targeted drilling, separation of oil/gas/water, and improved monitoring of fluids are critical to success and can significantly reduce the environment impact.

BENEFITS:

California air quality standards are high and meeting them is a challenge to producers. Historically waste gas has been flared adding to pollution. Current regulations call for disposal of waste gases. The added value of finding a beneficial use for waste gas avoids the cost of disposal, reduces pollution and provides a cost-effective means to power on-site utility needs.

The California Oil Producers Electricity Coop (COPE) is working with the Interstate Oil and Gas Compact Commission (IOGCC) to demonstrate that existing proven distributed generation technologies, utilizing flare and waste gases as a fuel source, can be applied to generate electricity at marginal well sites. The project is improving the economics of production and decreasing the demand on California's electrical grid. Marginal oil wells in California produce some gas, but not in sufficient quantities to be commercial. The gas becomes a by-product that has to be managed or disposed of some way, using it to run generators will provide power to operate the site. COPE selected a variety of wells producing different amounts and types of gases in Southern California, and different generators to determine those best suited for each well. COPE's demonstration of the first on-site gas powered electrical generation unit is being conducted in Los Angeles. COPE's goal is to reduce air emission to meet Air Quality standards in Southern California, and to reduce production costs so that marginal wells can continue to be economically operated by independents.

BENEFITS:

On-site disposal of waste products is also an important cost savings and environmental benefit for producers. The on-site separation of waste streams and oil and gas allows for immediate reinjection of produced water and avoids the potential problems transporting produced water away from the well site for disposal. Reducing the size and increasing the efficiency of oil/water and gas/water separators makes their use on crowded offshore platforms feasible.

The University of Tulsa working with the Joint Industry Project (JIP) Consortium has developed several refinements for gas-liquid separation and drill cuttings transport of particular use to offshore drilling and production projects in the Gulf of Mexico. The Gas Liquid Cylindrical Cyclone was developed to achieve optimal separation of gas and liquids, in a compact, portable model. The goal is to provide the petroleum industry with a less expensive, more efficient separation alternative to reduce the cost of handling, transporting and processing fluids. The compact size and reduced weight of the unit is ideal for offshore installations yielding a small footprint and allowing for immediate on-site disposal of produced water. The University of Tulsa is currently engaged in the extension of the original GLCC concept (gas-liquid separation) to three-phase flow separation of gas-oil-water.

BENEFITS:

Non-invasive technologies that can monitor water movement are a management tool that will be increasingly valuable for coalbed natural gas development. Coalbed natural gas production results is large volumes of groundwater brought to the surface, much of it is stored in impoundments for beneficial use or infiltration into the subsurface aquifers. The quality of the produced water may be questioned and its containment must be monitored. The ability to trace the movement of the produced water and the natural aquifer waters of an area will assist in management.

NETL-Pittsburgh and the University of Pittsburgh are implementing aeromagnetic surveys of

coalbed natural gas development in the Powder River Basin, Wyoming to monitor groundwater flow. The survey technique uses helicopters to fly over a portion of the Powder River Basin to monitor ground water and produced water flow away from infiltration basins and containment basins. By 2003 over 26,000 coalbed natural gas wells in Wyoming have produced 1 billion cubic feet of natural gas and 1.6 million barrels of water creating a challenge to the oil and gas industry as well as federal and state regulators. Ground water movement is monitored using airborne electromagnetic surveys, GIS to locate positions, and ground conductivity surveys (**Figure 10**) to map near-surface aquifers and produced water plumes. The surveys can identify leaking containment basins several months before a problem is visible to ground personnel. The potential for early detection of leaking containment areas and movement of dissolved salts is a positive environmental benefit in the sensitive Powder River Basin. Information can be used to find and remediate water flow problems, to determine future location for impoundments and groundwater monitoring wells, and to predict water movement allowing coalbed natural gas development to proceed with reduced environmental impact.

Figure 10. *Ground conductivity surveys coupled with aeromagnetic surveys in the Powder River Basin monitor ground water movement.*

CONCLUSIONS

Exploration and production technologies for the petroleum industry are developed primarily to increase oil recovery and reduce the cost of recovery. Reducing costs often goes hand and glove with reducing the environmental impact of exploration, drilling and completion procedures. The industry search for advanced technology to produce oil and to meet environmental regulations has developed new, improved techniques and strategies which accomplish both goals. Conducting operations that are *"Smarter, Farther, Deeper, Cleaner and Smaller"* makes good business sense and helps to protect the environment. Many oil companies have learned that going that one step farther to protect sensitive environments and avoid pollution, pays them back in increased benefits and improved public relations.

