Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries

An ENERGY STAR® Guide for Energy and Plant Managers

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United States Environmental Protection Agency

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ABSTRACT

The petroleum refining industry in the United States is the largest in the world, providing inputs to virtually all economic sectors, including the transportation sector and the chemical industry. The industry operates 144 domestic refineries (as of January 2012), employing over 63,000 employees. The refining industry produces a mix of products with a total value exceeding $555 billion. Although refineries typically spend 50% of cash operating costs (i.e., excluding capital costs and depreciation) on energy, recent developments in natural gas prices have reduced this to approximately 30%. Even with these savings, energy remains a major cost factor and an important opportunity for cost reduction. Energy use is also a major source of emissions in the refinery industry, making energy efficiency improvement an attractive opportunity to reduce emissions *and* operating costs.

Voluntary government programs aim to assist industry to improve competitiveness through increased energy efficiency and reduced environmental impact. ENERGY STAR®, a voluntary program managed by the U.S. Environmental Protection Agency, stresses the need for strong and strategic corporate energy management programs. ENERGY STAR provides energy management tools and strategies for successful corporate energy management programs. This Guide describes research conducted to support ENERGY STAR and its work with the petroleum refining industry.

This Guide introduces energy efficiency opportunities available for petroleum refineries, beginning with descriptions of the trends, structure and production of the refining industry and the energy used in the refining and conversion processes. Specific energy savings for the energy efficiency measure are provided, based on case studies of plants and references to technical literature. If available, typical payback periods are also listed. The Guide draws upon the experiences with energy efficiency measures of petroleum refineries worldwide. The findings suggest that, given available resources and technology, there are opportunities to reduce energy consumption cost-effectively in the petroleum refining industry while maintaining the quality of the products manufactured. Further research on the economics of the measures, as well as the applicability of these measures to individual refineries, is needed to assess the feasibility of implementation of selected technologies at individual plants.

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1. Introduction

As U.S. manufacturers face an increasingly competitive global business environment, they seek out opportunities to reduce production costs without negatively affecting product yield or quality. Uncertain energy prices in today's marketplace negatively affect predictable earnings, which are of particular concern to publicly traded companies in the petroleum industry. The substantial decline in natural gas prices over the past year has provided a competitive advantage to both U.S. public and private industry. Successful, cost-effective investment into energy efficiency technologies and practices meets the challenge of maintaining a high quality product output while reducing production costs and mitigating the risk posed by volatile energy prices. These investments also frequently yield broader additional benefits, such as increasing the overall productivity of the company.

Energy use also constitutes a major source of emissions in the refinery industry, making energy efficiency improvement an attractive opportunity to reduce both emissions *and* operating costs. End-of-pipe solutions can be expensive and inefficient, while investing in energy efficiency as part of a comprehensive environmental strategy can provide an inexpensive opportunity to reduce criteria and other pollutant emissions. Such investments can also prove an efficient and effective strategy to work towards the "triple bottom line" that focuses on the social, economic, and environmental aspects of a business.[1] In short, energy efficiency investment is sound business strategy in today's manufacturing environment.

Voluntary government programs aim to assist industry and improve competitiveness through increased energy efficiency and reduced environmental impact. ENERGY STAR®, a voluntary program managed by the U.S. Environmental Protection Agency (EPA), highlights the importance of strong and strategic corporate energy management programs. ENERGY STAR provides energy management tools and strategies for successful corporate energy management programs. This Guide supports ENERGY STAR and its work with the petroleum refining industry by describing research on potential energy efficiency opportunities for refineries. ENERGY STAR can be contacted through www.energystar.gov for additional energy management tools that facilitate strong energy management practices in U.S. industry.

The United States has the largest petroleum refining capacity in the world, providing inputs to virtually all economic sectors, including the transportation sector and the chemical industry. The industry operates 144 domestic refineries (as of January 2012), employing over 63,000 employees, and producing a mix of products with a total value exceeding $555 billion (based on the 2010 Annual Survey of Manufacturers). Although refineries typically spend 50% of cash operating costs (i.e., excluding capital costs and depreciation) on energy, recent developments in

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[1] The concept of the "triple bottom line" was introduced by the World Business Council on Sustainable Development (WBCSD). The three aspects of the "triple bottom line" are interconnected as society depends on the economy and the economy depends on the global ecosystem, whose health represents the ultimate bottom line.

natural gas prices have reduced these expenditures by approximately 20%. Even with this substantial reduction, energy remains a major cost factor and an important opportunity for cost reduction for industry.

This Guide first describes the trends, structure and production of the petroleum refining industry in the United States. It then describes the main production processes. Next, it summarizes energy use in refineries, along with the main end uses of energy. Finally, it discusses energy efficiency opportunities for U.S. refineries, additional GHG abatement technologies, and opportunities for water management. The Guide focuses on measures and technologies that have been successfully demonstrated within individual plants in the United States or abroad. Due to the complexity of the petroleum refining industry, this Guide cannot cover all possible energy efficiency opportunities for refineries. While this Guide primarily focuses on practices that are both proven and currently commercially available, Section 19.4 briefly discusses a selection of new and innovative technologies that are currently in development.

This Guide aims to serve as a guide for energy managers and decision-makers, helping them develop efficient and effective corporate and plant energy management programs by providing information on new or improved energy-efficient technologies.

2. The U.S. Petroleum Refining Industry

The United States has the world's largest refining capacity, processing just less than a quarter of all crude oil in the world. Although the major products of the petroleum refining sector are transportation fuels, its products are also used in other energy applications, and as feedstock for chemical industries.

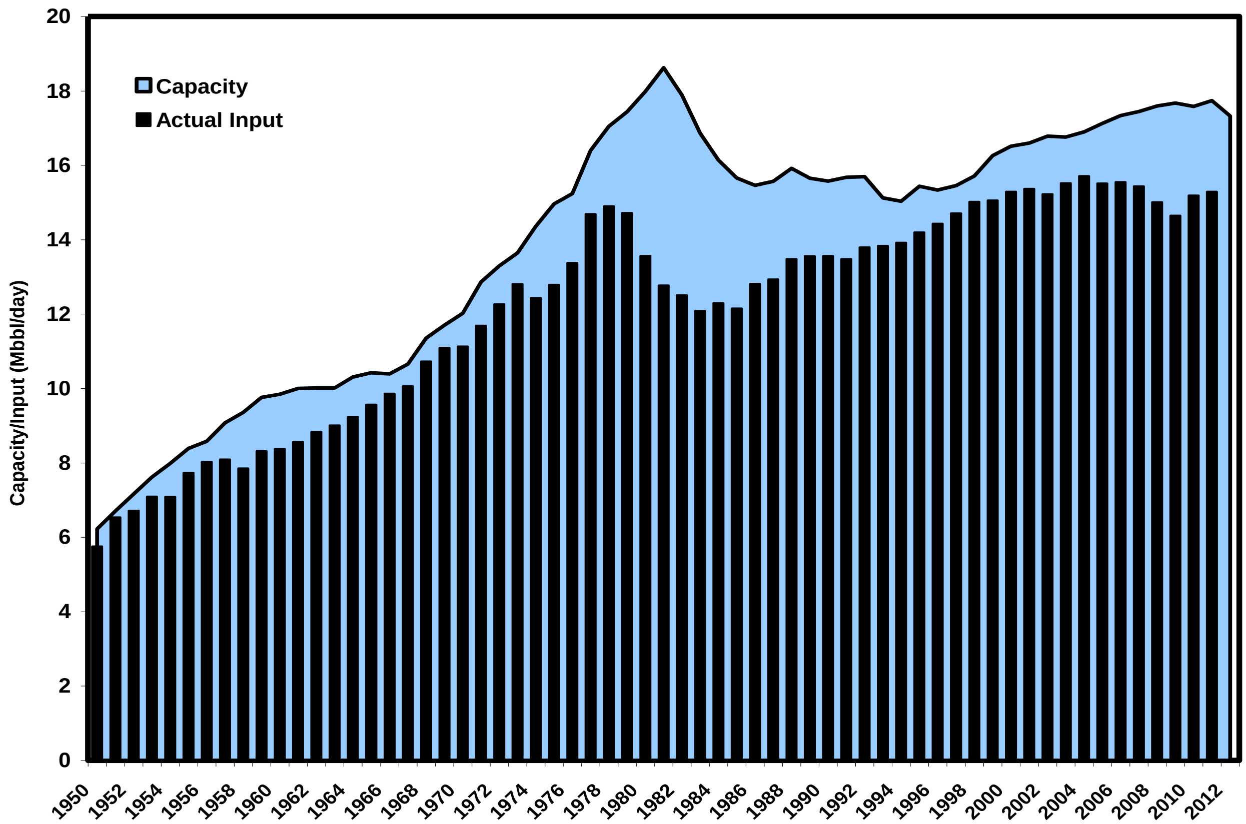

Figure 1. Capacity and actual crude intake of the U.S. petroleum refining industry between 1950 and 2012, expressed in million barrels/day of crude oil intake. ***Source: Energy Information Administration.***

The U.S. petroleum refining industry has grown over the past 60 years by about 2%/year, on average. Although refining capacity grew rapidly until the second oil price shock, production began to level off in the mid to late 1970s. This industry underwent a period of substantial reorganization, and did not resume growth until after the mid-1980s. From 1985 to 2001, the industry grew at a somewhat slower rate of 1.4%/year, with refinery input stabilizing after 2001. Despite this stabilization, refinery capacity again continued to grow, reaching its highest level in nearly three decades by 2011 before dropping in 2012. Figure 1 shows the developments in installed capacity (expressed as crude intake capacity) and actual crude intake in the U.S. refining industry since 1950.

Figure 1 shows that capacity utilization has been relatively stable, with the exception of the period between the two oil price shocks and the period after 2007. Following the first oil price shock, federal legislation favoring domestic production and refining subsidized the construction and operation of many small refineries (U.S. DOE-OIT, 1998b). This led to a reduced capacity utilization. After 2007, the U.S. recession caused lower petroleum demand, pushing down domestic refining operations to 83 percent of capacity by 2009. Although the capacity utilization rate increased to approximately 86 percent in 2011, it remains well below the levels seen from 1993 through 2005.

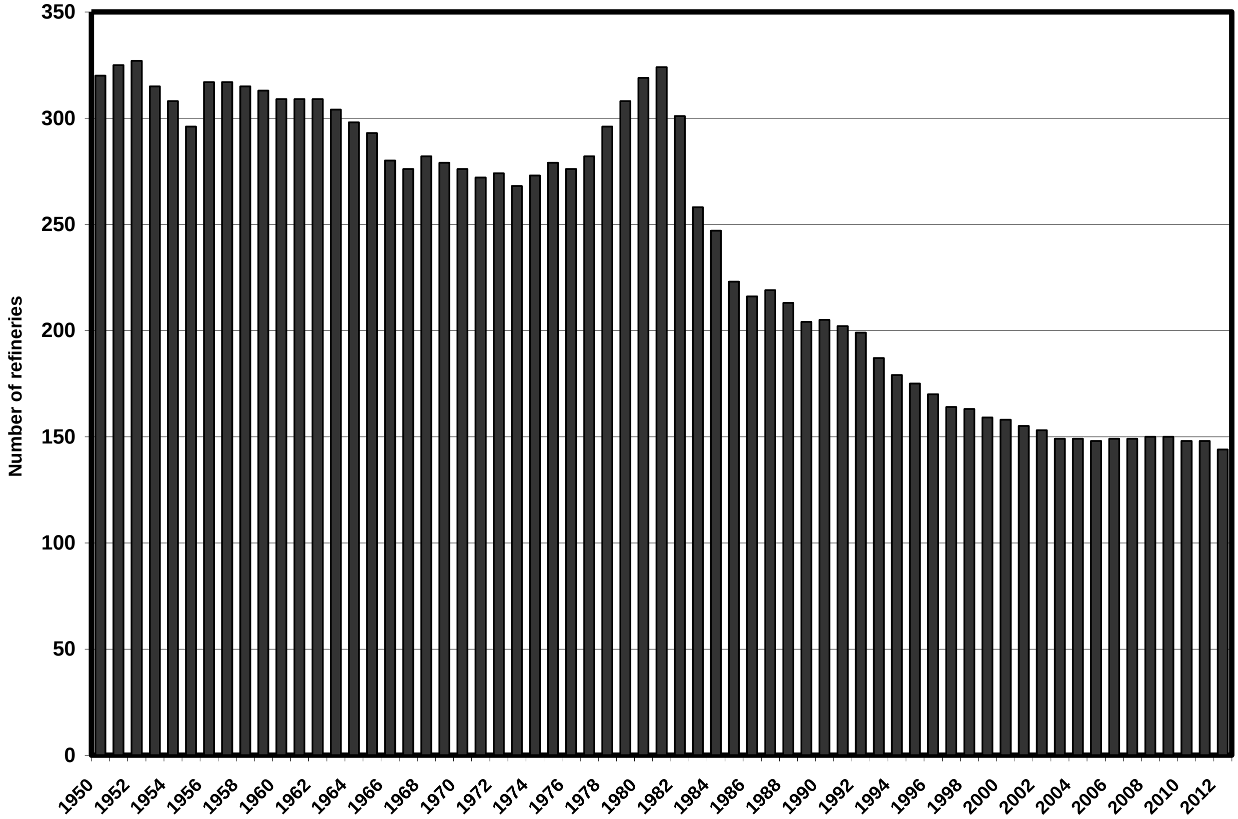

Figure 2. Number of operating refineries in the United States. ***Source: Energy Information Administration.***

Figure 2 depicts the number of operating refineries in the United States since 1950. It clearly demonstrates the increasing number of refineries after the first oil price shocks in the 1970s. Small refineries only distill products, and are most often inefficient and less flexible operations, producing only a small number of products. Increasing demand for lighter refinery products and changes in federal energy policy have led to a reduction in the number of refineries, while increasing capacity utilization (see Figure 1).

These market dynamics will lead to the further concentration of the refinery industry into high capacity plants operating at higher efficiencies. The number of operating refineries has declined from 205 in 1990 to 144 in 2012, but has been stable over the past decade. Current capacity growth primarily results from the expansion of available refinery capacity (i.e., capacity creep). The need to produce cleaner burning fuels to meet environmental regulations (e.g., reduction of sulfur and benzene content) will increase the need to install new equipment. These environmental regulations have contributed to the shutdown of new refinery construction over the past decades (U.S. DOE-OIT, 2007). Appendix A provides a list of operating refineries in the United States as of January 2012.

Petroleum refineries are located in 31 states, though the industry is heavily concentrated in a few states due to historic resource distribution and easy access to imported supplies (i.e., close to harbors). Hence, the largest number of refineries can be found on the Gulf coast, followed by California, Illinois, Washington, and New Jersey. Some of the lowest producing states have only very small refineries administered by independent operators. These refineries produce a very limited mix of products, and are ultimately not expected to be able to compete in the developing oil market. Figure 3 depicts 2012 refining capacity by state, expressed as share of total capacity crude intake.

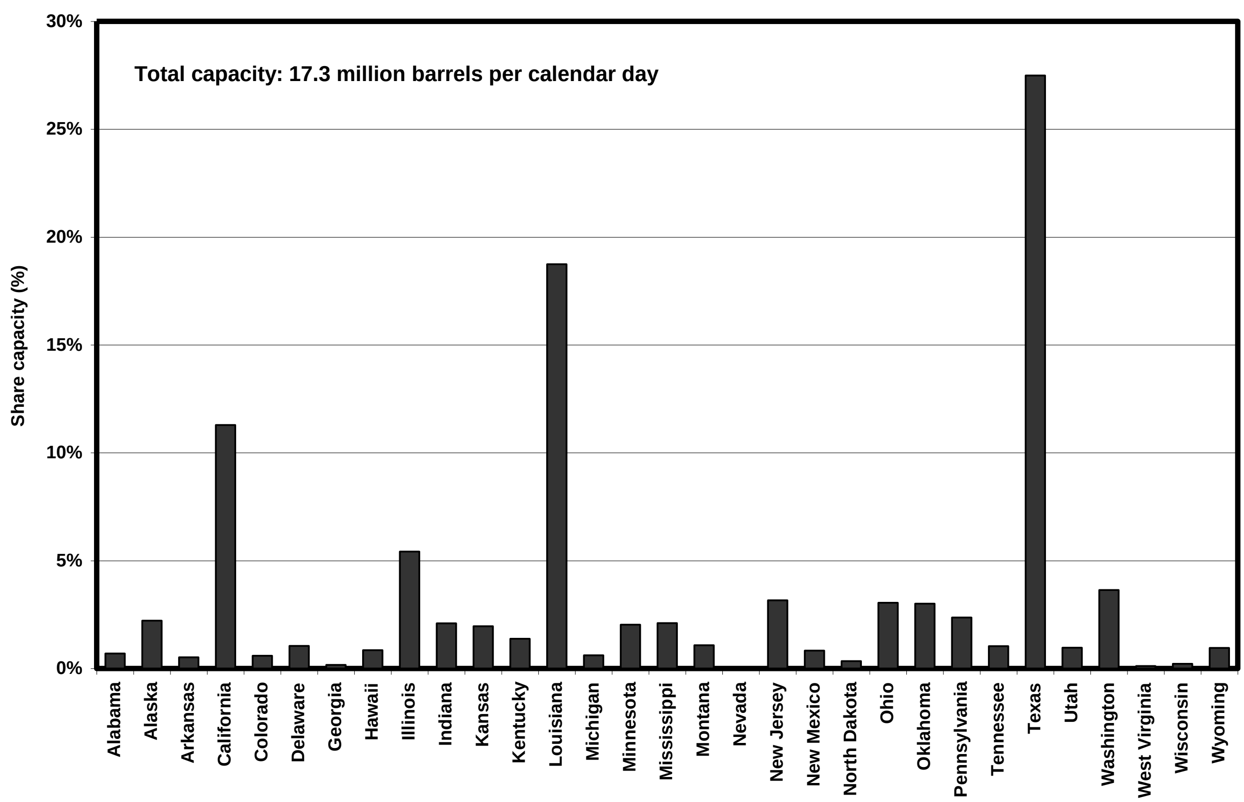

Figure 3. Refining capacity by state as share of total U.S. refining capacity in 2012. ***Capacity is expressed as capacity for crude intake. Source: Energy Information Administration.***

There are 67 companies in the United States currently operating refineries. Although there are a relatively large number of independent companies in the U.S. refining industry, the majority of the refining capacity is operated by a small number of multi-national or national oil processing companies. The largest companies (as of January 2013) are: Valero (11% of crude capacity), ExxonMobil (11%), Phillips 66 (9%), BP (8%), Marathon (7%), Motiva (6%), and Chevron (6%), which combined represent 48% of domestic crude distillation (CDU) capacity. Each of these companies operates a number of refineries in different states. Figure 4 depicts companies operating over 0.5% of total domestic CDU capacity.

Small refineries frequently use high cost feedstock and produce a relatively simple product mix, which may result in lower profitability when compared with larger refineries. As a result, small companies' share of total industry economic value is lower than their share of total industry production capacity.