The selected E&P projects from DOE's oil program highlight some of the kinds of technologies and innovative strategies being used in mature US oil fields to increase production cost-effective ways that have environmental benefits. The impact of advanced technologies for exploration, drilling, production and oilfieldd operation can be seen in reduced footprint, reduced air pollution, better monitoring of fluids to prevent loss or pollution, and on-site recycling of energy byproducts to reduce unnecessary pipelines and roads. For more details on these projects, visit the Recent Project Success - Fact Sheets at www.npto.doe.gov

Nominations are being taken for the 2004 Chairman's Stewardship Awards
Honoring the Oil & Gas Industry's commitment to Environmental Stewardship

The Interstate Oil and Gas Compact Commission 2004 Chairman's Stewardship Awards. The winners will be honored at the IOGCC Annual Meeting in Oklahoma City, Oklahoma, Oct. 17-19, 2004. You may nominate your company or organization, or any group that has made a contribution in one of the following categories:

- Major Company
- Independent Company
- Energy Education
- Environmental Partnership

To submit a nomination, contact Alesha Riggle at 405.525.3556, ext. 114. Log on **www.iogcc.state.ok.us** for more information and to see past recipients. Deadline for accepting nominations is August 23, 2004.

Upcoming Events/Meetings

Jan. 30-Feb. 2, 2005, Gas Technology Institute (GTI), *Technology Need and Operational Issues of the Natural Gas Industry*, Orlando, FL, (847) 768-0842 Fax, **www.ngt2005@gastechnology.org**

Oct. 12-15, 2004, International Petroleum Environmental Conference (IPEC), *Issues and Solutions in Exploration, Production and Refining*, Albuguerque, NM **http://ipec.utulsa.edu**

Visit our website for more information about DOE's Environmental Programs

http://www.netl.doe.gov

EoE features highlights of DOE's Oil and Gas Environmental Research Program.

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Photo credit: Kirk LaGory

DOE Research Partners

INTRODUCTION

The U. S. Department of Energy's (DOE) Office of Fossil Energy's oil and gas environmental program has agreements with several other federal, state, and non-profit agencies to respond to the environmental needs associated with domestic energy resources. The program develops work initiatives in the areas of water management and also in access to petroleum resources on Federal lands. The activities of our research partners are a part of that activity that will impact those work efforts. Currently, DOE has joint efforts with the Department of Interior's Bureau of Land Management (BLM), the Interstate Oil and Gas Compact Commission, (IOGCC), the Ground Water Protection Council (GWPC), and the Petroleum Environmental Research Forum (PERF).

SYNERGISTIC PARTNERSHIPS - DOE, BLM, IOGCC, GWPC, AND PERF

Environmental protection and economic development of public (Federal) lands in the United States is the responsibility of the DOE and the BLM. Mutual cooperation between these two stewards of national assets results in multiple perspectives, broader areas of consideration and beneficial solutions for the American public.

DOE partners with IOGCC, a 30-state member organization. IOGCC's primary goal is to promote conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety and the environment.

In conjunction with the GWPC's Research Foundation, DOE focuses on the protection and conservation of ground water. GWPC is a nonprofit organization whose members consist of state and federal ground water agencies, industry representatives, environmentalists and concerned citizens, all of whom come together within the GWPC organization to mutually work toward the protection of the nations ground water supplies. The purpose of the GWPC is to promote and ensure the use of best management practices and fair but effective laws regarding comprehensive ground water protection.

DOE's relationship with PERF is a natural partnership in providing a stimulus to and a forum for the collection, exchange, and analysis of research information relating to the development of technology for health, environment & safety, waste reduction and system security in the petroleum industry.

Research Partners Issue

Winter 2003, Vol. 8, No. 1

This edition of Eye on Environment highlights DOE research partnerships with other federal and state agencies, and non-profit organizations.

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The synergistic value of these partnerships should not be underestimated. Sharing resources (expertise, data, and scientific results/research) saves time, taxpayers dollars and produces excellent results/comprehensive solutions.