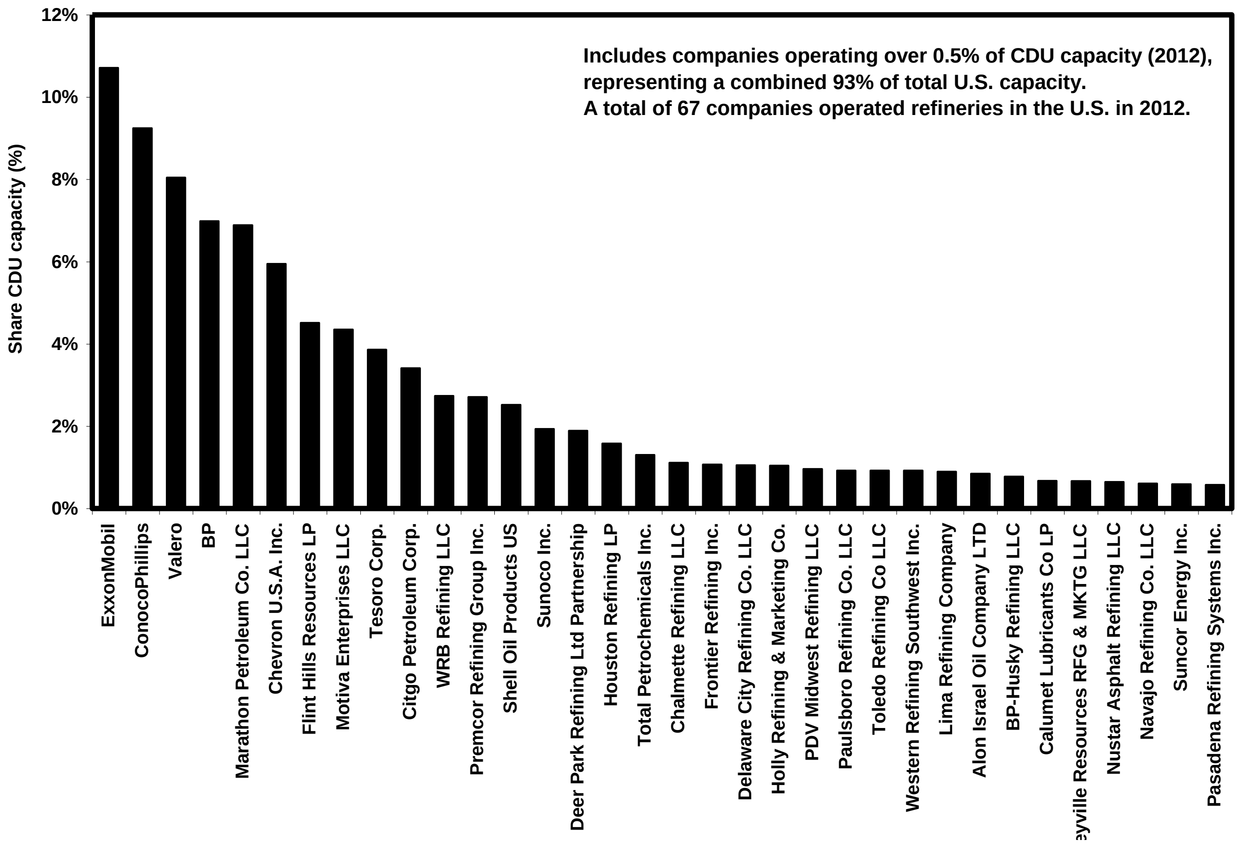

Figure 4. Refining capacity (expressed as percentage of total CDU capacity) for companies operating over 0.5% of total CDU capacity in 2012. ***The depicted companies operate 93% of total national capacity. Companies operating 0.5% or less of total CDU capacity are not depicted. Refineries may change ownership and increase capacity. Current capacity distribution may be different. Source: Energy Information Administration.***

The further concentration of refineries in the United States has contributed to a reduction in operating costs, but has also impacted refining margins (Killen et al., 2001). The western United States market is largely isolated from the other primary oil markets in the United States. Although overall market dynamics in the United States and the western United States markets follow the same path, this isolation results in higher operating margins from western refineries. A second effect of this isolation is that refineries have little access to alternative markets when demand in this region declines.

U.S. refineries process different kinds of crude oil types from different sources. Over the past decade, there has been a trend towards more heavy crudes and higher sulfur content, although newly produced crudes may in fact be lighter. These effects vary for the different regions in the United States.

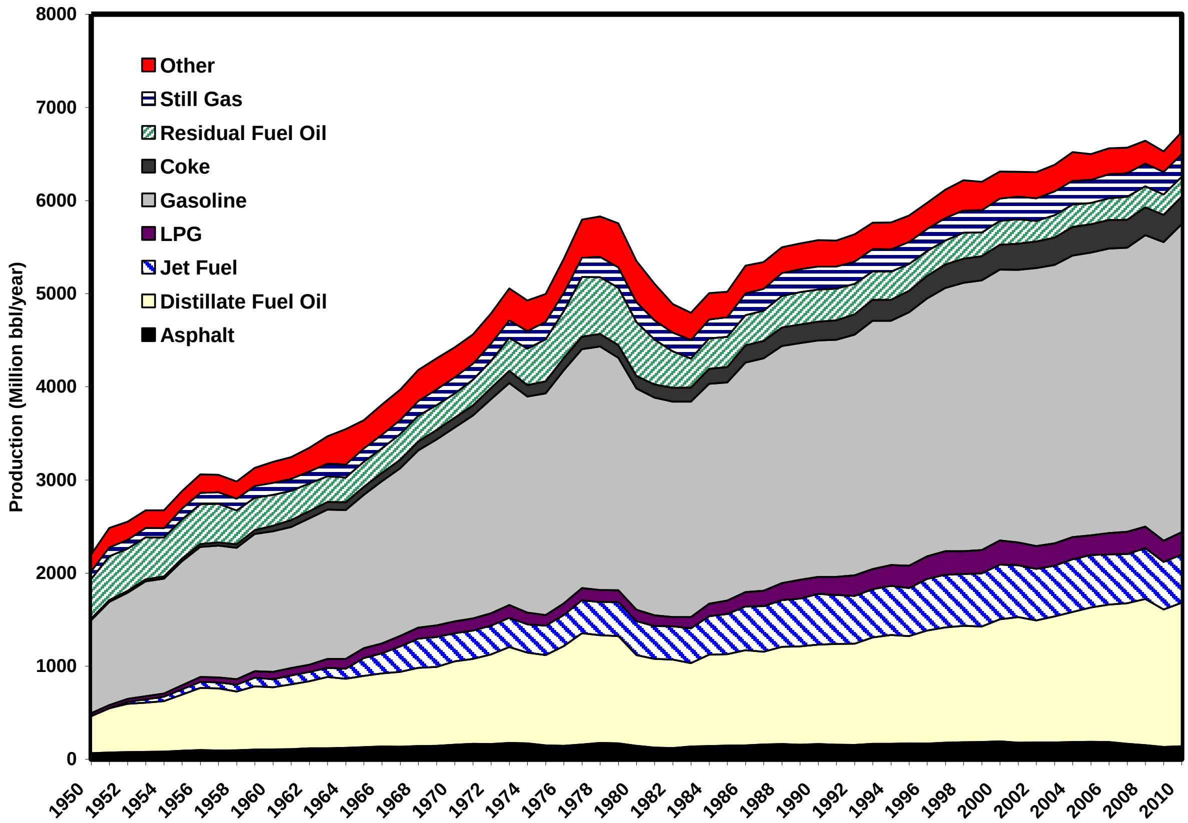

Figure 5. Petroleum refining production, by major product categories in the United States, 1950 – 2010. ***Source: Energy Information Administration.***

Figure 5 depicts the past trend in production since 1950 by product category. This figure shows an increase in the production and relative share of lighter products, such as gasoline, while the share of heavier fuels like residual fuel oil declined over the past several decades. Figure 5 does not show the changing quality demands of the product categories. Started in California, increased air quality demands and emission standards in many parts of the United States resulted in an increased demand for low-sulfur automotive fuels (i.e., gasoline, diesel). Over the past decade, this rising demand has resulted in an increase of hydrotreating capacity of over 40%. Small refineries will most likely not be able to invest in this type of expansion and will lose further market share. With limited markets for the hydroskimming refineries, a further concentration of refineries will likely occur over the coming years. Expansion of existing refineries will provide the increased demand, as new greenfield refinery construction is not anticipated within the United States over the next few years.

The continued trend towards low-sulfur fuels and changes in the product mix of refineries will affect technology choice and needs. For example, current desulfurization and conversion technologies use relatively large quantities of hydrogen. Demand for hydrogen is expected to rise in order to keep pace with ultra-low sulfur fuel demand. Hydrogen is an energy-intensive product, and increased hydrogen consumption will correspondingly increase energy use and operating costs, unless more efficient hydrogen production and recovery technologies are developed and applied. New desulfurization technologies that are being developed and demonstrated and may help to reduce the need for hydrogen include oxidative, biocatalytic, adsorption, and membrane technologies.

At the same time, the dynamic development of the petroleum industry faces new economic and environmental challenges. Increasing and more volatile energy prices will affect the bottom line of refineries while commodity markets, like those of most oil products, show continuously falling margins. Both factors may negatively affect the profitability of petroleum refining. Furthermore, increased needs to reduce air pollutant emissions from refinery operations, the blending of biofuels, other energy related issues (e.g., regulatory changes of power supply), as well as increased safety demands are challenges faced by refineries and will drive technology choice and investments in future process technologies. Climate change and developments in automotive technology are similarly poised to affect the future structure of refineries. Reduced profitability resulting from a combination of these factors is expected to continue, profoundly impacting industry decisions regarding technology. Table 1 summarizes the primary challenges facing the petroleum refining industry.

Table 1. Key drivers and challenges for the petroleum refining industry. The order in the table does not reflect an order of priorities.

Challenge	Key Issues
Safety	Safety incidents, refineries now mainly located in urbanized areas
Reliability	Capacity utilization, profitability, and energy efficiency
Environment	Emissions of criteria air pollutants (NOx, VOC) and greenhouse gases
Profitability	Commodity market, further concentration of the industry
Fuel Quality	Sulfur, MTBE-replacement
Feedstock	Increasing demand for lighter products from decreasing quality crude
Energy	Costs of power

3. Process Description

A modern refinery is a highly complex and integrated system separating and transforming crude oil into a wide variety of products, including transportation fuels, residual fuel oils, lubricants, and many other products. The simplest refinery type is a facility in which the crude oil is separated into lighter and heavier fractions through the process of distillation. In the United States, almost 30% of the refinery facilities are small operations producing fewer than 50,000 barrels/day (EIA, 2012), comprising approximately 4% of the total industry output. The existence of small, relatively inefficient refineries is due in part to legislation subsidizing smaller operations, enacted during the aftermath of the first oil price shock. These small operations typically consist only of distillation capacity (i.e., no reforming or converting capacities) and produce a limited number of products.

Modern refineries have developed much more complex and integrated systems in which hydrocarbon compounds are not only distilled, but are also converted and blended into a wider array of products. The overall structure of the refinery industry has changed in recent years due to a growing demand for lighter products. This has led to an increase in complex refineries with greater conversion capacities. Increased conversion will lead to a corresponding rise in the specific energy consumption, while producing a more valuable array of products. These trends are expected to persist in coming years as demand for heating (fuel) oil decreases.

All refineries must distill crude oil before conversion occurs. The two most important distillation processes are crude or atmospheric distillation and vacuum distillation. Different conversion technologies are available to take advantage of thermal or catalytic processes, such as using a catalytic reformer where the heavy naphtha produced in the crude distillation unit is converted to gasoline, or a fluid catalytic cracker which converts the distillate of vacuum distillation units. Newer processes, such as hydrocrackers, are used to produce light products from the heavy bottom products. Finally, all outputs may be treated to upgrade the product quality (e.g., sulfur removal using a hydrotreater). Side processes that are used to condition inputs and/or produce hydrogen or by-products include crude conditioning (e.g., desalting), hydrogen production, power and steam production, and asphalt production. Lubricants and other specialized products may be produced at select locations.

The principal energy consuming processes in refineries, in order of overall energy consumption in the United States, are the crude (or atmospheric) distillation and vacuum distillation units, hydrotreaters, reformer, alkylate production, catalytic crackers and hydrocrackers.

Figure 6 provides a simplified flow diagram for a refinery. The main production steps in refineries are discussed below, providing a brief process description and the most important operation parameters, such as energy use (see Chapter 4). These descriptions follow the flow diagram, from the initial intake of crude through final production. The flow of intermediates between the processes will vary by refinery, and depends on the structure of the refinery, the type of crude processes used, and the product mix.

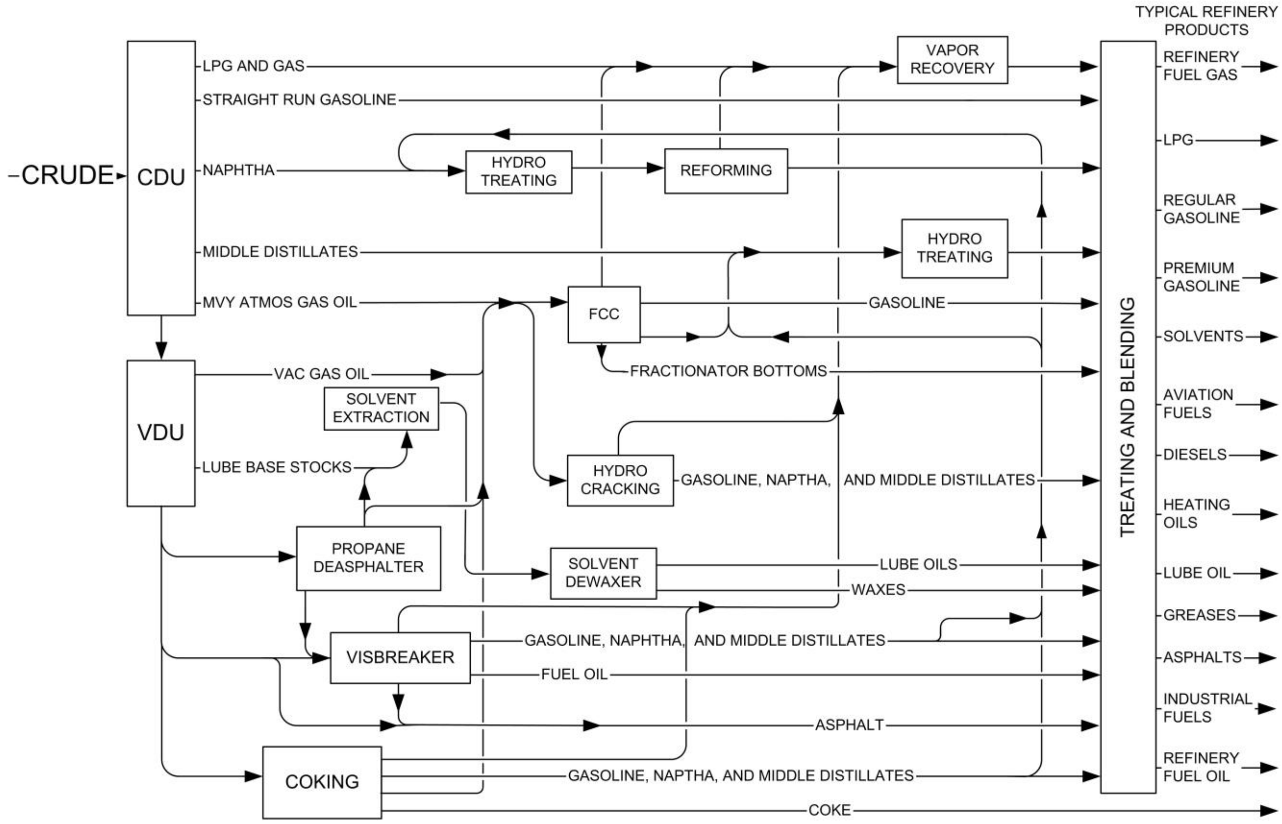

Figure 6. Simplified flowchart of refining processes and product flows. ***Minor processes are not depicted. Flowchart may not apply to an individual refinery. Adapted from Gary et al. (2007).***

Desalting. If the salt content of the crude oil is higher than 10 lb/1000 barrels of oil, the crude requires desalting (Gary et al., 2007). Desalting will reduce corrosion and minimize fouling of process units and heat exchangers. Heavier crudes generally contain more salts, making desalting more important in current and future refineries. The salt is washed from the crude with water (3-10% at temperatures of 200-300°F (90-150ºC)). The salts are then dissolved in the water and an electric current is used to separate the water from the oil. This process also removes suspended solids. Desalting can help to minimize fouling downstream, thereby reducing energy costs. The different desalting processes vary in the amount of water used and the electric field used for separation of the oil and water. The efficiency of desalting is influenced by the pH, gravity, viscosity, and salt content of the crude oil, and by the volume of water used in the process. Electricity consumption from desalting varies between 0.01 and 0.02 kWh/barrel of crude oil (IPPC, 2002).

Crude Distillation Unit (CDU). In all refineries, desalted and pretreated crude oil is split into three main fractions through a fractional distillation process according to its boiling range. The crude oil is heated in a furnace to approximately 750°F (390ºC), and subsequently fed into the fractionating or distillation tower. Most CDUs have a two-stage heating process. First the hot gas streams of the reflux and product streams are used to heat the desalted crude to about 550°F (290ºC). Second, it is further heated in a gas-fired furnace to about 750ºF (Gary et al., 2007). The feed is fed into the distillation tower at a temperature between 650 and 750°F (340-390ºC). Energy efficiency of the heating process can be improved by using pump-around reflux to increase heat transfer (at higher temperatures at lower points in the column).

In the tower, the different products are separated based on their boiling points. The boiling point is a good measure for the molecule weight (or length of the carbon chain) of the different products. Distillation towers contain between 30 and 50 fractionation trays, depending on the desired purity and number of product streams produced at a given CDU.

The lightest fraction includes fuel gas, LPG and gasoline. The overhead, which is the top or lightest fraction of the CDU, is a gaseous stream and is used as fuel or for blending.

The middle fraction includes kerosene, naphtha, and diesel oil. The middle fractions are used for the production of gasoline and kerosene. The naphtha is transferred to the catalytic reformer or used as feedstock for the petrochemical industry.

The heaviest fraction is fuel oil, which has the lowest economic value of the crude oil products. Fuel oil can be further processed in a conversion unit to produce more valuable products. Dependent on the crude oil, approximately 40% of the products of the CDU (on energy basis) cannot be used directly and are fed into the vacuum distillation unit (VDU), where distillation is performed under low pressure.

Because the CDU processes all incoming crude oil, it consumes a large gross quantity of energy, although when compared with the conversion process this energy demand is relatively low. Energy efficiency opportunities include improved heat recovery and heat exchange (process integration) and improved separation efficiencies. Integration of heat from the CDU and other parts of the refinery may lead to additional energy savings.

Vacuum Distillation Unit (VDU) or High Vacuum Unit (HVU). The VDU/HVU further distills the heaviest fraction (e.g., heavy fuel oil) from the CDU under vacuum conditions. The reduced pressure decreases the boiling points, making further separation of the heavier fractions possible while reducing undesirable thermal cracking reactions and associated fouling. Low pressure technologies require much larger process equipment. In the VDU, the incoming feedstream is heated in a furnace to 730-850°F (390-450ºC).

Vacuum conditions are maintained by the use of steam ejectors, vacuum pumps, and condensers. It is essential to obtain a very low pressure drop over the distillation column to reduce operating costs.

Of the VDU products, the lightest fraction becomes diesel oil. The middle fraction, which is light fuel oil, is sent to the hydrocracker (HCU) or fluid catalytic cracker (FCC), and the heavy fuel oil may be sent to the thermal cracker (if present at the refinery).

The distillation products are further processed, depending on the desired product mix. Refinery gas is used as fuel in the refinery operations to generate heat (furnaces), steam (boilers) or power (gas turbines). Refinery gas may also be used to blend with LPG, for hydrogen production, or may be flared. Hydrogen is used in different processes in the refinery to remove sulfur (e.g., hydrotreating) and to convert to lighter products (e.g., hydrocracking).

Hydrotreater. Naphtha is desulfurized in the hydrotreater and processed in a catalytic reformer. Contaminants such as sulfur and nitrogen are removed from gasoline and lighter fractions by hydrogen over a hot catalyst bed. Sulfur removal is necessary to avoid catalyst poisoning downstream, and to produce a clean product. The treated light gasoline is sent to the isomerization unit and the treated naphtha to the catalytic reformer or platformer to have its octane level increased. Hydrotreaters are also used to desulfurize other product streams in the refinery.

Although many different hydrotreater designs are marketed, they all work along the same principle. The feedstream is mixed with hydrogen and heated to a temperature between 500 and 800°F (260-430ºC). In some designs the feedstream is heated and then mixed with the hydrogen. The reaction temperature should not exceed 800°F (430ºC) to minimize cracking. The gas mixture is led over a catalyst bed of metal oxides (most often cobalt or molybdenum oxides on different metal carriers). The catalysts help the hydrogen to react with sulfur and nitrogen to form hydrogen sulfides (H_2S) and ammonia. The reactor effluent is then cooled, and the oil feed and gas mixture is then separated in a stripper column. Part of the stripped gas may be recycled to the reactor.

In the hydrotreater, energy is used to heat the feedstream and power to transport the flows. The hydrotreater also has a significant indirect energy use because of the consumption of hydrogen. In the refinery most hydrogen is produced through reforming (see below) and some as a by-product of cracking.

Catalytic Reformer. The reformer is used to increase the octane level in gasoline. The desulfurized naphtha and gasoline streams are sent to the catalytic reformer. The product, called reformate, is used in blending of different refinery products. The catalytic reformer processes between 30 and 40% of all the gasoline produced in the United States. Because the catalytic reformer uses platinum as catalyst, the feed needs to be desulfurized to reduce the danger of catalyst poisoning. New catalysts are currently entering the market having higher activity, robustness, and tolerance of feedstock contaminants. Increasing the tolerance of catalysts to contaminants (e.g., sulfur and water) reduces the need for pretreatment of feedstock (U.S. DOE-OIT, 2007).

Reforming is undertaken by passing the hot feed stream through a catalytic reactor. In the reactor, various reactions, such as dehydrogenation, isomerization and hydrocracking occur to reformulate the chemical formulas of the stream. Some of the reactions are endothermic and others exothermic. The types of reactions depend on the temperature, pressure and velocity in the reactor. Undesirable side-reactions may occur and need to be limited. Hydrogen is a valuable by-product of the catalytic reforming process that is used elsewhere in the refinery, but is often insufficient to meet a refinery's total hydrogen requirement.

Various suppliers and developers market a number of reforming processes. In principle all designs are continuous, cyclic or semi-regenerative, depending on the frequency of catalyst regeneration (Gary et al., 2007). In the continuous process, the catalysts can be replaced during normal operation, and regenerated in a separate reactor. In the semi-regenerative reactor, the reactor needs to be stopped for regeneration of the catalysts. Depending on the severity and operating conditions, the period between regenerations is between 3 and 24 months (Gary et al., 2007). The cyclic process is an alternative in between these two processes. The advantage of the semi-regenerative process is the low capital cost. The marketed processes vary in reactor design.

Fluid Catalytic Cracker (FCC). The fuel oil from the CDU is converted into lighter products over a hot catalyst bed in the fluid catalytic cracker (FCC). The FCC is the most widely used conversion process in refineries. The FCC produces gasoline, diesel and fuel oil. The FCC is mostly used to convert heavy fuel oils into gasoline and lighter products. The FCC has virtually replaced all thermal crackers.

In a fluidized bed reactor filled with particles carrying the hot catalyst and a preheated feed (500-800°F, 260-425ºC), at a temperature of 900-1000°F (480-540ºC) the feed is 'cracked' to molecules with smaller chains. Different cracking products are generated, depending on the feed and conditions. During the process, coke is deposited on the catalysts. The used catalyst is continuously regenerated for reuse by burning off the coke to either a mixture of carbon monoxide (CO) and carbon dioxide (CO_2), or completely to CO_2. If burned off to a CO/CO_2-mixture, the CO is combusted to CO_2 in a separate CO-burning waste heat recovery boiler to produce steam. The regeneration process is easier to control if the coke is burned directly to CO_2, but a waste heat recovery boiler should be installed to recover the excess heat in the regenerator. The cracking reactions are endothermic and the regeneration reactions exothermic, providing an opportunity for thermal integration of these two processes.

Older FCCs used metal catalysts, while new FCC designs use zeolite catalysts that are more active. This has led to a re-design of modern FCC units with a smaller reactor, and most of the reactions taking place in the so-called riser, which leads the hot feed and regenerated catalysts to the reaction vessel. The different FCC designs on the market vary in the way that the reactor and regeneration vessels are integrated. Altering the catalyst circulation rate controls the process.

Fluid catalytic crackers are net energy users, due to the energy needed to preheat the feed stream. However, modern FCC designs also produce steam and power (if power recovery turbines are installed) as by-products. The power recovery turbines can also be used to compress the air for the cracker. The recovery turbine is installed prior to the CO or waste heat boiler, if the FCC works at pressures higher than 15 psig (Gary et al., 2007).

Hydrocracker (HCU). The hydrocracker has become an important process in the modern refinery to allow for flexibility in product mix. The hydrocracker provides a better balance of gasoline and distillates, improves gasoline yield, octane quality, and can supplement the FCC to upgrade heavy feedstocks (Gary et al., 2007). In the hydrocracker, light fuel oil is converted into lighter products under a high hydrogen pressure and over a hot catalyst bed. The main products are naphtha, jet fuel and diesel oil. It may also be used to convert other heavy fuel stocks to lighter products. The hydrocracker concept was developed before World War II to produce gasoline from lignite in Germany, and was further developed in the early 1960s. Today hydrocrackers can be found in many modern large refineries around the world.

In the hydrocracker, many reactions take place. The principal reactions are similar to that of a FCC, although *with* hydrogenation. The reactions are carried out at a temperature of 500-750°F (290-400ºC) and increased pressures of 8.3 to 13.8 Bar. The temperature and pressures used may differ with the licensed technology. The reactions are catalyzed by a combination of rare earth metals. Because the catalyst is susceptible to poisoning, the hydrocracker feed needs to be prepared by removing metallic salts, oxygen, nitrogenous compounds and sulfur. This is done by first hydrogenating the feed, which also saturates the olefins. This is an exothermic reaction, but insufficient to provide all the heat for the hydrotreating units of the cracker. The nitrogen and sulfur-compounds are removed in a stripper column, while water is removed by a molecular sieve dryer or silica gel.

The prepared feed is mixed with recycled feed and hydrogen, and preheated before going to the reactor. The reactions are controlled by the temperature, reactor pressure, and velocity. Typically the reactor is operated with a conversion efficiency of 40 to 50%, meaning that 40 to 50% of the reactor product has a boiling point below 400F (205ºC). The product flow (effluent) is passed through heat exchangers and a separator, where hydrogen is recovered for recycling. The liquid products of the separator are distilled to separate the C_4 and lighter gases from the naphtha, jet fuel and diesel. The bottom stream of the fractionator is mixed with hydrogen and sent to a second-stage reactor to increase the conversion efficiency to 50-70% (Gary et al., 2007).

Various designs have been developed and are marketed by a number of licensors in the United States and Western Europe. The hydrocracker consumes energy in the form of fuel, steam and electricity (for compressors and pumps). The hydrocracker also consumes energy indirectly in the form of hydrogen. The hydrogen consumption is between 150 and 300 scf/barrel of feed (27-54 Nm^3/bbl) for hydrotreating and 1000 and 3000 scf /barrel of feed (180-540 Nm^3/bbl) for the total plant (Gary et al., 2007). The hydrogen is produced as by-product of the catalytic reformer, and in dedicated steam reforming plants (see below).

Coking. A new generation of coking processes has added additional flexibility to the refinery by converting the heavy bottom feed into lighter feedstocks and coke. Coking can be described as a severe thermal cracking process. The modern coking processes can also be used to prepare a feed for the hydrocracker (see above).

Delayed coking is currently one of the preferred choices for upgrading the heavy bottom feed. This is due to the flexibility of the process to handle any type of residue. Delayed coking is a semi-batch process, using two coke drums, a fractionation tower, and a coking furnace. A typical coking cycle in a delayed coking unit includes 16 to 24 hours online and 16 to 24 hours cooling and decoking (U.S EPA, 2010, Gary et al., 2007). It provides complete rejection of metals and carbon, and partially converts to liquid products such as naphtha and diesel. A main disadvantage of the process is the high coke formation and low yields of liquid products (Rana et al., 2007).

In the FLEXICOKING® process (developed by ExxonMobil), a heavy feed is preheated between 600 and 700°F (315 to 370ºC) and sprayed on a bed of hot fluidized coke (recycled internally). The coke bed has a reaction temperature between 950 and 1000°F (510 to 540ºC), at which cracking reactions take place. Cracked vapor products are separated in cyclones and are quenched. Some of the products are condensed, while the vapors are led to a fractionator column, which separate various product streams. The coke is stripped from other products, and then processed in a second fluidized bed reactor where it is heated to 1100°F (590ºC). The hot coke is then gasified in a third reactor in the presence of steam and air to produce synthesis gas. Sulfur (in the form of H_2S) is removed, and the synthesis gas (mainly consisting of CO, H_2, CO_2 and N_2) can be used as fuel in (adapted) boilers or furnaces. The coking unit is a consumer of fuel (in preheating), steam and power.

Fluid coking is a simplified version of FLEXICOKING® through a continuous coking process that produces a higher grade of petroleum coke than delayed coking units. This process, however, consumes 15% to 25% of the coke produced to provide for the process heat requirements eliminating the need for external fuel use, but resulting in substantial greenhouse gas emissions. Fluid coking technology is not widely used in the United States, with only three units currently in operation (Gary et al., 2007; U.S. DOE-OIT, 2007; U.S. EPA, 2010).

Visbreaker. Visbreaking is a relatively mild thermal cracking operation, used to reduce the viscosity of the bottom products to produce fuel oil. This reduces the production of heavy fuel oils, while the products can be used to increase FCC feedstock and increase gasoline yields. This is accomplished by cracking the side chains of paraffin and aromatics in the feed, and cracking of resins to light hydrocarbons. Depending on the severity (i.e., time and temperature in the cracker) of the reactions, different products may be produced.

Visbreaking consists of two main processes: coil (or furnace) cracking and soak cracking. Coil cracking uses higher reactor temperatures and shorter residence times, while soak cracking has slightly lower temperatures and longer residence times (Gary et al., 2007). The reaction products are similar, but the soaker cracker uses less energy due to its lower temperature, and has longer run times resulting from reduced coke deposition on the furnace tubes. A soaker furnace consumes about 15% less energy than a coil furnace. The visbreaker consumes fuel (to heat the feed), steam and electricity.

Alkylation and Polymerization. Alkylation (the reverse of cracking) is used to produce alkylates (used in higher octane motor fuels), as well as butane liquids, LPG, and a tar-like by-product. Several designs may be used, with hydrofluoric acid or sulfuric acid catalyzing the process. The most suitable alkylation process for a given refinery is determined by economics, especially with regard to the costs of acid purchase and disposal (Gary et al., 2007). Alkylation processes use steam and power. There are no large differences in energy intensity between both processes (Gary et al., 2007).

Hydrogen Manufacturing Unit or Steam Reforming (HMU). There are a number of supporting processes that do not produce the main refinery products directly, but produce intermediates used in the various refining processes. Hydrogen is generated from natural gas and steam over a hot catalyst bed, similar to the processes used to make hydrogen for ammonia.

Hydrogen is produced by reforming the natural gas feedstock with steam over a catalyst, producing synthesis gas. Synthesis gas contains a mixture of carbon monoxide and hydrogen. The carbon monoxide is then reacted with steam in the water-gas-shift reaction to produce carbon dioxide (CO_2)

and hydrogen. The CO_2 is then removed from the main gas stream using absorption, producing hydrogen.

Energy is used in the form of fuel (to heat the reformer), steam (in the steam methane reforming), and power (for compression). Many different licensors supply the technology. Modern variants use a physical adsorption process to remove CO_2, requiring less energy than chemical absorption processes.

Gas Processing Unit. Refinery gas processing units are used to recover C_3, C_4, C_5 and C_6 components from the different processes, and to produce a desulfurized gas that can be used as fuel or for hydrogen production in steam reforming (see above). The lighter products are used as fuel or for hydrogen production, while the heavier fraction is recycled in the refinery. Recovering the C3+ fraction for further processing, instead of using it as fuel, can result in costs savings, if replaced by low cost natural gas to use as fuel instead.

The process consists of a number of distillation, absorption and stripper columns to recover the ethane, propane and butane. The process uses fuel (to heat the incoming gas) and power (for compressors and other uses).

Acid Gas Removal. Acid gases such as H_2S and CO_2 need to be removed to reduce air pollution (before 1970 they were burned off) and are produced as a by-product of creating higher quality refinery products. These gases are removed by an (chemical) absorption process, and then further processed. H_2S can be processed into elemental sulfur through the Claus process, which consumes fuel and electricity and produces low-pressure steam (1.7 bar).

Bitumen Blower Unit (BBU). Heavy fuel oil of some heavy crude oil is blown with hot air to produce bitumen or asphalt.

Other processes may be used in refineries to produce lubricants (lube oil), petrochemical feedstock and other specialty products. These processes consist mainly of blending, stripping and separation processes. Although these processes are quite energy-intensive, this Guide does not discuss them in detail, as they are not found in a large number of refineries.

Table 2 and Figure 7 provide an overview of the processing capacities of the different processes used in U.S. refineries, based on the capacity per January 1st, 2012. The distribution of the processes will vary by state depending on the type of crudes used and products produced. For example, California has a much higher capacity (relative to CDU-capacity) of hydrocracking and hydrotreating, when compared to the U.S. average. This is due to the types of crude processed in California, the relative higher desired output of lighter products (e.g., gasoline), and the regulatory demand for lower sulfur-content from gasoline to reduce air pollution from transport.

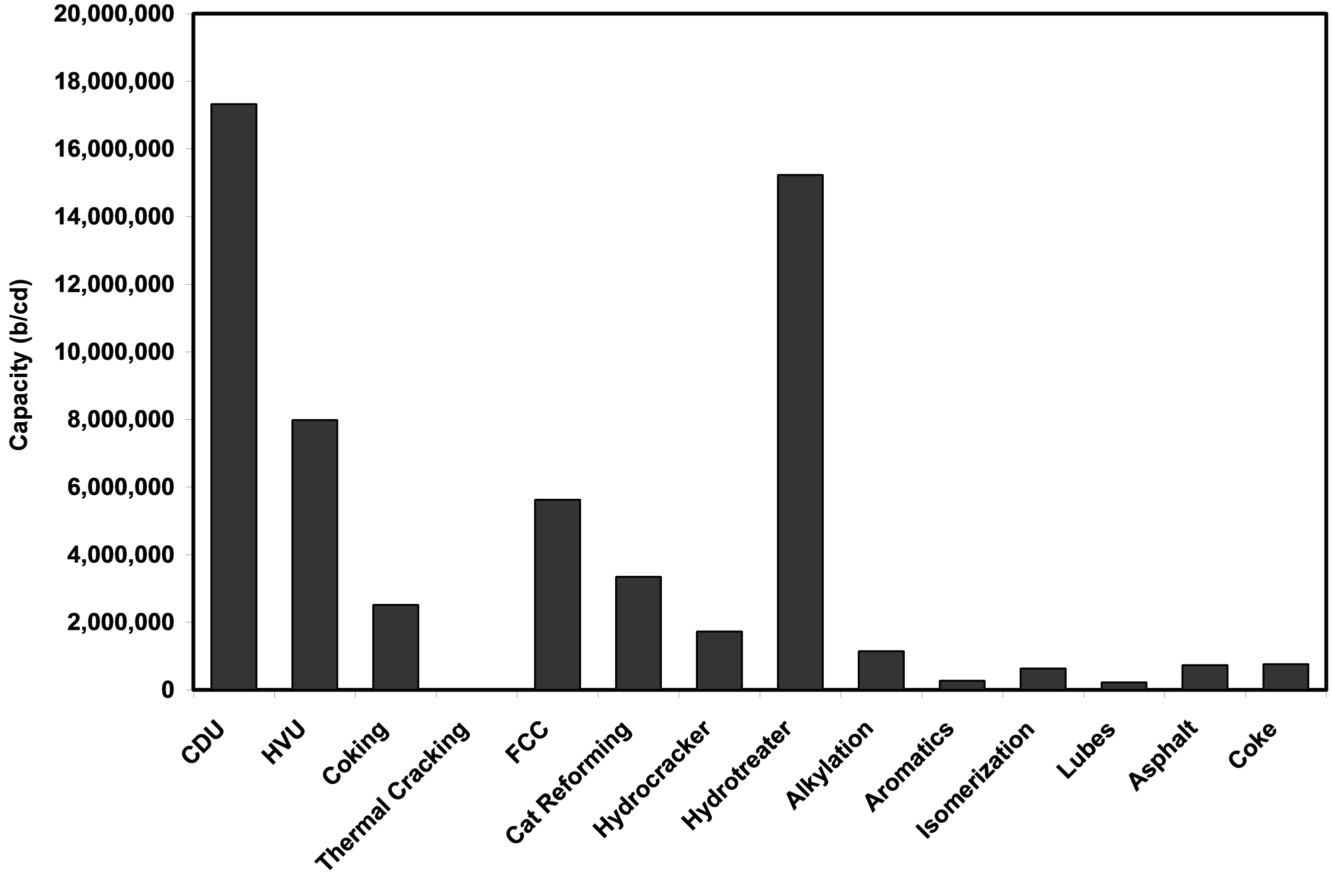

Figure 7. Capacity distribution of the major refining processes in U.S. petroleum refineries, as of January 1st, 2012. ***Source: Energy Information Administration.***

Table 2. Capacity distribution of the major refining processes in U.S. petroleum refineries, as of January 1st, 2012. The distribution is also given as share of CDU capacity. ***Source: Energy Information Administration.***

Process	**Capacity (barrel per calendar day)**	**Distribution (share of CDU capacity)**
Crude Distillation	17,322,178	100.0%
Vacuum Distillation	7,978,138	46.1%
Coking	2,515,566	14.5%
Thermal Operations	24,450	0.1%
Catalytic Cracking	5,622,982	32.5%
Catalytic Reforming	3,347,475	19.3%
Hydrocracking	1,727,687	10.0%
Hydrotreating	15,226,426	87.9%
Alkylation	1,146,100	6.6%
Aromatics	272,914	1.6%
Isomerization	632,266	3.7%
Lubes	222,754	1.3%
Asphalt	731,378	4.2%
Coke	756,566	4.4%
Hydrogen	3,215 MMcfd	-
Sulfur	36,663 tpd	-

4. Energy Consumption

The petroleum refining industry is one of the largest energy consuming industries in the United States. Energy use in refineries varies over time due to changes in the type of crude processed, the product mix and complexity of refineries, as well as the sulfur content of the final products. Furthermore, operational factors such as capacity utilization, maintenance practices, and equipment age affect energy use from year to year.

The petroleum refining industry spent almost $9 billion on energy purchases in 2010. Significantly reduced natural gas prices in 2012/2013 may have reduced these costs in 2013. Figure 8 depicts trends in the energy expenditures of the petroleum refining industry. The graph shows a steady increase in total expenditures for purchased electricity and fuels up to 2008. In 2009, the total energy expenditures dropped to 60% of the 2008 expenditures, which resulted from the drop in demand caused by the economic recession. The energy expenditure as share of value added decreased from about 20% in the early 2000's to about 10% in 2010.