DOE's Oil Program Objectives

• To move our Nation toward a reliable, economic oil supply, enhance U.S. technological leadership and protect the environment.

• To promote the domestic oil resources to their fullest potential, contributing to the Nation's energy security, economic growth, environmental quality, and science and technological leadership. A key contributing factor in the success of the oil program is the customer-driven approach to public-private partnerships which contribute to the development of technologies, regulatory streamlining, and policies that support increased oil supplies.

BLM

BLM and DOE have had several cooperative agreements in recent years sharing the mutual goals of working to protect the environment while supporting the Presidents' goal of increasing domestic oil and gas production. Previous issues of the *Eye on Environment* (2002) were devoted to cooperative projects with BLM: air monitoring and wildlife habitat studies (Vol. 7 No. 1), and water handling (Vol. 7 No. 2). Currently joint projects are looking at air, water and habitat impacts in Alaska, Montana, Wyoming and New Mexico. Two examples show the range of joint research.

Impact Study of Compressor Noise on Passerine Birds for the U. S. Bureau of Land Management

The effect of noise from gas well compressors on breeding bird populations was studied in the Rattlesnake Canyon Habitat Management Area in San Juan County, New Mexico. BLM administers 18,000 active gas wells in the San Juan Basin in an area of 1.5 million acres of land. Large gas-fired compressors (**Figure 1**) are used to increase the efficiency of gas extraction and pressurize gas pipelines on many of the wells in the basin. The noise produced by these compressors has prompted concern for its potential to affect wildlife populations in adjacent habitats.

Photo credit: Kirk LaGory

Figure 1. Large gas-fired compressor used in gas extraction.

The Rattlesnake Canyon study area is a piñon juniper habitat and home to a number of bird species during the breeding season. The survey area was laid out along 400 meter linear transects designed to pick up the range of compressor noise from low to moderate to the well pad site. Forty-six bird species were observed during the study (37 species on control sites and 42 on compressor sites). In general, the number of birds per species and the total number of birds observed tended to be higher on control sites than treatment sites. This frequency appeared to be significant only for one species, the spotted towhee (**Figure 2**). The number of birds per 50 meters of transect decreased with distance from the compressors and was consistent with the pat-

tern on the control sites, and only in the strongest noise zone immediate to the compressors were differences in bird populations observed. The spotted towhees were significantly lower (42% fewer) near the compressors and the numbers of house finches and juniper titmice were significantly higher (71% and 167% respectively) than in the same distance interval on control transects.

Photo credit: Kirk LaGory

Figure 2. Spotted Towhee.

The differences apparently reflect species-specific differences in habitat requirements and tolerance to noise. The results indicate that the effect of noise varies among bird species, but is measurable in areas exposed to relatively moderate levels of noise. The effects of compressor noise on bird populations could be reduced by using noise abatement measures to reduce the noise level.

Contact: Kirk LaGory, ANL, Chicago, IL, (630) 252-3169 or lagory@anl.gov. **Performance period:** 6/1999 to 6/2001. **Project Manager:** John Ford, NETL, Tulsa, OK (918) 699-2061 or john.ford@npto.doe.gov.

Evaluation of Phytoremediation of Coal Bed Methane Produced Water and Waters of Quality Similar to that Associated with Coal Bed Methane Reserves of the Powder River Basin, Montana and Wyoming

The Powder River basin in Wyoming and Montana has emerged as one of the most active areas for coal bed natural gas exploration and development. Coalbed natural gas extraction produces an excess of saline and sodium water as a byproduct. This produced water has the potential to elevate the saline and sodium levels in the soil, which may decrease agricultural productivity.

The hypothesis of the project is that specific species of plants can function to uptake the excess salts and remediate the saline and sodium conditions (phytoremediation) associated with coal bed natural gas produced waters.

Certain plants, termed halophytes, are salt tolerant accumulators. These species can accumulate high concentrations of sodium and other salts in above ground tissues, and in some cases, excrete these salts through nodes or on leaf surfaces. The best phytoremediation plants are field crops which can be used in rotation or in combination with similar plant species grown in the area. Field crops used for phytoremediation remove the sodium and soda from the soil permanently as they are harvested annually. For the Powder River basin–barley, wheat, sorghum, cotton, and sugar beet are being tested for their use in phytoremediation of saline-sodic soils. The project is also looking at 12 other grasses and shrubs which are specific for sodium-sodic adsorption. These species may grow well in the ranching areas of the Powder River basin (**Figure 3**).

Photo credit: James Bauder

Figure 3. Laboratory tests at Montana State University facilities show plants growing in soils watered with coalbed natural gas-produced water.

Contact: James Bauder, MSU, Bozeman, MT (406) 994-5685 or jbauder@montana.edu. **Performance period:** 9/2001 to 8/2006. **Project Manager:** John Ford, NETL, Tulsa, OK (918) 699-2061 or john.ford@npto.doe.gov.

IOGCC

The Interstate Oil and Gas Compact Commission represents the governors of 30 states. These states produce all the domestic oil and natural gas in the United States.

The mission of IOGCC is to provide "an organization of states which promotes conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety and the environment."

"The governors of our member states have long stood for conservation and environmental protection in the area of domestic oil and natural gas," said IOGCC Executive Director Christine Hansen.

Strategic partnerships with organizations like the DOE are important tools for the IOGCC to accomplish its work, and are of obvious benefit to America's oil and natural gas industry.

> *"Every barrel of oil or MCF of natural gas, produced domestically meets the nation's growing demand for energy while helping to reduce the need for importing oil."*
>
> – Christine Hansen,
> IOGCC Executive Director

The closely allied goals of IOGCC and DOE make their working together on environmental and regulatory topics vital. In a recent statement IOGCC Director, Christine Hansen, discussed the value of marginal wells, "Marginal oil wells make up 29% of our domestic oil production – and that's significant." The nation can not afford to plug and abandoned this resource. Speaking of oil and gas reserves on western public lands, Hansen reminded the press that, "Every barrel of oil or MCF of natural gas, produced domestically meets the nation's growing demand for energy while helping to reduce the need for importing oil."

IOGCC, working with DOE, has helped to develop and promote advances in technology that assists industry in extracting oil and natural gas while minimizing the impact on the environment. Speaking on the issue of access to public lands, Hansen said, "No one is arguing for ruining our environment and despoiling wilderness areas. But if we want to maintain our quality of life and make our nation more secure, we have to understand that access to oil and natural gas on public lands is very important."

Distributed Generation Electrical Power Units at Marginal Oil Well Sites

The IOGCC, working with the California Oil Producers' Electric Cooperative (COPE), will demonstrate and evaluate the economic feasibility of using modern Distributed Generation Power Units to create low-cost electricity for powering marginal oil well pumping units in southern California oil producing regions. This innovative distributed generation project will reduce the cost of oil production – thereby extending the economically productive life of critical domestic oil supplies. This project is a DOE PUMP III environmental award.

The primary goal of this project is to boost domestic oil production by 75,000 barrels per day (28 million barrels per year) within the next 10 years. How? By preventing the waste of these valuable domestic oil resources through premature plugging and abandonment, or shutting down of marginal oil wells due to economic and regulatory constraints.

Based on an analysis by COPE, 40 to 60 percent of today's cost of oil production and delivery is the cost of electricity. The objective of this project is to increase oil production by utilizing flare and shut-in gas from California's oil fields to generate valuable low-cost electricity, displacing high-cost grid power. A successful project will extend the productive life of marginal oil wells and thereby aid in reducing our country's reliance on uncertain foreign oil sources.

Project goals include:

- Reduce our foreign trade deficit, and depend-

ence on foreign oil
- Lower unemployment
- Reduce greenhouse gases and NOx emissions
- Generate additional revenues for local, state and federal governments.

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Building Partnerships with Results: Interstate Oil and Gas Compact Commission Multi-State Funding
The objective of this project is to expand a number of ongoing environmental projects in the oil and gas producing states. Projects include technical and training assistance, regulatory streamlining, data management standardization and discussions of regional oil and gas issues. Specific tasks in the project involve:
- Database standardization - improve uniformity of state oil and gas data management systems
- Training – conduct environmental compliance workshops
- Appalachian - Illinois Basin; regulatory efficiency through partnering with agency directors
- Regulatory streamlining – including the identification and elimination of unnecessary duplication of effort between state and federal programs on public lands.
- North American Coastal Alliance – involves the states, and the provinces of Canada that have offshore petroleum in a shared regulatory alliance to identify areas of concern and standard practices for offshore environmental and regulatory compliance.
- Environmental and Technical Assistance – promote development and implementation of risk-based environmental regulation by the states.
- Toxics Release Inventory – coordinate with the Environmental Protection Agency (EPA) to ensure adequate information is available to the public.
- Public Education and Outreach – demonstrate leadership in educating the public about oil and gas exploration and production methods, and the economic value of domestic petroleum, conservation efforts and the benefits to the American public.