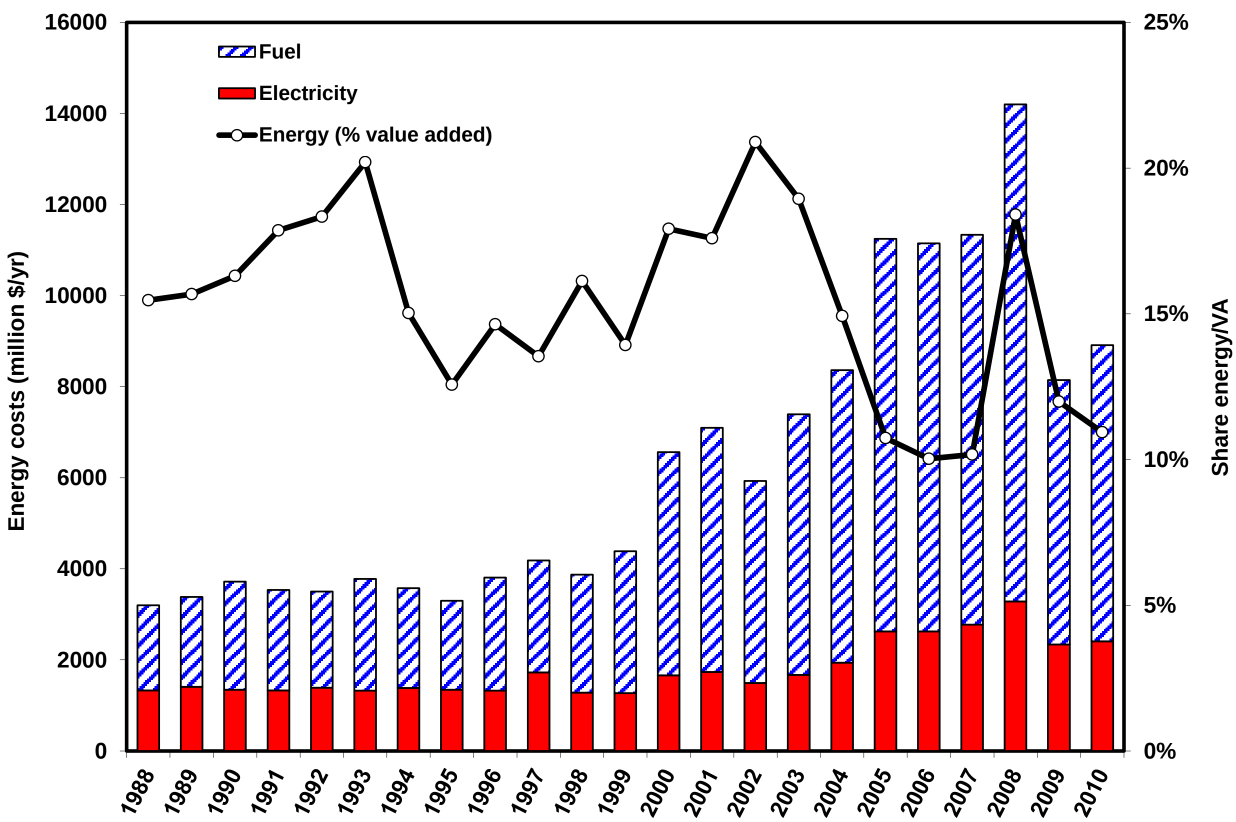

Figure 8. Annual energy costs of petroleum refineries in the United States 1988-2010 for purchased fuels and electricity. ***This excludes the value of fuels (i.e., refinery gas and coke) and electricity generated in the refinery. The total purchased energy costs are given as share of the value added produced by petroleum refineries. Source: U.S. Census, Annual Survey of Manufacturers.***

Energy consumption in refineries peaked in 1998 and has slightly declined since then. Based on data published by the Energy Information Administration, energy consumption trends are estimated by purchased fuel since 1995.[2] In 2011, the latest year for which data is currently available, total final energy consumption is estimated at 3,138 TBtu. Primary energy consumption[3] is estimated at 3,512 TBtu. The difference between primary and final energy consumption is relatively small due to the limited proportion of electricity consumption within the refinery, and the relatively large amount of self-produced electricity. Figure 9 depicts the annual energy consumption, by fuel type, of petroleum refineries between 1995 and 2011.

[2] Data before 1995 are also available. However, for some years (including 1995 and 1997) the data reported by EIA is not complete, and interpolations were made by the authors to estimate total energy consumption. For example, for 1995 EIA did not report on consumption of natural gas, coal, purchased electricity and purchased steam, while for 1997 it did not report on coal, purchased steam and other fuels. Furthermore, we use electricity purchase data as reported by the EIA, although the U.S. Census reports slightly different electricity purchases for most years. The differences are generally small and do not affect overall energy use data.

[3] Final energy assigns only the direct energy content to secondary energy carriers like purchased electricity and steam to calculate energy consumption. Primary energy consumption includes the losses of offsite electricity and steam production. We assume an average efficiency of power generation on the public grid of 32%. Steam generation efficiency is supposed to be similar to that of refinery boilers (assumed at 77%).

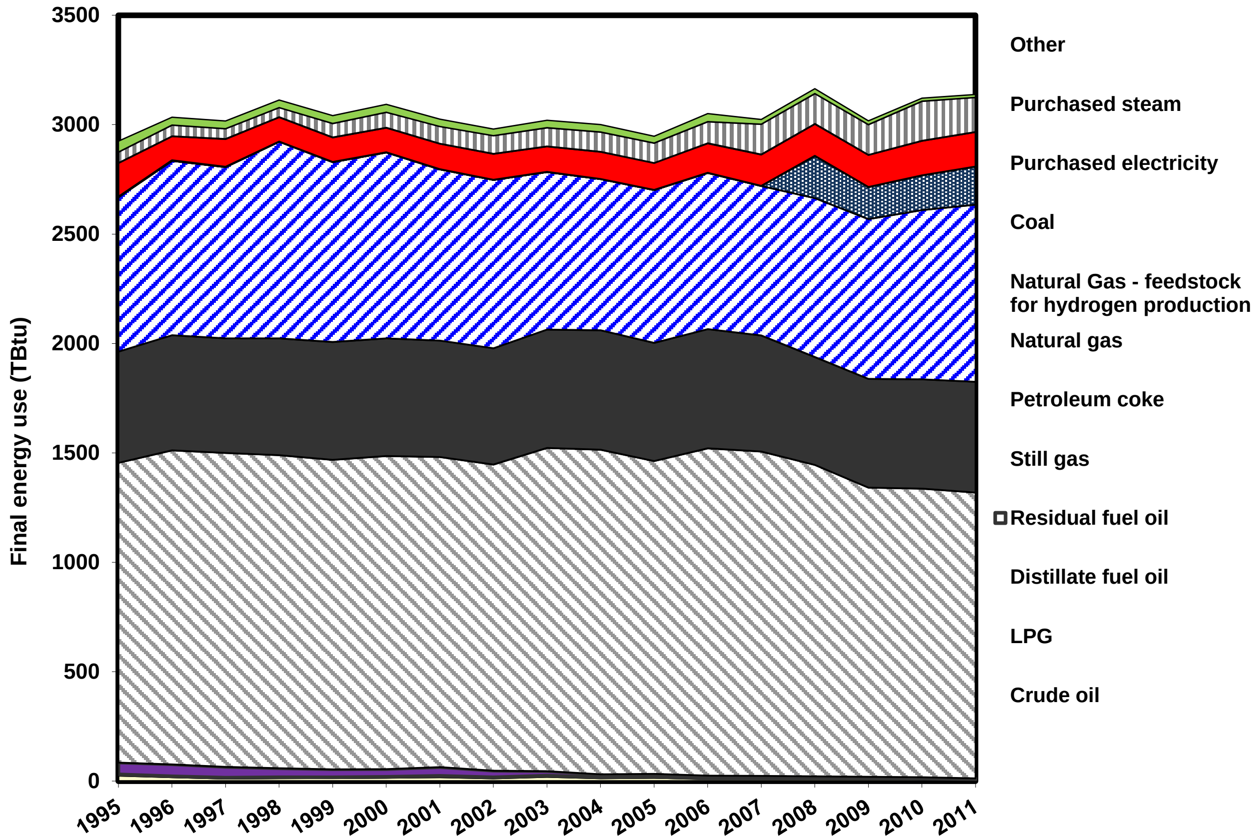

Figure 9. Annual final energy consumption of U.S. petroleum refineries for the period 1995–2011. ***Data for 1995 and 1997 contains estimated values for natural gas, coal, electricity and steam purchases. Natural gas that is used as feedstock for hydrogen production is separately reported since 2008. The order in the legend corresponds with the order of fuels in the graph. Source: Petroleum Supply Annual, Energy Information Administration.***

Energy use has remained relatively flat since 1995, while production volumes and product mixes have changed, demonstrating an improvement of the energy efficiency of the industry over the same period. This figure also shows that the main fuels used in the refinery are refinery gas (i.e., still gas), natural gas and coke. Refinery gas and coke are by-products of the different processes. Coke is mainly produced in the crackers, while the refinery gas comprises the lightest fraction from the distillation and cracking processes. Natural gas, electricity, and steam represent the largest proportions of purchased fuels in the refineries. Natural gas is used for the production of hydrogen, fuel for co-generation of heat and power (CHP), and as supplementary fuel in furnaces. Electricity is mainly used to power pumps, compressors, and other auxiliary equipment. Some electricity may be used in the electrostatic precipitators in the desalting process.

Petroleum refineries are one of the largest cogenerators in the country, after the pulp and paper and chemical industries. In 2006, cogeneration within the refining industry represented almost 14% of all industrial cogenerated electricity (EIA, 2009). In the petroleum refining industry, cogeneration peaked at almost 35% of total electricity use in 1999, but stabilized from 2005 onwards at about 28%. In 2010, the petroleum refining industry generated approximately 18 TWh, representing almost 29% of all power consumed onsite by refineries (U.S. Census, 2011). Figure

10 shows the historic development of electricity generation and purchases in oil refineries (generation data for the years 2000, 2002, and 2003 were not reported by the U.S. Census).

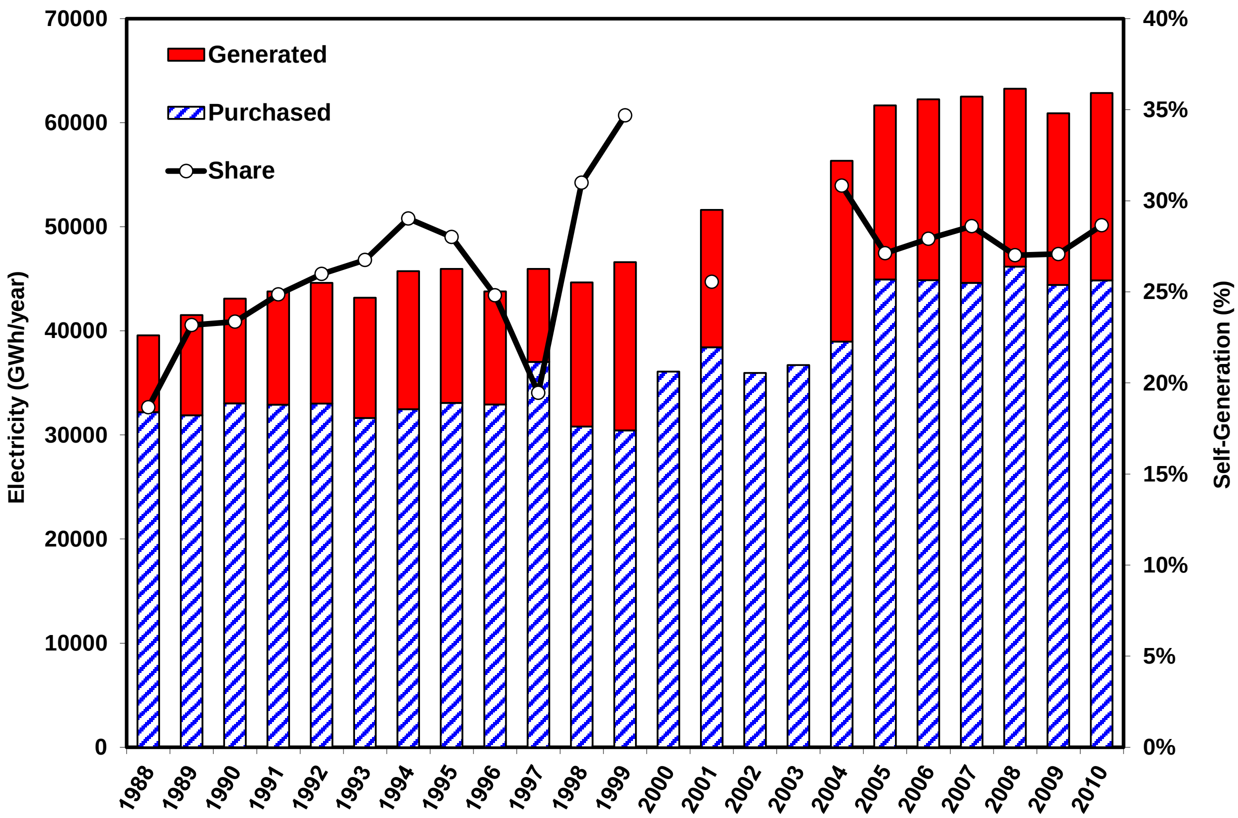

Figure 10. Electricity purchases and generation by petroleum refineries from 1988 to 2010. On the right-hand axis the share of self-generation is expressed as function of total power consumption. ***Source: U.S. Census, Annual Survey of Manufacturers.***

In a typical refinery, key energy consuming processes include crude distillation, hydrotreating, reforming, vacuum distillation, and catalytic cracking. Hydrocracking and hydrogen production comprise a rising proportion of total energy consumption in the refining industry. A 2011 energy balance for refineries has been developed based on publicly available data on process throughput (EIA, 2012), specific energy consumption (Gary et al., 2007; U.S. DOE-OIT, 1998b, U.S. DOE-OIT, 2007), and energy consumption data (EIA, 2012). Table 3 provides the estimated energy balance for 2011. The energy balance is an estimate based on publicly available data, and is based on assumptions for process efficiencies and throughputs. The estimated energy balance matches with available energy consumption data for almost 100% on a final energy basis, and for more than 98% on a primary energy basis. The process energy uses should be regarded as approximate values, providing a framework for understanding key energy consuming processes in refineries.

Table 3. Estimated 2011 energy balance for the U.S. petroleum refining industry. ***Estimates are based on a combination of publicly available data sources. The energy balance for an individual refinery will be different due to different process configurations. Data sources are given in the text.***

Process	Throughput	Fuel	Steam	Electricity	Final	Primary
	Million bbl/year [1]	TBtu	TBtu	GWh	TBtu [2]	TBtu [3]
Desalter	5,462.7	0.2	0.0	273.1	1.1	3.1
CDU	5,462.7	369.3	230.4	3,714.7	681.2	708.1
VDU	2,507.5	119.9	130.4	877.6	292.3	298.6
Thermal Cracking	774.6	90.0	-11.2	4,802.8	91.8	126.7
FCC	1,830.6	105.1	0.5	6,810.0	129.0	178.4
Hydrocracker	537.9	72.7	39.2	6,024.3	144.1	187.8
Reforming	1,078.5	190.7	93.7	3,160.0	323.2	346.1
Hydrotreater	4,835.9	332.7	354.9	20,310.8	862.9	1,010.2
Deasphalting	110.9	15.9	0.3	210.8	17.0	18.5
Alkylates	365.9	13.0	120.8	2,634.8	178.9	198.0
Aromatics	86.2	10.3	3.6	258.5	15.9	17.8
Asphalt	240.0	50.2	0.0	624.0	52.3	56.9
Isomers	203.8	90.1	39.8	397.4	143.2	146.0
Lubes	70.4	90.9	2.6	1,295.2	98.7	108.1
Hydrogen	5,083.2	228.7	0.0	762.5	231.3	236.9
Sulfur	11.2	0.0	-100.5	134.3	-130.0	-129.1
Total Process Site Use		**1,780**	**905**	**52,291**	**3,133**	**3,512**
Purchases			158.3	46195		
Site Generation			746.3			
Cogeneration [4]		65.0	28.6	6096		
Boiler generation [5]			717.7			
Boiler fuels		932.1				
Total Energy Consumption		**2,777**	**158**	**46,195**	**3,093**	**3,475**

Notes:

1. Units are million barrels/year, except for hydrogen (million lbs/year) and sulfur (million short tons/year).
2. Final fuel use is calculated by estimating the boiler fuel to generate steam used. Electricity is accounted as site electricity at 3412 Btu/kWh.
3. Primary fuel use includes the boiler fuel use and primary fuels used to generate electricity. Including transmission and distribution losses, the electric efficiency of the public grid is equal to 32%, accounting electricity as 10,660 Btu/kWh. Some refineries operate combined cycles with higher efficiencies. For comparison, Solomon accounts electricity at 9,090 Btu/kWh.
4. Cogeneration is assumed to be in large singe-cycle gas turbines with an electric efficiency of 32%.
5. Boiler efficiency is estimated at 77%.

Figure 11 summarizes the results of Table 3, depicting the primary energy consumption of the different processes.

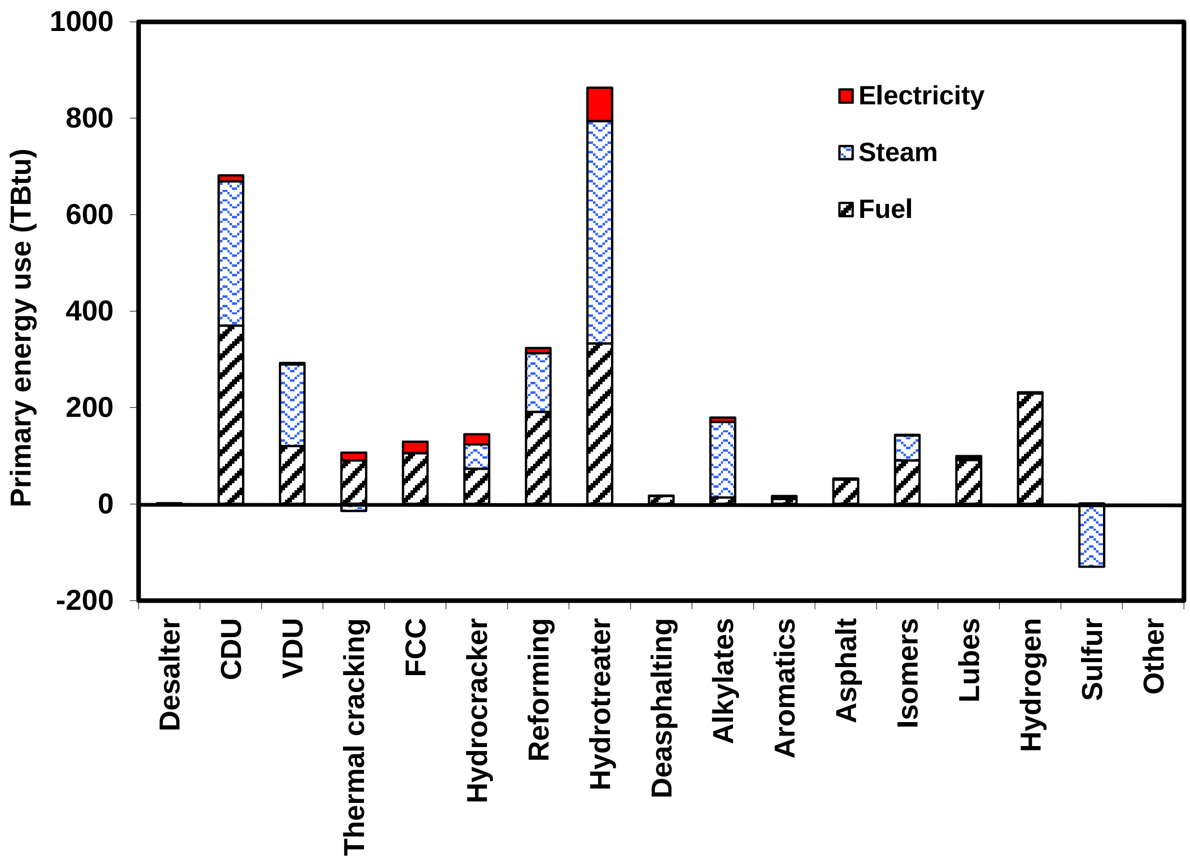

Figure 11. Estimated energy use by petroleum refining process. ***Energy use is expressed as primary energy consumption. Electricity is converted to fuel using 10,660 Btu/kWh (equivalent to an***

efficiency of 32% including transmission and distribution losses). All steam is generated in boilers with an efficiency of 77%.

The largest energy consuming processes are hydrotreating and crude distillation, followed by catalytic reforming, vacuum distillation, and the steam reforming unit. A number of processes consume a comparable quantity of energy, including thermal cracking, catalytic cracking, hydrocracking, alkylate and isomer production.

Note that the figures in Table 3 and Figure 11 are based on publicly available data. All installed processes are assumed to have similar capacity utilization, based on the average national capacity utilization. In reality the load of different processes may vary, leading to a somewhat different distribution. The severity of cracking and the specific treated feed in hydrotreating may also impact energy use. An average severity is assumed for both of these factors. Furthermore, energy intensity assumptions are based on a variety of sources, and are balanced on the basis of available data. Different literature sources provide varying assumptions for these processes, especially with respect to electricity consumption.

Although the vast majority (85 to 90%) of greenhouse gas emissions in the petroleum fuel cycle occur during final consumption of the petroleum products, refineries remain a substantial source of greenhouse gas emissions due to their high energy consumption. This Guide focuses on CO_2 emissions resulting from the combustion of fossil fuels, although process emissions of methane and other greenhouse gases may occur at refineries. The estimates in this report are based on the fuel consumption as reported in the Petroleum Supply Annual of the Energy Information Administration, and emission factors determined by the Energy Information Administration and U.S. Environmental Protection Agency. Emission factors for electricity consumption are obtained from the Energy Information Administration (2013). The CO_2 emissions in 2011 are estimated at 231 million tonnes of CO_2 (equivalent to 62.9 MtCE). This is equivalent to about 16% of total industrial CO_2 emissions in the United States (U.S. EPA, 2012). Figure 12 provides estimates of CO_2 emissions (by fuel type) for several recent years. The figure shows that the main fuels contributing to the emission of CO_2 are still gas, natural gas and coke.

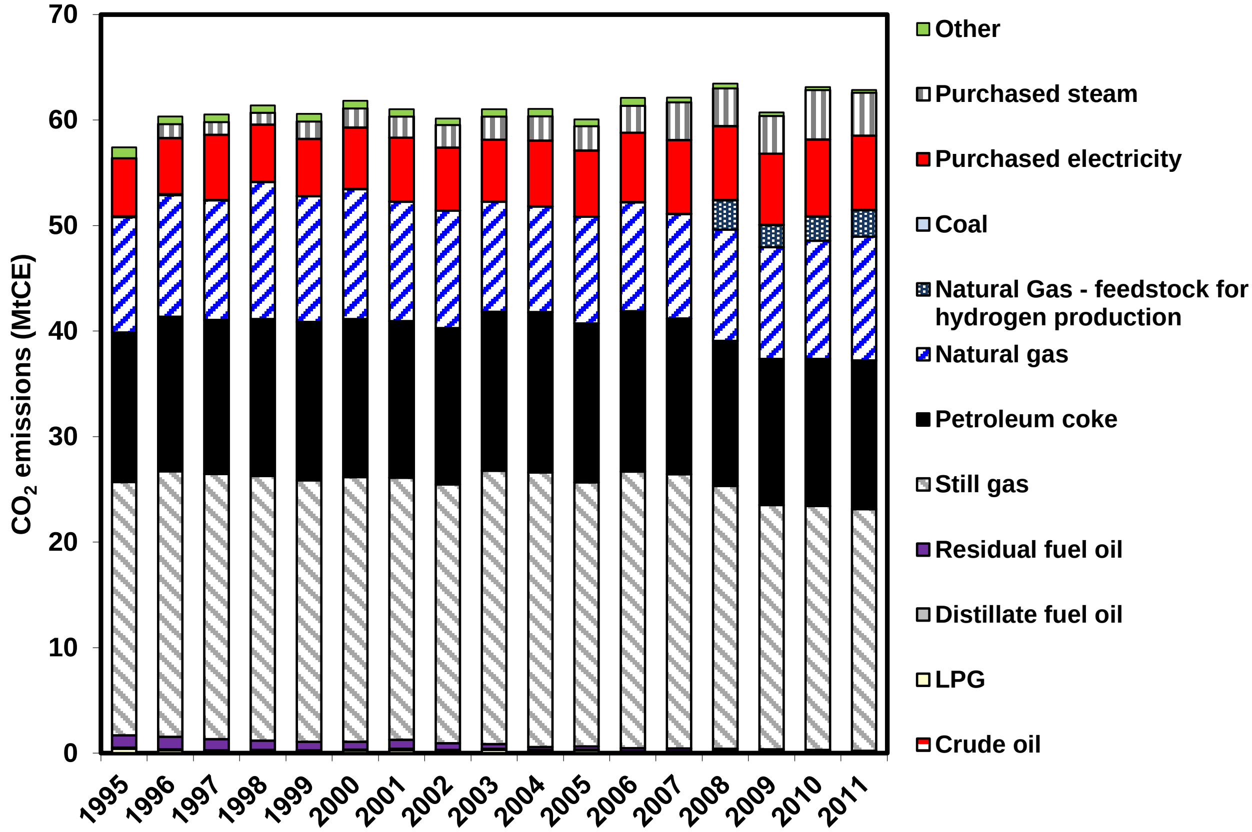

Figure 12. Estimated CO_2 emissions from fuel combustion and electricity consumption at U.S. petroleum refineries. ***Data for 1995 and 1997 include estimates for different fuels (i.e., coal, purchased steam, and other fuels). Natural gas that is used as feedstock for hydrogen production is separately reported since 2008. Sources: Energy Information Administration, U.S. Environmental Protection Agency.***

5. Energy Efficiency Opportunities

A wide variety of opportunities exist within petroleum refineries to reduce energy consumption, while maintaining or enhancing plant productivity, as evidenced by studies from several companies in the petroleum refining and petrochemical industries. Competitive benchmarking data indicate that most petroleum refineries can economically improve energy efficiency by 10% to 20%. For example, a 2002 assessment of energy use at the Equilon refinery (now Shell) at Martinez, California, found an overall efficiency improvement potential of 12% (U.S. DOE-OIT, 2002b). This savings potential amounts to annual cost reductions of millions to tens of millions of dollars for a refinery, depending on its current efficiency and size. Improved energy efficiency may further result in co-benefits that far outweigh the energy cost savings, and may lead to an absolute reduction in emissions.

Major areas for energy efficiency improvement include utilities (30%), fired heaters (20%), process optimization (15%), heat exchangers (15%), motor and motor applications (10%), and other areas (10%). Of these areas optimization of utilities, heat exchangers, and fired heaters offer the greatest low investment opportunities. While all projects incur operating costs and require engineering resources to develop and implement, the experiences of various oil companies have shown that most investments are relatively modest. Every refinery is unique, so the most favorable selection of energy efficiency opportunities should be made on a plant-specific basis.

In the following chapters, energy efficiency opportunities are classified based on technology area. In each technology area, technology opportunities and specific applications by process are discussed. Table 4 summarizes the energy efficiency measures described in this Guide, and provides access keys by process and utility system to the descriptions of the energy efficiency opportunities. This Guide is far from exhaustive. For example, the Global Energy Management System (GEMS) of ExxonMobil has developed 12 manuals containing some 1,200 pages describing in detail over 200 best practices and performance measures for key process units, major equipment, and utility systems. In addition to the strong focus on operation and maintenance of existing equipment, these practices also address energy efficiency in the design of new facilities. GEMS identified opportunities to improve energy efficiency by 15% at ExxonMobil refineries and chemical plants worldwide. This Guide provides a general overview of energy efficiency opportunities in an easily accessible format to help energy managers select areas for energy efficiency improvement.

This Guide includes case studies from U.S. refineries with specific energy and cost savings data, when available. For other measures, the Guide includes case study data from refineries around the world. The actual payback period and energy savings for individual refineries will vary, depending on plant configuration, size, location, and operating characteristics. Hence, the values presented in this Guide are offered as guidelines. Wherever possible, the Guide provides a range of estimated savings and payback periods under varying conditions.

In addition to technological improvements in equipment that conserve energy, changes in staff behavior and attitude can also have a significant impact. Staff should receive training in both applicable energy efficiency skills and in the company's general approach to energy efficiency in day-to-day practices. Personnel at all levels should be aware of energy use and objectives for energy efficiency improvement. Though isolated changes in staff behavior, such as switching off lights or improving operating guidelines, typically save only very small amounts of energy, they can have a substantial effect when performed consistently over long periods. Further details on these programs may be found in Chapter 6.

Participation in voluntary programs such as the ENERGY STAR program, or implementing an environmental management system (e.g., ISO 14001, or the new international standard for energy management ISO 50001), can help companies to track energy consumption and implement energy efficiency measures. One ENERGY STAR partner noted that combining the energy management programs with the ISO 14001 program has had the largest effect on saving energy of any efficiency measure enacted at their plants.

Table 4 provides an access key to the Guide. This table describes the applicable energy efficiency measures for each main refinery process. While boilers and lighting will be distributed around the refinery, they are exclusively designated as utilities.

Table 4. Matrix of energy efficiency opportunities in petroleum refineries. For each major process in the refinery (in rows) the applicable categories of energy efficiency measures are given (in columns). The numbers refer to the chapter or section describing energy efficiency.

Process	**Energy Management**	**Flare Gas Recovery**	**Power Recovery**	**Boilers**	**Steam Distribution**	**Heat Exchanger**	**Process Integration**	**Process Heaters**	**Distillation**	**Hydrogen Management**	**Motors**	**Pumps**	**Compressed Air**	**Fans**	**Lighting**	**Cogeneration**	**Power Generation**	**Other Opportunities**
Desalting	6											14						19
CDU	6	7.1			8.2	9.1	9.2	10	11		13	14		16				19
VDU	6				8.2	9.1	9.2	10	11					16				
Hydrotreater	6				8.2	9.1	9.2	10		12				16				19
Cat.Reformer	6	7.1			8.2	9.1	9.2	10		12				16				19
FCC	6	7.1	7.2		8.2	9.1	9.2	10						16				19
Hydrocracker	6	7.1	7.2		8.2	9.1	9.2	10		12				16				19
Coker	6	7.1			8.2	9.1	9.2	10						16				19
Visbreaker	6	7.1			8.2	9.1	9.2	10						16				
Alkylation	6				8.2	9.1	9.2	10						16				19
Light End	6				8.2	9.1	9.2											19
Aromatics	6				8.2	9.1	9.2	10										
Hydrogen	6				8.2	9.1	9.2	10		12				16				
Utilities	6	7.1	7.2	8.1	8.2	9.1	9.2			12			15	16	17	18	18	19

6. Energy Management and Control

A comprehensive approach to energy efficiency should be implemented in improving refinery performance. A strong, corporate-wide energy management program is essential to this process. Cross-cutting equipment and technologies such as boilers, compressors, and pumps are common to most plants and manufacturing industries, and present well-documented opportunities for improvement. The production process may also be fine-tuned to produce additional savings.

6.1 Energy Management Systems (EMS) and Programs

Changing how energy is managed by implementing an organization-wide energy management program is one of the most successful and cost-effective ways to bring about energy efficiency improvements.

An energy management program creates a foundation for improvement and provides guidance for managing energy throughout an organization. In companies without a clear program in place, opportunities for improvement may be unknown, or may not be promoted or implemented due to organizational barriers. These barriers may include a lack of communication among plants, a poor understanding of how to create support for an energy efficiency project, limited finances, poor accountability for performance metrics or changes from the status quo. Even though energy constitutes a significant cost for industry, companies may lack a strong commitment to improve energy management.

The U.S. EPA, through the ENERGY STAR program, has worked with many of the leading industrial manufacturers to identify the basic aspects of an effective energy management program.[4] The major elements in a strategic energy management program are depicted in Figure 13.

A successful program in energy management begins with a strong organizational commitment to continuous improvement of energy efficiency. This typically involves assigning oversight and management duties to an energy director, establishing an energy policy, and creating a cross-functional energy team (see Section 6.2). Steps and procedures are then put in place to assess performance through regular reviews of energy data, technical assessments, and benchmarking. From this assessment, an organization is then able to develop a performance baseline and set goals for improvement.

Performance goals help to shape the development and implementation of an action plan. An important aspect for ensuring the successes of the action plan is the involvement of personnel throughout the organization. Personnel at all levels should be aware of energy use and goals for efficiency. Staff should be trained in both skills and general approaches to energy efficiency in day-to-day practices. In addition, performance results should be regularly evaluated and communicated to all personnel, and high performers should be recognized and rewarded. Some examples of simple employee tasks are outlined in Appendix B.

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[4] See Guidelines for Energy Management at www.energystar.gov.

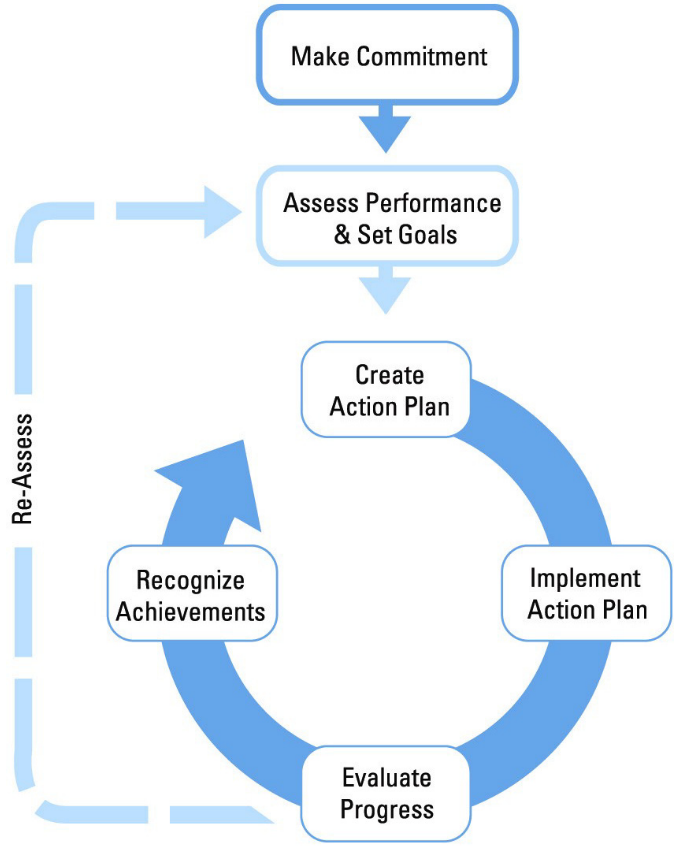

Figure 13. Main elements of a strategic energy management system.

Evaluating progress on the action plan involves the regular review of both energy use data and the activities carried out as part of the action plan. Information gathered during the formal review process helps in setting new performance goals and action plans, and in revealing best practices. Establishing a strong communication program and seeking recognition for accomplishments are also critical steps; both help to build support and momentum for future activities.

A quick assessment of an organization's efforts to manage energy can be made by comparing the current program against the table contained in Appendix C. Appendix D provides the ENERGY STAR energy management assessment matrix to evaluate and score an energy management system.

Internal support for a business energy management program is crucial; however, support for business energy management programs can come from outside sources as well. Facility assessments can be a particularly effective form of outside support. For example, the U.S. Department of Energy (DOE) sponsors 26 Industrial Assessment Centers (IACs) at universities across the United States. These IACs offer small and medium sized manufacturing facilities free assessments of plant energy and waste management performance and recommend ways to improve efficiency. Since the early 1980s, IAC assessments of U.S. petroleum refineries have identified over 100 efficiency and productivity improvement opportunities, with average annual savings of around $135,000 and an average simple payback of 1.3 years per recommendation (IAC, 2012).

The U.S. DOE sponsors similar assessments for large manufacturing plants through its Better Buildings, Better Plants (BBBP) Program, which replaced the *Save Energy Now* Program. Appendix F provides additional information on U.S. DOE programs, as well as a host of other external resources that can aid in identifying energy efficiency opportunities.

6.2 Energy Teams

In addition to allocating sufficient resources, the establishment of an energy team is an important step toward solidifying a commitment to continuous energy efficiency improvement.[5] The energy team should primarily be responsible for planning, implementing, benchmarking, monitoring, and evaluating the organizational energy management program. However, its duties can also include delivering training, communicating results, and providing employee recognition (U.S. EPA, 2006).

In forming an energy team, it is necessary to establish the organizational structure, designate team members, and specify roles and responsibilities. Senior management needs to perceive energy management as part of the organization's core business activities. Thus, the energy team leader will ideally be someone at the corporate level who is empowered by support from senior-level management. The energy team should also include members from each key operational area within an organization and be as multi-disciplinary as possible to ensure a diversity of perspectives. It is crucial to ensure adequate organizational funding for the energy team's activities, preferably as a line item in the normal budget cycle as opposed to a special project.

Prior to the launch of an energy team, a series of team strategy meetings should be held to consider the key initiatives to pursue, as well as potential pilot projects that could be showcased at the program's kickoff. The energy team should then perform facility assessments with key plant personnel at each facility to identify opportunities for energy efficiency improvements. As part of the facility assessments, the energy team should look for best practices in action to help highlight success stories and identify areas for inter-plant knowledge transfer.

A key function of the energy team is to develop mechanisms and tools for tracking and communicating progress and for transferring the knowledge gained through facility assessments across an organization. Examples of such mechanisms and tools include best practice databases, facility benchmarking tools, intranet sites, performance tracking scorecards, and case studies of successful projects. Corporate energy summits and employee energy fairs are also effective means of information exchange and technology transfer.

To sustain the energy team and build momentum for continuous improvement, it is important that progress results and lessons learned are communicated regularly to managers and employees. It is also important that a recognition and rewards program is put in place.

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[5] For a comprehensive overview of establishing, operating, and sustaining an effective energy management team, please consult the U.S. EPA's *Teaming Up to Save Energy* guide available at http://www.energystar.gov/ (U.S. EPA, 2006).

A checklist of key steps for forming, operating, and sustaining an effective energy management team is offered in Appendix E.

6.3 Energy Monitoring and Control Systems

The use of energy monitoring and process control systems can play an important role in energy management and in reducing energy use. These may include sub-metering, monitoring and control systems, which can reduce the time required to perform complex tasks, often improving product and data quality and consistency, and optimizing process operations. Typically, energy and cost savings are 5% or more for industrial applications of process control systems without updated systems in place. Many refineries may already have modern process control systems in place to improve energy efficiency.

Though energy management systems are already widely disseminated in various industrial sectors, the performance of these systems can still be improved, reducing costs and further increasing energy savings. For example, total site energy monitoring and management systems, as opposed to traditional monitoring and management of a limited number of energy streams, can increase the exchange of energy streams between plants on one site. Various suppliers provide site-utility control systems.

Specific energy savings and payback periods for overall adoption of an energy monitoring system vary greatly from plant to plant and company to company. A variety of process control systems are available for virtually any industrial process. A wide body of literature is available assessing control systems in most industrial sectors, such as chemicals and petroleum refining. Table 5 provides an overview of classes of process control systems.

Table 5. Classification of control systems and typical energy efficiency improvement potentials.

System	**Characteristics**	**Typical energy savings (%)**
Monitoring and Targeting	Dedicated systems for various industries, well established in various countries and sectors	Average 8% savings, varying between 1 and 17%
Computer Integrated Manufacturing (CIM)	Improvement of overall economics of process, e.g., stocks, productivity and energy	> 2%
Process control	Moisture, oxygen and temperature control, air flow control "Knowledge based, fuzzy logic"	Savings vary between 1-3%, and can be as high as 18% in exceptional cases

Note: The estimated savings are valid for specific applications (e.g., lighting energy use). The energy savings cannot be added, due to overlap of the systems. Sources: Caffal, 1995, Martin et al., 2000.