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GWPC

"The Ground Water Protection Council is a national association of state ground water and underground injection control agencies whose mission is to promote the protection and conservation of ground water resources for all beneficial uses, recognizing ground water as a critical component of the ecosystem." GWPC provides a forum for communication and research in order to improve the role state and federal government plays in the protection and conservation of ground water. Ground water provides 55% of the population's drinking water, is used to supply the needs of industry and agriculture, and may directly influence the quality of surface water.

GWPC policy elements:
- Prevent ground water contamination
- Promote safe and responsible use of underground injection for waste disposal
- Promote ground water as a resource requiring protection for current and future use
- Promote participation in GWPC by local, state, federal governments and industry
- Utilize academia, industry and government for technical, educational, financial and research support to achieve these policies.

Advancing Technology and Methodology to Streamline Environmental Compliance is a 3 year project conducted by GWPC. This represents a project in which DOE has funded GWPC to provide assistance to State agencies and the oil and gas industry with data management and regulatory streamlining. The development of a Risk-Based Data Management System (RBDMS) is designed for use on personal computers to allow improved data management.

Part of the original funding was for the development of Cost-Effective Regulatory Approach projects. Three main tasks are involved (1) install the

RBDMS in all state oil and gas agencies that want to use the system and provide customized assistance in its use, (2) continue to advance the capabilities of RBDMS, and (3) use peer reviews and a National Forum on Water Re-Use issues to improve regulatory streamlining. A new effort will begin the collection of environmental data on hydraulic fracturing of coal beds.

As of 2002, 18 state agencies were using the RBDMS software to handle a significant amount of all or their data management needs. In addition several states have requested assistance to upgrade the RBDMS utility or to train personnel. Part of the tasks under this project will be to develop a user and administrative manual which will allow agencies to train new personnel and document procedures. New customized updates available include on-line permitting, generic field mapping, inspections and pressure tests, scheduling inspections, improving inspectors time management and data recording, evaluation for taxation purposes, and electronic reporting requirements.

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Cost-Effective Approaches to Enhance Domestic Oil and Gas Production and Ensure the Protection of the Environment provides assistance to oil and gas agencies and producers in individual states to develop environmental risk management practices and to assist in direct implementation. Area of Review (AOR) variance programs will also be established and both large and small producing companies will be assisted in meeting Class II injection well AOR requirements.

Two detailed RBDMS pilots were conducted in the Williston Basin (in parts of Montana, North Dakota and South Dakota), and in the Dorr field waterflood in Kansas. The pilots included a nationwide survey and needs assessment survey, which revealed that 24 states were interested in the RBDMS project and requested assistance. Many states also expressed interest in expansion of the RBDMS capabilities. This DOE award will allow GWPC to provide assistance and revise the RBDMS format to accommodate the response from the states. States which will be assisted under the award include; Kansas, Oklahoma, Ohio, California, Colorado, Alabama, Texas, New York, Louisiana and New Mexico.

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PERF

"The Petroleum Environmental Research Forum is a research and development joint venture whose members are corporations engaged in the petroleum industry that recognize the importance of a clean, healthy environment and are committed to supporting cooperative research and development". PERF provides a forum for members to collect, exchange, and analyze research information relating to practical approaches to science and technology, and the environment in the petroleum industry.

PERF started in 1986 as a multidisciplinary group of scientists, engineers and managers with interests in petroleum and the environment. The PERF members are all volunteers from member companies. An eight member Board of Directors assists in coordination between research and development projects in industry and government agencies. PERF meetings are held quarterly, and representatives from other trade associations and such government agencies as DOE and the National Laboratories are invited to participate. Projects typically have from two to six or ten participants and the actual research work may be performed by a university, National lab, independent contractor or by a PERF member company.

PERF Objectives

- To provide a stimulus for cooperative research and development of technology for the environment, health, safety, waste reduction and system integrity for the petroleum industry.

• To provide a forum to discuss and develop proposals for cooperatively funded projects relating to these areas.

Highlights of several current DOE/PERF projects indicate the range of overlapping interest and cooperation.

Evaluation of Slurry Fracture Injection Technology conducted by Argonne National Laboratory with the participation of ChevronTexaco, ExxonMobil, ConocoPhillips and Unocal. The objective of the research is to evaluate various injection technologies used for disposal of solid oil field wastes. Emphasis is on slurry fracture injection techniques. The project team began with a complete review of the literature on slurry fracture injection and then contacted state officials for information on injection activities and to learn about each state's injection permit practices. **Figure 4** illustrates mixing equipment and an injection well as part of slurry technology designed by Terralog Technologies under a DOE contract.

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Physiologically-Based Extraction Protocol to Determine Bioavailability and Health Hazards of Petroleum Products from Soils to Humans performed by Lawrence Berkeley National Laboratory is designed to investigate the exposure pathway from hydrocarbons in soils to absorption by humans. Exposure to hydrocarbon residues at petroleum-contaminated sites poses a risk to human health by skin absorption and accidental windblown soil ingestion. Exposure may affect long term and expensive cleanup goals at these sites. The research focuses on *in vitro* gastrointestinal protocol in order to quantitatively determine the valid indicators of human exposure to residual petroleum hydrocarbons in soils. *In vitro* work has shown that only a fraction of the hydrocarbons in ingested soils would cross the intestinal membranes and enter the systemic circulation.

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Photo credit: Michael Bruno

Photo credit: Michael Bruno

Figure 4. Injection well (above) and mixing and pumping equipment.

An Ecological Framework to Evaluate Impacts of E&P Releases performed by Lawrence Livermore National Laboratory (LLNL). The goal of the project is to develop and improve methods for ecological risk evaluation and assessments on an ecosystem or ecoregion scale, and to reduce the protocol required at small, remote sites. The specific pur-

pose is to investigate the role of size and spatial distribution of small contaminated sites, and assess their impact on the larger ecosystem.

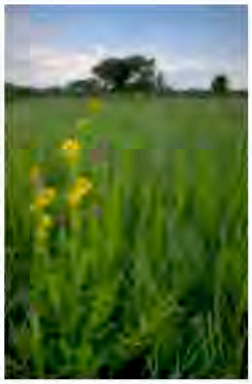

Photo credit: Harvey Payne

Figure 5. Tall Grass Prairie Preserve, OK.

State and federal agencies frequently require ecological risk assessments (ERA's) to estimate such impacts. The petroleum industry has thousands of sites which may be impacted by the release of petroleum-related products and brines to various degrees, and the ERA's are very complex and time consuming to file, particularly for small independent producers. Many of these sites will be abandoned and, if in remote locations, will not be a risk to human health. The effort of the ERA's may not be necessary at all sites, and such ecotoxicolgically based ERA's at each isolated, impacted area may provide a misleading estimate of the impact on populations and communities at larger, more ecologically meaningful scales.

The Tall Grass Prairie Preserve in northern Oklahoma (**Figure 5**) was selected as a representative E&P facility or ecosystem. The protocol will develop the use of GIS for data assessment for E&P sites and greatly facilitate cost-effective means for evaluating ecological impacts within ecosystems.

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eye on environment

EoE features oil- and gas-related projects implemented through DOE's oil and gas environmental research program.

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Upcoming Events/Meetings

May 18-21, 2003, Interstate Oil and Gas Compact Commission (IOGCC), *Midyear Meeting, State Leadership in a Global Environment*, Williamsburg, VA, www.iogcc.state.ok.us

June 2-4, 2003, Petroleum Environmental Research Forum (PERF), *62nd Quarterly Meeting*, Paris, France. www.perf.org

June 5-6, 2003, Powder River Basin Organization, *CBM Information Fair*, Gillette, WY, www.powderriverbasin.org

September 13-17, 2003, Ground Water Protection Council (GWPC), *Annual Forum*, Niagara Falls, NY, www.gwpc.org

October 19-21, 2003, Interstate Oil and Gas Compact Commission (IOGCC), *The Challenge of Energy Policy, Annual Meeting*, Reno, NV, www.iogcc.state.ok.us

November 11-15, 2003, International Petroleum Environmental Conference (IPEC), Houston, TX, www.ipec.ens.utulsa.edu