Modern control systems are often not solely designed for energy efficiency, but rather for improving productivity, product quality and efficiency of a production line. Applications of advanced control and energy management systems are in varying development stages and can be found in all industries. Control systems result in reductions in downtime, maintenance costs, and processing time, and improved resource and energy efficiency and emissions control. Many modern energy-efficient technologies depend heavily on precise control of process variables and applications of process control systems are growing rapidly. Modern process control systems exist for virtually all industrial processes. Still, opportunities to implement control systems persist, with more modern systems continuously entering the market.

Process control systems depend on information from many stages of the processes. A separate, but related and important area is the development of sensors that are inexpensive to install, reliable, and perform real-time analysis. Current development efforts are aimed at the use of optical, ultrasonic, acoustic, and microwave systems that should be resistant to aggressive environments (e.g., oxidizing environments in furnace or chemicals in chemical processes) and high temperatures. Another innovative measurement technique to detect a variety of gases at trace levels is tunable diode laser (TDL) spectroscopy. In the refinery, it can monitor CO, CH_4 and O_2 in burner flameout applications, and identify process leaks (Hollywood, 2010). The information is used in control systems to adapt the process conditions based on mathematical ("rule"-based) or neural networks and "fuzzy logic" models of the industrial process.

Neural network-based control systems have successfully been used in the cement (kilns), food (baking), non-ferrous metals (alumina, zinc), pulp and paper (paper stock, lime kiln), petroleum refining (process, site), and steel industries (electric arc furnaces, rolling mills). New energy management systems that use artificial intelligence, fuzzy logic (neural network), or rule-based systems mimic the "best" controller, using monitoring data and learning from previous experiences.

Process knowledge based systems (KBSs) have been used in design and diagnostics, but are still not widely used in industrial processes. KBSs incorporate scientific and process information, applying a reasoning process and rules in the management strategy. A demonstration project in a sugar beet mill in the UK using model based predictive control system demonstrated a 1.2 percent reduction in energy costs, while increasing product yield by almost 1% and reducing off-spec product from 11% to 4%. This system had a simple payback period of 1.4 years.

Although energy management systems are already widely disseminated in various industrial sectors, the performance of the systems can still be improved, reducing costs and increasing energy savings further. Research for advanced sensors and controls is ongoing in all sectors, and is funded with both public and private research funds. Several projects within U.S. DOE's Office of Advanced Manufacturing (formerly known as the Industrial Technologies Program) are attempting to develop more advanced control technologies. Sensors and control techniques are identified as key technologies in various development areas, including energy efficiency, mild processing technology, environmental performance and inspection and containment boundary integrity. Outside the United States, Japan and Europe also give much attention to advanced controls. Future steps include further development of new sensors and control systems, demonstrations at a commercial scale, and dissemination of the benefits of control systems in a wide variety of industrial applications.

Process control systems are available for virtually all processes in the refinery, as well as for management of refinery fuel gas, hydrogen, and total site control. In 2005, *Hydrocarbon Processing* published an overview of commercially offered products. Below, examples of processes and site-wide process control systems are discussed, which are selected on the basis of available case studies to demonstrate the specific applications and achieved energy savings.

Refinery-Wide Optimization. Total site energy monitoring and management systems (Kawano, 1996) can increase the exchange of energy streams between plants on one site. Traditionally, only one plant or a limited number of energy streams were monitored and managed. Various suppliers provide site-utility control systems (HCP, 2001). Valero and AspenTech have developed a plant-wide energy optimization model to optimize the flows of intermediates, hydrogen, steam, fuel, and electricity, integrating these within an energy monitoring system. The optimization system includes the cogeneration unit, FCC power recovery and optimum load allocation of boilers, as well as selection of steam turbines or electric motors to run compressors. A plant-wide assessment estimated potential energy savings from such an optimization model at 687,500 MMBtu/year, resulting in a reduction of overall site-wide annual energy use by 1% to 8%. Costs savings were estimated at $2.2 million. With investment costs of $270,000, this would result in a payback period of 0.1 year (Valero, 2003; U.S. DOE-OIT, 2005). Company-wide, Valero expects to save $7 to $27 million annually across 12 refineries (Valero, 2003).

CDU. A few companies supply control equipment for CDUs. Aspen technology has supplied over 70 control applications for CDUs and 10 optimization systems for CDUs. Typical cost savings are between $0.05 and $0.12/bbl of feed, with payback periods of fewer than 6 months. Key Control supplies an expert system advisor for CDUs. It has installed one system at a CDU, which resulted in reduced energy consumption and flaring and increased throughput with a payback of 1 year.

Installation of advanced control equipment at Petrogals Sines refinery in Portugal on the CDU resulted in increased throughputs of 3% to 6% with a payback period of 3 months.

FCC. Several companies offer FCC control systems, including ABB Simcon, AspenTech, Honeywell, Invensys and Yokogawa. Cost savings typically vary between $0.02 and $0.40/bbl of feed with paybacks between 6 and 18 months.

Timmons et al. (2000) report on the advantages of combining an online optimizer with an existing control system to optimize the operation of a FCC unit at the CITGO refinery in Corpus Christi, Texas. The CITGO refinery installed a modern control system and an online optimizer on a 65,000 bpd FCC unit. The combination of the two systems was effective in improving the economic operation of the FCC. The installation of the optimizer led to additional cost savings of approximately \$0.05/barrel of feed to the FCC, which resulted in an attractive payback (Timmons et al., 2000).

In 2001, the ENI refinery in Sanassazzo, Italy, installed in 2001 an optimizer on a FCC unit from Aspen Technology. The system resulted in cost savings of \$0.10/bbl with a payback of less than one year.

Hydrotreater. Installation of a multivariable predictive control (MPC) system was demonstrated on a hydrotreater at a SASOL refinery in South Africa. The MPC aimed to improve the product yield while minimizing the utility costs. The implementation of the system led to improved yield of gasoline and diesel, reduced flaring, a 12% decline in hydrogen consumption, and an 18% reduction in fuel consumption by the heater (Taylor et al., 2000). Fuel consumption for the reboiler increased to improve throughput of the unit. With a payback period of 2 months, the project resulted in improved yield and both direct and indirect (i.e., reduced hydrogen consumption) energy efficiency improvements.

Alkylation. Motiva's Convent, Louisiana refinery implemented an advanced control system for their 100,000 bpd sulfuric acid alkylation plant. The system aims to increase product yield by approximately 1% and reduce electricity consumption by 4.4%, steam use by 2.2%, cooling water use by 4.9%, and chemicals consumption by 5% to 6% (caustic soda by 5.1%, sulfuric acid by 6.4%) (U.S. DOE-OIT, 2000). The software package integrates information from chemical reactor analysis, pinch analysis, information on flows, and information on energy use and emissions to optimize efficient operation of the plant. No economic performance data was provided, but the payback is expected to be rapid, as only additional computer equipment and software had to be installed. The program is available through the Gulf Coast Hazardous Substance Research Center and Louisiana State University. Other companies offering alkylation controls include ABB Simcon, Aspen technology, Emerson, Honeywell, Invensys and Yokogawa. These controls typically result in cost savings of \$0.10 to \$0.20/bbl of feed, with paybacks between 6 and 18 months.

7. Energy Recovery

7.1 Flare Gas Recovery

Flare gas recovery, or zero flaring, is a strategy evolving from the need to improve environmental performance. Conventional flaring practice has operated at a flow greater than the manufacturer's minimum flow rate to avoid damage to the flare. Flared gas may consist of background flaring, including planned intermittent and planned continuous flaring, and most frequently upset or blowdown flaring. In offshore flaring, background flaring may account for up to 50% of all flared gases (Miles, 2001). In refineries, background flaring will generally be much lower than 50%, depending on practices in the individual refinery. Discussions on emissions from flaring by refineries located in the San Francisco Bay Area have highlighted the issue from an environmental perspective (Ezersky, 2002).[6] The report highlighted the higher emissions compared to previous assumptions of the Air Quality district, due to larger volumes of flared gases. The report also demonstrated the differences among various refineries, and among plants within the refineries. Reducing flaring not only results in reduced air pollutant emissions and increased energy efficiency when replacing fuels, but also minimizes negative publicity surrounding flaring.

Emissions can be further reduced by improved process control equipment and new flaring technology. Development of gas-recovery systems, including new ignition systems with low-pilot-gas consumption or new ballistic ignition systems that eliminate pilots can reduce the amount of flared gas considerably (see section 19.3). Development and demonstration of new ignition systems without a pilot may result in increased energy efficiency and reduced emissions.

Reduction of flaring can be achieved by improved recovery systems, including installing recovery compressors and collection in storage tanks. Besides the reduction of air pollution and emissions, a flare gas recovery system reduces flaring noise, operation and maintenance costs, thermal radiation, and fuel gas and steam consumption. In addition, process stability and flare tip life are increased without having any impact on the existing safety relief system (Zadakbar et al., 2010). Provided that the recovered fuel off-sets the purchase of natural gas, flare gas recovery is generally cost-effective for recovering flare gas exceeding 20 MMBtu/hr (U.S. EPA, 2010). Various refineries in the United States have installed flare gas recovery systems, including Chevron in Pascagoula, Mississippi, ConocoPhillips in Ponca City, Oklahoma, Shell in Martinez, California, Flint Hill Resources in Corpus Christi, Texas, and Pine Bend, Minnesota, and even some smaller refineries, such as Lion Oil Co. in El Dorado, Arkansas.

An assessment of the Valero Houston refinery revealed that installing a compressor and associated equipment to recover flare gas from three existing flare systems will save 130,000

[6] Chevron commented on the report by the Bay Area Air Quality Management District on refinery flaring. The comments were mainly directed towards the VOC-calculations in the report and an explanation of the flaring practices at the Chevron refinery in Richmond, CA (Hartwig, 2003).

MMBtu/year. Flare gas recovery at this facility is expected to result in cost savings of $420,000, with a payback period of 2.4 years (U.S. DOE-OIT, 2005).

Installation of two flare gas recovery systems at the 65,000 bpd Lion Oil Refinery in El Dorado, Arkansas, in 2001 has reduced flaring to near zero levels (Fisher and Brennan, 2002). The refinery only employs flaring in emergencies where the total amount of gas may exceed the capacity of the recovery unit. The recovered gas is compressed and used in the refinery's fuel system. No information on energy savings or payback periods were given for this particular installation.

John Zink Co., the installer of the recovery system, reports that the payback period of recovery systems is typically less than two years (Blanton, 2010).

7.2 Power recovery

Numerous processes run at elevated pressures, presenting an opportunity for power recovery from the pressure in the flue gas. The primary application for power recovery in the petroleum refinery is the fluid catalytic cracker (FCC). However, power recovery can also be applied to hydrocrackers or other equipment operated at elevated pressures. Modern FCC designs use a power recovery turbine or turbo expander to recover energy from pressure. The recovered energy can be used to drive the FCC compressor or to generate power. Power recovery applications for FCC are characterized by large volumes of high temperature gases at relatively low pressures operating continuously over long periods of time between maintenance stops (> 32,000 hours). There is significant long-term experience with power recovery turbines for FCC applications. Various designs are marketed, and newer designs tend to be more efficient in power recovery. Generally, installation of a power recovery system can reduce the Energy Intensity Index (EII) of a refinery by 7% to 10% (Carbonetto and Pecchi, 2011). Recovery turbines are supplied by a small number of global suppliers, including GE Power Systems.

Many refineries in the United States and around the world have installed recovery turbines. Valero has upgraded the turbo expanders at its refineries in Houston, Texas, Corpus Christi, Texas and Wilmington, California refineries. Valero's Houston refinery replaced an older power recovery turbine to enable increased blower capacity to allow an expansion of the FCC. At the Houston refinery the re-rating of the FCC power recovery train led to power savings of 22 MW, and will export up to 4 MW of additional power to the grid (Valero, 2003). Valero's St. Charles refinery also retrofitted the power recovery turbine of the FCC in order to increase refinery capacity. The 36 MW recovery turbine is one of the largest in the world and will offset external power requirements of the refinery (Elliot, 2008). Petro Canada's Edmonton refinery replaced an older turbo expander with a more efficient unit in October 1998, saving around 18 TBtu annually.

Power recovery turbines can also be applied at hydrocrackers. Power can be recovered from the pressure difference between the reactor and fractionation stages of the process. In 1993, the Total refinery (currently called the Zeeland Refinery) in Vlissingen, the Netherlands, has installed a 910 kW power recovery turbine to replace the throttle at its hydrocracker (45,653 barrel/calendar day). The cracker operates at 160 bar. The power recovery turbine produces about 7.3 million kWh/year (assuming 8000 hours/year). The investment was equal to $1.2 million

(1993$). This resulted in a payback period of approximately 2.5 years under the conditions in the Netherlands (CADDET, 2003).

The total potential for power export of U.S. refineries is estimated at 170 MW by Bailey and Worrell (2005). Their analysis indicates that cost-effective installation of power recovery turbines is possible at 50% of FCC capacity, producing approximately 720 GWh of power annually. The additional estimated potential for hydrocrackers is 29 MW, producing about 250 GWh.

8. Steam Generation and Distribution

Steam comprises an estimated 30% of all onsite energy use in U.S. refineries. Off-site purchased steam represents only about 6% of total energy consumption at petroleum refineries in the Unites States (EIA, 2012). Steam can be generated through waste heat recovery from processes, cogeneration and boilers. In most refineries, steam will be generated by all three sources, while some smaller refineries may not have cogeneration equipment installed. While the exact size and use of a modern system varies greatly, there is an overall pattern that steam systems follow.

Figure 14 depicts a schematic presentation of a steam system. Treated cold feed water is fed to the boiler, where it is heated to form steam. Chemical treatment of the feed water is required to remove impurities, which would otherwise collect on the boiler walls. Even though the feed water has been treated, some impurities still remain and can build up in the boiler water. As a result, water is periodically drained from the bottom of the boiler in a process known as blowdown. The generated steam travels along the pipes of the distribution system to get to the processes where the heat will be used. Sometimes the steam is passed through a pressure reduction valve if the process requires lower pressure steam. As the steam is used to heat processes, and even as it travels through the distribution system, the steam cools and partially condenses. This condensate is removed by a steam trap, which allows condensate to pass through, but blocks the passage of steam. The condensate can be recirculated to the boiler, thus recovering some heat and reducing the need for fresh treated feed water. The recovery of condensate and blowdown will also reduce the costs of boiler feed water treatment. For example, optimization of blowdown steam use at Valero's Houston refinery led to cost savings of $213,500/year (Valero, 2003).

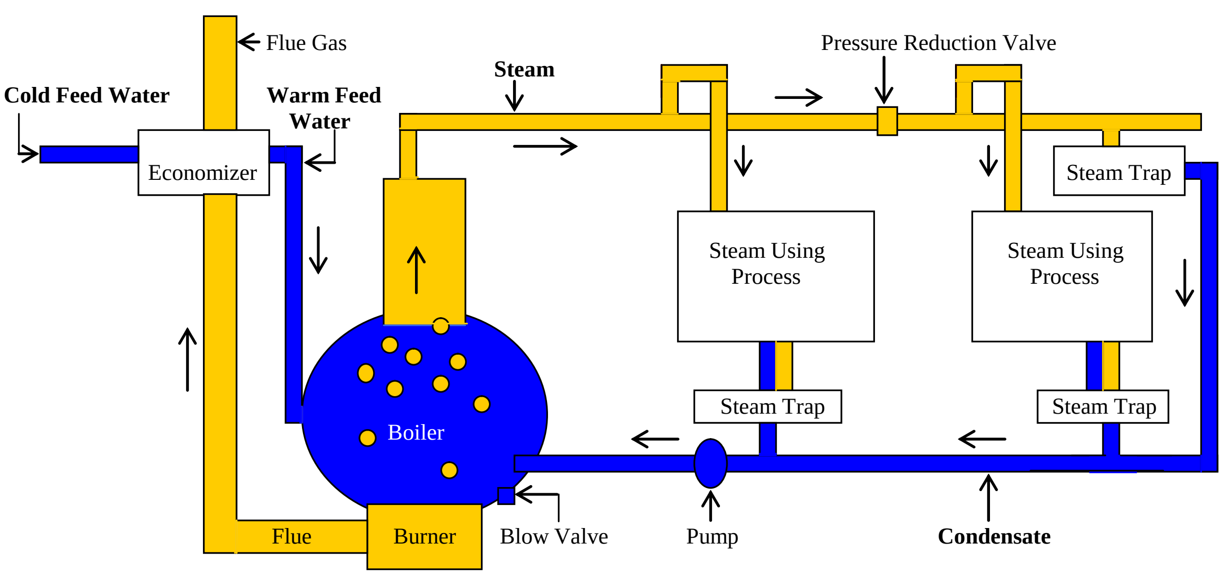

Figure 14. Schematic presentation of a steam production and distribution system.

The refining industry uses steam for a wide variety of purposes, the most important being process heating, drying or concentrating, steam cracking, and distillation. Whatever the use or the source of the steam, efficiency improvements in steam generation, distribution and end-use are possible. An earlier study by the U.S. Department of Energy estimated the overall potential for energy savings in petroleum refineries at over 12% (U.S. DOE-OIT, 2002). It is estimated that steam distribution and cogeneration offer the most cost-effective short-term energy efficiency opportunities. This section focuses on the steam generation in boilers, including waste heat boilers, and on steam distribution. Table 6 summarizes the boiler efficiency measures, while Table 7 summarizes the steam distribution system measures.

Steam, like any other secondary energy carrier, is expensive to produce and supply. The use of steam should be carefully considered and evaluated. Steam is often generated at higher pressures or in larger volumes than needed at a particular time. These inefficiencies may result in steam systems reducing pressure or venting steam to the atmosphere. It is therefore strongly recommended to evaluate the appropriate pressure level for steam systems based on production schedules. If steam generation pressure cannot be reduced, it may still be possible to recover the energy through a turbo expander or steam expansion turbine (see section 18.3). Excess steam generation can be reduced through improved process integration (see section 9.2) and improved management of steam flows in the refinery (see section 6.3). Many refineries operate multiple boilers. An assessment of the refinery in Martinez, California, found that scheduling steam boilers on the basis of efficiency (and minimizing losses in the steam turbines) can result in annual energy savings equaling $5.4 million (U.S. DOE-OIT, 2002b).

8.1 Boilers

Boiler feed water preparation. Depending on the quality of incoming water, the boiler feed water (BFW) may need to be pre-treated. Various technologies may be used to clean this water. One new technology uses reverse osmosis (RO) to draw pre-filtered water through a semi-permeable membrane. These types of membrane and reverse osmosis technologies are increasingly common in water treatment (Martin et al., 2000). Membrane processes are very reliable, but require semi-annual cleaning and periodic replacement to maintain performance.

The Flying J Refinery in North Salt Lake, Utah (currently owned by Big West Oil) installed a RO-unit to remove hardness and reduce the alkalinity from boiler feed water, replacing a hot lime water softener. The unit began operating in 1998, and has reduced boiler blowdown from 13.3% to 1.5% of steam produced, in addition to reducing chemical use, maintenance, and waste disposal costs (U.S. DOE-OIT, 2001). With an investment of $350,000 and annual benefits of approximately $200,000, the payback period amounted to less than 2 years. Other refineries that have a RO-units installed to treat wastewater and recycle it as boiler feed water include Suncor in Commerce City, Chevron in Pascagoula and Richmond, BP in Carson, and ConocoPhillips in Wilmington.

Improve boiler process control. Flue gas monitors are used to maintain optimum flame temperature, and to monitor carbon monoxide (CO), oxygen and smoke. The oxygen content of the exhaust gas is a combination of excess air (which is deliberately introduced to improve safety or reduce emissions) and air infiltration (air leaking into the boiler). By combining an oxygen monitor with an intake airflow monitor, it is possible to detect even small leaks. A small 1% air infiltration will result in 20% higher oxygen readings. A higher CO or smoke content in the exhaust gas is a sign that there is insufficient air to complete fuel burning. Using a combination of CO and oxygen readings, it is possible to optimize the fuel-to-air mixture for high flame temperatures, maximizing energy efficiency and emissions reductions. Typically, this measure is only financially attractive for large boilers, because smaller boilers often will not recover the initial capital cost as rapidly. The payback of improved process control is approximately 0.5 years[7] (IAC, 2012).

Reduction of flue gas quantities. Excessive flue gas often results from leaks in the boiler and/or the flue. These leaks reduce the heat transferred to the steam and increase pumping requirements. Leaks are often easily repaired, saving 2% to 5% of the energy previously used by the boiler. This measure differs from flue gas monitoring in that it consists of a periodic repair based on visual inspection. The savings from this measure and from flue gas monitoring are not cumulative, as they both address the same losses.

Reduction of excess air. Boilers must be fired with excess air to ensure complete combustion and to reduce the presence of carbon monoxide in the unburned fuel in exhaust gases. When too much excess air is used to burn fuel, energy is wasted because excessive heat is transferred to the air rather than to the steam. Increasing air content slightly above of the ideal stoichiometric fuel-to-air ratio is required for safety, and to reduce emissions of nitrogen oxides (NO_x). Approximately 10% to 15% excess air in the flue gas (around 2% to 3% excess oxygen) is generally sufficient (U.S. DOE, 2012). An often stated rule of thumb is that boiler efficiency can be increased by 1% for each 15% reduction in excess air (U.S. DOE, 2012b). Numerous industrial case studies indicate that the payback period for this measure is less than one year (IAC, 2012).

The percentage of oxygen in the flue gas can be analyzed by inexpensive gas-absorbing test kits. For a boiler system with annual fuel costs of more than $50,000, a more expensive hand-held, computer-based analyzer (ranging from $500 to $1,000) that reports the percentage oxygen, stack gas temperature, and boiler efficiency, is recommended (U.S. DOE, 2012b).

Improve insulation. New materials insulate better and have a lower heat capacity. Savings between 6% and 26% can be achieved if this improved insulation is combined with improved heater circuit controls. This improved control is required to maintain the output temperature range of the old firebrick system. As a result of the ceramic fiber's lower heat capacity, the output temperature is more vulnerable to temperature fluctuations in the heating elements (Caffal, 1995). The shell losses of a well-maintained boiler should be less than 1%.

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[7]The Industrial Assessment Center (IAC) database contains case study data for a wide range of industrial energy efficiency measures. It gives a wide variety of information, including implementation costs and savings for each case study. Using this information, a simple payback for each case was calculated. An overall payback for a particular technology was calculated by averaging all the individual cases. In order to accurately represent applicable technology for the petroleum refining industry, only the SIC code that pertained to this industry (i.e., SIC 2911) was sampled. We calculated an overall payback for a technology by averaging all the individual cases.

Boiler maintenance. A simple maintenance program to ensure that all components of the boiler are operating at peak performance can result in substantial savings. In the absence of a good maintenance system, the burners and condensate return systems can wear or shift out of adjustment. These factors can end up costing a steam system up to 20% to 30% of initial efficiency over 2 to 3 years. On average, the energy savings associated with improved boiler maintenance are estimated at 10%. Improved maintenance may also reduce the emission of criteria air pollutants.

Fouling of the fireside of the boiler tubes or scaling on the waterside of the boiler should also be controlled. The result of fouling and scaling is overheating of boiler tube metal, tube failures, and loss of energy efficiency. Even on small boilers, prevention of scaling can yield significant energy savings. Fouling and scaling are more of a problem with coal-fed boilers than natural gas or oil-fed ones, so boilers that burn solid fuels such as coal should be checked more frequently than liquid boilers. Tests show that a soot layer of 0.03 inches (0.8 mm) reduces heat transfer by 9.5%, while a 0.18 inch (4.5 mm) layer reduces heat transfer by 69% (CIPEC, 2001). For water side scaling, 0.04 inches (1 mm) of buildup can increase fuel consumption by 2% (CIPEC, 2001; U.S. DOE, 2012c).

Burner replacement. According to a study conducted for the U.S. Department of Energy, roughly half of the U.S. industrial boiler population is over 40 years old (EEA, 2005). A boiler typically runs as well as the burner performs. Therefore, replacing old burners with more efficient modern burners can lead to significant energy savings. An efficient burner provides a proper air-to-fuel ratio throughout the range of firing rates (U.S. DOE, 2012). Energy and cost savings vary widely based on the condition and efficiency of the burners being replaced. For example, the payback time for a new burner that provides a boiler efficiency improvement of 2% will be less than one year (U.S. DOE, 2012).

Condensate return. For indirect uses of steam, returning hot condensate to boilers for reuse saves energy and reduces the need for treated boiler feed water. Typically, fresh feed water must be treated to remove solids that might accumulate in the boiler; however, returning condensate to a boiler can substantially reduce the amount of purchased chemical required to accomplish this treatment. In addition, less condensate discharge reduces disposal costs. Significant fuel savings result from the return of relatively hot condensate (130°F to 225°F), reducing the amount of cold makeup water (50°F to 60°F) that must be heated. The fact that this measure can result in substantial energy and purchased chemical cost savings makes building a return piping system attractive (U.S. DOE, 2012d). This measure has already been incorporated into many locations where implementation barriers are low. Care has to be taken to design the recovery system to reduce efficiency losses (van de Ruit, 2000). Energy savings are estimated at approximately 10% of the total steam energy content of a typical system (U.S. DOE, 2012d), with a payback of 0.7 years (IAC, 2012) for those sites with insufficient condensate return. An additional benefit of condensate recovery is the reduction of the blowdown flow rate resulting from improved boiler feedwater quality.

An assessment at the American Refining Group refinery in Bradford, Pennsylvania identified the potential to increase condensate return from 25% to 40%, resulting in $140,000 in cost savings and 27,000 MMBtu of energy savings (ARG, 2007).

An impact analysis of CITGO's Corpus Christi, Texas refinery showed that an additional 5% condensate recovery and return will result in savings of about 15,750 MMBtu and $136,000 per year (CITGO, 2007).

Flue gas heat recovery. Heat recovery from flue gas often represents the best opportunity for heat recovery in steam systems (CIPEC, 2001). Heat from flue gasses can be used to preheat boiler feed water in an economizer. While this measure is fairly common in large boilers, there is often potential for further heat recovery. The limiting factor for flue gas heat recovery is that one must ensure that the economizer wall temperature does not drop below the dew point of acids in the flue gas (such as sulfuric acid in sulfur-containing fossil fuels). Traditionally, this is done by keeping the flue gases exiting the economizer at a temperature significantly above the acid dew point. In fact, the economizer wall temperature is more dependent on the feed water temperature than flue gas temperature because of the high heat transfer coefficient of water. As a result, it makes more sense to preheat the feed water close to the acid dew point before it enters the economizer. This allows the economizer to be designed so that the exiting flue gas is just above the acid dew point. Typically, one percent of fuel use is saved for every 40°F (25°C) reduction in exhaust gas temperature (Ganapathy, 1994). A conventional economizer would result in savings between 2% and 4%, while a condensing economizer could result in energy savings of 5% to 8% (Gardner, 2008). Due to the risk of corrosion, the use of condensing economizers is limited to boilers using clean fuels. The payback period for these systems is approximately 2 years (U.S. DOE, 2012e).

Minimize boiler blowdown. Boiler blowdown is important for maintaining proper steam system water properties, and must be conducted periodically to minimize boiler deposit formation. However, excessive blowdown will waste energy, as well as water and chemicals. The optimum blowdown rate depends on a number of factors, including the type of boiler and its water treatment requirements, but typically ranges from 4% to 8% of the boiler feed water flow rate (U.S. DOE, 2012g). Automatic blowdown systems can be installed to optimize blowdown rates by regulating the volume of water discharged from the boiler in relation to the concentration of dissolved solids present.

For a natural gas-fired steam boiler of 100,000 lb/hr, an automatic blowdown control system can reduce the blowdown rate from 8% to 6%. This will result in annual fuel savings of 7,860 MMBtu per year (U.S. DOE, 2012g). In many cases, the savings of an automatic blowdown control system can provide a payback of between 1 and 3 years (U.S. DOE, 2012f).

At the Bradford refinery of the American Refining Group in Pennsylvania, a reduction of the blowdown rate from 9% to 2% would result in energy savings of 1,750 MMBtu/year, saving $23,000/year. Savings identified are not very large, since there is already a heat recovery system installed on the boiler blowdown (ARG, 2007).

An assessment of Valero's Houston, Texas refinery showed that the installation of an automatic blowdown control system on three steam boilers could reduce boiler feedwater and chemical costs by approximately $100,000 per year. With capital costs of $180,000, the simple payback would be 1.8 years. Energy savings have not yet been identified (U.S. DOE-OIT, 2005).

Blowdown steam recovery. Boiler blowdown is important for maintaining proper steam system water properties. However, blowdown can result in significant thermal losses if the steam is not recovered for beneficial use. Blowdown steam is typically low grade, but can be used for space heating and feed water preheating. In addition to energy savings, blowdown steam recovery may reduce the potential for corrosion damage in steam system piping. For larger high-pressure boilers the losses may be less than 0.5%. It is estimated that this measure can save 1.3% of boiler fuel use for all boilers below 100 MMBtu/hr (approximately 5% of all boiler capacity in refineries). The payback period of blowdown steam recovery is approximately 2.5 years (IAC, 2012).

A steam energy savings assessment (ESA) at the American Refining Group refinery in Bradford, Pennsylvania, showed a potential saving of 7,000 MMBtu/year by increasing the efficiency of the blowdown heat exchanger. Cost savings were identified at $28,000/year at 2007 prices (ARG, 2007).

Table 6. Summary of energy efficiency measures in boilers.

Measure	**Fuel Saved**	**Payback Period (years)**	**Other Benefits**
Improved process control	3%	0.6	Reduced Emissions
Reduced flue gas quantity	2-5%	-	Cheaper emission controls
Reduced excess air	1% improvement for each 15% less excess air	-	
Improved insulation	6-26%	Unknown	Faster warm-up
Boiler maintenance	10%	0	Reduced emissions
Flue gas heat recovery	1%	2	
Blowdown steam heat recovery	1.3%	2.5	Reduced damage to structures (less moist air is less corrosive).
Alternative fuels	Variable	-	Reduces solid waste stream at the cost of increased air emissions

8.2 Steam Distribution System Energy Efficiency Measures

When designing new steam distribution systems it is very important to take into account the velocity and pressure drop (Van de Ruit, 2000). This reduces the risk of oversizing a steam pipe, which can increase costs and lead to greater heat loss. An undersized pipe may lead to erosion and increased pressure drop. Installations and steam demands change over time, which may lead to under-utilization of steam distribution capacity utilization and further heat loss. However, it may be too expensive to optimize the system for changing steam demands. Still, checking for excess distribution lines and shutting off those lines is a cost-effective way to reduce steam distribution losses. Other maintenance measures for steam distribution systems are described below.

Steam distribution controls. In refineries often one or more boilers are kept on standby in case of failure of the operating boiler fails. The steam production during standby can be reduced to virtually zero by modifying the burner, combustion air supply, and boiler feedwater supply. By installing an automatic control system the boiler can reach full capacity within 12 minutes. Installing the control system and modifying the boiler can result in energy savings up to 85% of the standby boiler, depending on the use pattern of the boiler.

The Kemira Oy ammonia plant at Rozenburg, the Netherlands, applied this system to a small 40 t/hr steam boiler, reducing the standby steam consumption from 6 t/hr to 1 t/hr. This resulted in energy savings of 54 TBtu/year. Investments were approximately $270,000 (1991$), resulting in a payback period of 1.5 years at this particular plant (CADDET, 1997b).

Improve insulation. Using more insulating material or the best insulation material for the application can save energy in steam distribution systems. Crucial factors in choosing insulating material include low thermal conductivity, dimensional stability under temperature change, resistance to water absorption, and resistance to combustion. Other characteristics of insulating material may also be important depending on the application, such as tolerance of large temperature variations, tolerance of system vibrations, and adequate compressive strength where the insulation is load bearing (Baen and Barth, 1994). Improving the insulation on the existing stock of heat distribution systems would save an average of 3% to 13% in all systems (U.S. DOE-OIT, 1998) with an average payback period of roughly 1 year (IAC, 2012). The U.S. Department of Energy has developed the software tool 3E-Plus to evaluate the optimal insulation for steam systems (see Appendix F).

Removable insulating pads are commonly used in industrial facilities for insulating flanges, valves, expansion joints exchangers, pumps, turbines, tanks and other surfaces. Insulating pads can be easily removed for periodic inspection or maintenance, and replaced as needed. Insulating pads also contain built-in acoustical barriers to help control noise (U.S. DOE, 2012j). Any surface that reaches temperatures over 120°F should be insulated. The U.S. Department of Energy estimates that the installation of removable insulation on valves, pipes, and fittings can reduce steam system energy use by 1% to 3% (U.S. DOE-OIT, 2006).

An assessment of the Valero Houston refinery identified several uninsulated or under-insulated steam lines and equipment. Insulation of the steam system will result in annual cost savings of

$165,000 and fuel savings of 52,000 MMBtu. The simple payback period of this measure is 0.6 years (U.S. DOE-OIT, 2005).

Insulation maintenance. It is often found that after heat distribution systems have undergone some form of repair, the insulation is not replaced. Damaged or wet insulation should be repaired or replaced to avoid compromising its insulating value. In addition, some types of insulation can become brittle or rot over time. As a result, a regular inspection and maintenance system for insulation can also save energy (Zeitz, 1997).

Steam trap improvement. Using modern thermostatic element steam traps can reduce energy use while also improving reliability. The main efficiency advantages offered by these traps are that they open when the temperature is very close to that of saturated steam (within 4°F or 2°C), purge non-condensable gases after each opening, and are open on startup to allow a fast steam system warm-up. These traps also have the advantage of being highly reliable and useable for a wide variety of steam pressures (Alesson, 1995). A new steam trap design is the venturi orifice steam trap, which is better suited for varying loads than traditional mechanical steam traps (Gardner, 2008).

Steam trap maintenance. A simple program of checking steam traps to ensure that they are operating properly can save significant amounts of energy for very little cost. In the absence of a steam trap maintenance program, after 3 to 5 years it is common to find between 15% and 30% of installed steam traps malfunctioning (U.S. DOE, 2012h). Annual failure rates are estimated at 10% or more (Gardner, 2008). In a steam system with a regular maintenance program, leaking should not be found in more than 5% of the steam traps. Energy savings for a regular system of steam trap checks and follow-up maintenance is conservatively estimated at 10% (Jones, 1997; Bloss et al., 1997). Several industrial case studies suggest that investments for repair or replacement steam traps are very low, resulting in a payback period of only a few months or less (IAC, 2012).

An assessment of the Flying J Refinery in North Salt Lake, Utah (currently owned by Big West Oil) identified annual savings of $147,000 by repairing leaking steam traps (Brueske et al., 2002).

A plant-wide assessment of the Valero Houston refinery found that more than 200,000 MMBtu could be saved annually by repairing and maintaining steam traps. This would result in cost savings of $655,000 with a simple payback time of 0.2 years (U.S. DOE-OIT, 2005).

At a petroleum refinery in Louisiana, a survey found out that only 46% of the steam traps were operating correctly. Repair and maintenance resulted in savings of $1.3 million in steam losses. The project offered a 5.3 months payback period (Spirax-Sarco, 2012).

Monitor steam traps automatically. Attaching automated monitors to steam traps in conjunction with a maintenance program can save even more energy without significantly increased costs. This measure is an improvement over steam trap maintenance alone, because it gives quicker notice of steam trap failure and can detect when a steam trap is not performing at peak efficiency. Employing steam trap monitoring is estimated to save an additional 5% of energy use over steam trap maintenance, with a payback of approximately 1 year[8] (Johnston, 1995; Jones, 1997). Systems that are able to implement steam trap maintenance are also likely to be able to implement automatic monitoring.

Leak repair. As with steam traps, steam distribution piping networks often have leaks that go undetected without a program of regular inspection and maintenance. In addition to saving up to 3% of energy costs for steam production, having such a program can reduce the likelihood of having to repair major leaks (U.S. DOE-OIT, 1998). On average, leak repair has a payback period of a few months or less (IAC, 2012).

Flash steam recovery. When a steam trap purges condensate from a pressurized steam distribution system to ambient pressure, flash steam is produced. As with flash steam produced by boiler blowdown, steam trap flash steam can be recovered and used for low grade facility applications, such as space heating or feed water preheating (Johnston, 1995).

The potential for this measure is site dependent, as its cost effectiveness depends on whether areas where low-grade heat is useful are located close to steam traps. Where feasible, this measure can be easily implemented and can save considerable energy. Many sites will use multi-pressure steam systems. In this case, flash steam formed from high-pressure condensate can be routed to reduced pressure systems.

Vulcan Chemicals in Geismar, Louisiana, implemented a flash steam recovery project at one of the processes at their chemical plant. The project recovers 100% of the flash steam and has resulted in net energy savings of 2.8% (Bronhold, 2000).

In an example from the food industry, an analysis of a U.S. based food processing facility predicted that the installation of a flash steam recovery system used for feed water preheating would save the plant around $29,000 in fuel costs annually at a payback period of less than 1.8 years (Iordanova et al., 2000).

Table 7. Summary of energy efficiency measures in steam distribution systems.

Measure	Fuel Saved	Payback Period (years)	Other Benefits
Improved insulation	3-13%	1	
Improved steam traps	Unknown	Unknown	Greater reliability

[8] Calculated based on a UK payback of 0.75 years. The U.S. payback is longer because energy prices in the United States are lower, while capital costs are similar.

Measure	Fuel Saved	Payback Period (years)	Other Benefits
Steam trap maintenance	10-15%	0.1	
Automatic steam trap monitoring[9]	5%	1	
Leak repair	3-5%	0.2	Reduced requirement for major repairs
Flash steam recovery and condensate return	83%[10]	Unknown	Reduced water treatment costs
Condensate return alone	10%	0.7	Reduced water treatment costs

[9] In addition to a regular maintenance program.

[10] Includes flash steam recovery from the boiler. Although this represents actual savings achieved in a case study, it seems much too high to be a generally applicable savings number. As a result, it is not included in our total savings estimate.

9. Heat Exchangers and Process Integration

Heating and cooling are operations found throughout the refinery, with streams being heated and cooled multiple times within a single process. Optimization of the use and design of heat exchangers is a key area for energy efficiency improvement.

9.1 Heat transfer - Fouling

Heat exchangers are used throughout the refinery to recover heat from processes and transfer heat to the process flows. Next to efficient integration of heat flows throughout the refinery (see process integration below), the efficient operation of heat exchangers is a major area of interest. In a complex refinery, most processes occur under high temperature and pressure conditions. The management and optimization of heat transfer among processes is therefore key to increasing overall energy efficiency. Fouling, a deposit buildup in units and piping, impedes heat transfer, requiring the combustion of additional fuel. For example, the processing of many heavy crude oils in the United States increases the likelihood of localized coke deposits in the heating furnaces, thereby reducing furnace efficiency and creating potential equipment failure. Total costs associated with fouling are significant and affect both capital and operating costs. The increase in capital costs is the result of heat exchanger equipment being generally designed to compensate for the loss in effectiveness of heat transfer. Operating costs are increased as a result of the increased energy consumption, additional maintenance and cleaning, and the use of antifouling additives (Rodriguez and Smith, 2007). An estimate by the Office of Industrial Technology (now named AMO) at the U.S. Department of Energy noted that the cost penalty for fouling could be as much as $2 billion annually in material and energy costs. The problem of fouling is expected to increase with the trend towards processing heavier crudes.

Fouling is a product of several process variables and heat exchanger design. Fouling may follow a combination of different mechanisms (Bott, 2001). Several methods of investigation are attempting to reduce fouling, including the use of sensors to detect early fouling, physical and chemical methods to create high temperature coatings (without equipment modification), the use of ultrasound, and improved long term design and operation of facilities. The U.S. Department of Energy initially funded preliminary research into this area, but funding has been discontinued (Huangfu, 2000; Bott, 2000). Worldwide, research in fouling reduction and mitigation is continuing (Polley and Pugh, 2002; Polley et al., 2002; Rodriguez and Smith, 2007) by focusing on understanding the principles of fouling and redesign of heat exchangers and reactors. Various methods to reduce fouling focus on process control, temperature control and regular maintenance and cleaning of the heat exchangers (either mechanically or chemically) or retrofitting the reactor tubes (Barletta, 1998).

Fouling is an important factor for efficiency losses in the CDU, within which the crude preheater is especially susceptible to fouling (Barletta, 1998). Initial analysis of the fouling effects of a 100,000 bbl/day crude distillation unit found an additional heating load of 12.3 kBtu/barrel (13.0 MJ/barrel) of processes (Panchal and Huangfu, 2000). Reducing this additional heating load could results in significant energy savings.

One of the commercially available heat exchanger designs that have a lower fouling rate compared to the traditional shell-and-tube heat exchanger is the plate heat exchanger. Plate heat exchangers have corrugated plates stacked and welded together forming helix design flow channels. The high turbulence in this type of exchanger results in the lowering of fouling rates due to high shear forces on the exchanger walls. Another benefit of this high turbulence is a three to five times increase in thermal efficiency compared to the shell-and-tube design. When considering retrofit with plate heat exchangers, the layout and capacity of the refinery process is crucial. A study on energy efficiency in hydrotreaters (Milosevic and Shire, 2011) observed that in retrofit situations, the size of many hydrotreaters is below the critical size for plate-type heat exchangers to be retrofitted economically. Plate heat exchangers are already used extensively in refinery operations worldwide.

Fouling was identified as a major energy loss in an assessment of the Equilon refinery in Martinez, California (now owned by Shell). Regular cleaning of heat exchangers and maintenance of insulation would result in estimated annual savings of over $14 million at a total expenditure of $9.85 million (U.S. DOE-OIT, 2002b). Hence, the simple payback period is around 8 months.

A study of European refineries identified overall energy savings of 0.7% by cleaning the heat exchanger tubes of the CDU and other furnaces, resulting in an estimated payback period of 0.7 years.

The crude preheater at a North American refinery was fouling at an unacceptable rate, resulting in loss of furnace inlet temperature and the need for frequently cleaning of exchangers. A simulator model was used to analyze data and give exchanger cleaning recommendations. A cleaning study, run on a data set from 2004, showed that the cleaning of one of the exchangers could increase the furnace inlet temperature by 11˚C. This would result in savings of $2,500/day (Mason and McAteer, 2008).

9.2 Process integration

Process integration or pinch technology refers to the exploitation of potential synergies that are inherent in any system that consists of multiple components working together. In plants that have multiple heating and cooling demands, the use of process integration techniques may significantly improve efficiencies.

Developed in the early 1970s, process integration is now an established methodology for continuous processes (Linnhoff, 1992; CADDET, 1993). The methodology involves linking hot and cold streams in a thermodynamic-optimal way (i.e., not over the so-called ‘pinch’). Process integration is the art of ensuring that the components are well suited and matched in terms of size, function and capability. Pinch analysis takes a systematic approach to identifying and correcting the performance limiting constraint (or pinch) in any manufacturing process (Kumana, 2000). It was developed originally in the late 1970s at the University of Manchester in England, among other locations (Linnhoff, 1993), in response to the “energy crisis” of the 1970s and the need to reduce steam and fuel consumption in oil refineries and chemical plants by optimizing the design of heat exchanger networks. Since then, the pinch approach has been extended to resource conservation in general, whether the resource is capital, time, labor, electrical power, water or a specific chemical species such as hydrogen.

The critical innovation in applying pinch analysis was the development of "composite curves" for heating and cooling, which represent the overall thermal energy demand and availability profiles for the process as a whole. When these two curves are drawn on a temperature-enthalpy graph, they reveal the location of the process pinch (the point of closest temperature approach), and the minimum thermodynamic heating and cooling requirements. These are called the energy targets. The methodology involves first identifying the targets and then following a systematic procedure for designing heat exchanger networks to achieve these targets. The optimum approach temperature at the pinch is determined by balancing the capital-energy tradeoffs to achieve the desired payback. The procedure applies equally well to both new designs and to retrofitting existing plants.

The analytical approach to this analysis has been well documented in literature (Kumana, 2000b; Smith, 1995; Shenoy, 1994). Energy savings potential using pinch analysis far exceeds that from well-known conventional techniques such as heat recovery from boiler flue gas, insulation, and steam trap management.

Pinch analysis, and competing process integration tools, have been developed further in the past years. The most important advances in energy efficiency are the inclusion of alternative heat recovery processes, such as heat pumps and heat transformers, as well as the development of pinch analysis for batch processes. Furthermore, pinch analysis should be used in the design of new processes and plants, as process integration goes beyond optimization of heat exchanger networks (Hallale, 2001). Even in new designs, additional opportunities for energy efficiency improvement can be identified. Pinch analysis has also been extended to water recovery efficiency and hydrogen recovery (hydrogen pinch, see also below). Water used to be seen as a low-cost resource to the refinery and was used inefficiently. However, as the standards and costs for waste water treatment and feedwater makeup increase, the industry has become more aware of water costs. In addition, large amounts of energy are used to process and move water through the refinery. Hence, water savings will lead to additional energy savings. Water pinch can be used to develop targets for minimal water use by reusing water in an efficient manner. Optimization software has been developed to optimize investment and operation costs for water systems in a plant (Hallale, 2001). New tools have been developed to optimize water and energy use in an integrated manner (Wu, 2000). Water pinch has primarily been used in the food industry, with up to 50% reductions in water intake reported (Polley and Polley, 2000). Dunn and Bush (2001) report that using of water pinch to optimize water use in chemical plants operated by Solutia has resulted in sufficient water use reductions to allow expansion of production with no net increase in water use. No water pinch analysis studies specific to the petroleum refining industry were found. Major oil companies, including BP and ExxonMobil, have applied hydrogen pinch analysis at select refineries.

Total site pinch analysis. A total site pinch analysis has been applied by over 40 refineries around the world to find optimum site-wide utility levels by integrating heating and cooling demands of various processes, and by allowing the integration of CHP into the analysis. Process integration analysis of existing refineries and processes should be performed regularly, as continuous changes in product mix, mass flows and applied processes can provide new or improved opportunities for energy and resource efficiency.

Major refineries that have applied total site pinch analysis include Agip (currently called ENI, Italy), BP, Chevron, ExxonMobil (in the Netherlands and UK), and Shell (several European plants). Typical savings identified in these site-wide analyses are around 20% to 30%, although the economic potential was found to be limited to 10% to 15% (Linnhoff-March, 2000). A total-site analysis was performed for a European oil refinery in the late 1990s. The Solomon's EII of the refinery was within the top quartile. The refinery operates 16 processes, including a CDU, VDU, FCC, reformer, coker and hydrotreaters. A study of the opportunities offered by individual process optimization of the CDU, VDU, FCC, coker and two hydrotreaters found a reduction in site EII of 7.5%. A total-site analysis including the cogeneration unit identified a potential reduction of 16% (Linnhoff-March, 2000). Identified opportunities include the conversion of a back-pressure turbine to a condensing turbine, and improved integration of the medium-pressure and low-pressure steam networks. The economically attractive projects would result in savings of approximately 12% to 13%.

Site analyses by chemical producer Solutia identified annual savings of $3.9 million at their Decatur plant, 0.9M$/year at the Anniston site and 3.6 M$/year at the Pensacola site (Dunn and Bush, 2001).

Process integration - Hot rundown. Typically process integration studies focus on the integration of steam flows within processes and between processes. Sometimes it is possible to improve the efficiency by retaining the heat in intermediate process flows from one unit to another unit. This reduces the need for cooling or quenching in one unit and reheating in the other unit. Such an integration of two processes can be achieved through automated process controls linking the process flows between both processes. An assessment of the Equilon refinery in Martinez, California, identified annual savings of $4.3 million (U.S. DOE-OIT, 2002b). However, the assessment results did not include an assessment of investments and payback.

Crude distillation unit (CDU). The CDU processes all the incoming crude, and is therefore a major energy user in all refinery layouts, except for those refineries that receive intermediates by pipeline from other refineries. In fact, it is estimated that the CDU is the largest energy consuming process of all refinery processes (see chapter 4). Energy use and products of the CDU depend on the type of crude processed. New CDUs are supplied by a number of global companies such as ABB Lummus, Kellog Brown & Root, Shell Global Solutions, Stone & Webster, Technip/Elf, and UOP. An overview of available process designs is published as Hydrocarbon Processing's Refining Processes (HCP, 2011).

Process integration is especially important in the CDU, as it is a large energy consumer processing all incoming crude oil. Older process integration studies show reductions in fuel use between 10 and 19% for the CDU (Sunden, 1988; Lee, 1989), with payback periods less than 2 years. Integration of the CDU and VDU can lead to fuel savings of 10% to 20% (Petrick and Pellegrino, 1999) compared to non-integrated units with relatively short paybacks. The actual payback period will depend heavily on the layout of the refinery, needed changes in the heat exchanger network, and fuel prices.

The CDU at BP's Kwinana, Australia refinery was already performing well with limited opportunities for further economic process integration. An analysis of the CDU identified a significant potential for reduction with a payback of around 6 years. However, integration with the residue cracking unit offered significant opportunities to reduce the combined heating demand by 35% to 40% with a simple payback period of 1.6 years (Querzoli, 2002).

Fluid catalytic cracker (FCC). The FCC is a considerable energy consumer in a modern refiner. In this report the FCC energy use is estimated at 5% of total energy use. Depending on the design and product mix of a particular refinery, FCC energy use can be higher than 5%. There are a large number of FCC designs in use, and many were originally built in the 1970s. Today, more energy-efficient designs are being marketed by a number of suppliers. The designs vary in reactor design, type of catalyst used and degree of heat integration. An overview of available process designs is published in Hydrocarbon Processing's Refining Processes (HCP, 2011). The major suppliers are ABB Lummus, Kellog Brown & Root, Shell Global Solutions, Stone & Webster, and UOP. The optimal design will be based on the type of feed processed and the desired product mix and quality. When selecting a new FCC process, energy efficiency should be an integral part of the selection process.

In existing FCC units, energy efficiency can be improved by increasing heat integration and recovery, process flow scheme changes, and power recovery. A FCC has a multitude of flows that need to be heated (sink) and cooled (source). The better the integration of the heat sinks and sources, the lower the energy consumption of an FCC will be. Older FCC designs often do not have an optimized heat exchange setup, which may lead to wasted low-temperature heat that could be used to preheat boiler feed water or cold feed. By better integrating the sources and sinks through the principles of pinch technology (see above), improving combinations of temperature levels and heating/cooling loads may lower energy use. Various authors have reported on the application of pinch analysis and process optimization of FCCs (Hall et al., 1995; Golden and Fulton, 2000). The appropriate combination will depend on the feed processed and output produced. Furthermore, economics for the installation of heat exchangers may determine the need for less efficient combinations.

Al-Riyami et al. (2001) studied the opportunities for process integration of a FCC unit in a refinery in Romania. The FCC unit was originally built by UOP and is used to convert vacuum gas oil and atmospheric gas oil. Several design options were identified to reduce utility consumption. The study of the FCC identified a reduction in utilities of 27% at a payback of 19 months. However, the calculation for the payback period only includes the heat exchangers, and, depending on the design of the FCC and layout of the plant, the payback period may be longer for other plant designs.

A site analysis of energy efficiency opportunities was conducted at a refinery in the United Kingdom. The assessment identified additional opportunities for heat recovery in the FCC by installing a waste heat boiler before the electrostatic precipitator, resulting in savings of $210,000/year at a payback of 2 years (Venkatesan and Iordanova, 2003).

Fluid catalytic cracker - Process flow changes. The product quality demands and feeds of FCCs may change over time. The process design should remain optimized for this change. Increasing or altering the number of pumparounds can improve energy efficiency of the FCC, as it permits increased heat recovery (Golden and Fulton, 2000). A change in pumparounds may affect the potential combinations of heat sinks and sources.

New design and operational tools enable the optimization of FCC operating conditions to enhance product yields. Petrick and Pellegrino (1999) cite studies that have shown that optimization of the FCC-unit, with appropriate modifications of equipment and operating conditions, can increase the yield of high-octane gasoline and alkylate from 3% to 7% per barrel of crude oil, resulting in energy savings.

Reformer. A site analysis of energy efficiency opportunities was conducted at a refinery in the United Kingdom. The assessment identified opportunities to improve the performance of the economizer in the waste heat boilers of two reformer furnaces. The changes would result in annual savings of $140,000 in each reformer at a payback period of 2 years (Venkatesan and Iordanova, 2003).

Coker. A 1999 simulation and optimization of a coker of Jinling Petrochemical Corp.'s Nanjing, China refinery identified a more efficient way to integrate the heat flows in the process. By changing the diesel pumparound, energy cost reduction of $100,000/year was achieved (Zhang, 2001). Unfortunately, there is insufficient data to estimate the savings for U.S. refineries or to evaluate the economics of this project under U.S. conditions.

10. Process Heaters

Between 60% and 70% of all fuel consumed in the refineries is used in furnaces. The average thermal efficiency of furnaces is estimated at 75% to 90% (Petrick and Pellegrino, 1999). Accounting for unavoidable heat losses and dew point considerations, the theoretical maximum furnace efficiency is around 92% (HHV) (Petrick and Pellegrino, 1999). This suggests that, on average, a 10% improvement in energy efficiency can be achieved in furnace and burner design.

The efficiency of heaters can be improved by improving heat transfer characteristics, enhancing flame luminosity, installing recuperators or air preheaters and improved controls. New burner designs improve fuel and air mixing and more efficiently transfer heat. Several technologies have been developed to achieve these goals, including lean-premix burners (Seebold et al., 2001), swirl burners (Cheng, 1999), pulsating burners (Petrick and Pellegrino, 1999) and rotary burners (U.S. DOE-OIT, 2002c). At the same time, furnace and burner design have to address safety and environmental concerns. The most notable is the reduction of NOx emissions. Improved NOx control will be necessary in almost all refineries to meet air quality standards, especially as many refineries are located in non-attainment areas.

10.1 Maintenance

Regular maintenance of burners, draft control and heat exchangers is essential to maintain safe and energy-efficient operation of a process heater.

Draft control. Poorly maintained process heaters may use excess air, reducing the efficiency of the burners. Excess air should be limited to 2% to 3% oxygen to ensure complete combustion. Draft control is applicable to both new and existing heaters and is cost-effective for process heaters of 20 to 30 MMBtu/hr or greater (U.S. EPA, 2010).

Valero's Houston refinery has installed new control systems to reduce excess combustion air at two of the three furnaces of the CDU. The CO control system allows running the furnace with 1% excess oxygen instead of the regular 3% to 4%. The system has not only reduced energy use by 3% to 6%, but also reduced NOx emissions by 10% to 25%, while enhancing the safety of the heater (Valero, 2003). The energy efficiency improvements resulted in an estimated cost savings of $340,000.

A plant-wide assessment of Valero's Houston refinery in 2005 identified additional savings by upgrading additional process heaters with CO control systems. The reduction of excess oxygen from 3.5% to 1.5% will result in energy savings of 77,406 MMBtu/year and cost savings of $247,700/year. Payback period of this specific case will be 1.6 years (U.S. DOE-OIT, 2005). Similar control systems were planned to be introduced in 94 process heaters at the Valero refineries, which would result in total savings of $8.8 million/year (Valero, 2003).

An assessment, co-funded by the U.S. Department of Energy, of the Equilon refinery (now owned by Shell) in Martinez, California found that reduction of excess combustion and draft air would result in annual savings of almost $12 million (U.S. DOE-OIT, 2002b). A similar assessment of the Flying J Refinery at North Salt Lake, Utah (now owned by Big West Oil) found savings of

$100,000/year through oxygen control of the flue gases to control the air intake of the furnaces (Brueske et al., 2002).

An assessment of the Paramount Petroleum Corp.'s asphalt refinery in Paramount (California) identified excess draft air in six process heaters. Regular maintenance (twice per year) can reduce the excess draft air and would result in annual savings of over $290,000 (or nearly 100,000 MMBtu/year). The measure has a simple payback period of 2 months (U.S. DOE-OIT, 2003).

An assessment of the process heaters at the Marathon Petroleum refinery in Robinson (Illinois) has shown that the three heaters assessed have average oxygen concentrations of about 4%, corresponding to approximately 20% to 25% excess air. The average oxygen concentration can be reduced to approximately 2.5%, saving in total $365,000 per year (Marathon Petroleum, 2007).

10.2 Air preheating

Air preheating is an efficient way of improving the efficiency and increasing the capacity of a process heater. The flue gases of the furnace are used to preheat the combustion air. Every 35°F drop in the exit flue gas temperature increases the thermal efficiency of the furnace by 1% (Garg, 1998). Typical fuel savings range between 8 and 18%, and are typically economically attractive if the flue gas temperature is higher than 650°F and the heater size is 50 MMBtu/hr or more (Garg, 1998). Air preheat will increase heater efficiency from 82% to 92% in smaller heaters with older designs (Glasgow et al., 2010). The optimum flue gas temperature is also determined by the sulfur content of the flue gases to reduce corrosion. When adding a preheater, the burner needs to be rerated for optimum efficiency. The typical payback period for combustion air preheating in a refinery is estimated at 2.5 years; however, the costs may vary significantly depending on the layout of the refinery and furnace construction.

An assessment of the process heaters at the Marathon Petroleum refinery in Robinson, Illinois identified annual energy savings of $2.1 million by installing air preheating on two of the three heaters assessed (Marathon Petroleum, 2007). However, the economics of the project prohibited actual realization of the savings.

At a refinery in the United Kingdom, a site analysis of energy efficiency opportunities was conducted. The refinery operated three VDUs, one of which still used natural draught and had no heat recovery installed. By installing a combustion air preheater, using the hot flue gas, and an additional FD fan, the temperature of the flue gas was reduced to 470°F. This led to energy cost savings of $109,000/year with a payback period of 2.2 years (Venkatesan and Iordanova, 2003).

10.3 New burners

In many areas new air quality regulation will require refineries to reduce NOx and VOC emissions from furnaces and boilers. New burner technology may be installed in place of expensive selective catalytic reduction (SCR) flue-gas treatment plants to dramatically reduce emissions. This will result in cost savings as well as a decrease in electricity costs for the SCR.

Chevron, in collaboration with John Zink Co., developed new low-NOx burners for refinery applications based on the lean-premix concept. The burners help to reduce NOx emissions from

180 ppm to below 20 ppm. The burners have been installed in a CDU, VDU and a reformer at Chevron's Richmond, California refinery without taking the furnace out of production, where the burner was applied to retrofit a steam boiler. The installation of the burners in a reforming furnace reduced emissions by over 90%, while eliminating the need for a SCR. This saved the refinery $10 million in capital costs and $1.5 million in annual operating costs of the SCR (Seebold et al., 2001). The operating costs include the reduced electricity costs for operating compressors and fans for the SCR. The operators had to be retrained to operate the new burners, as some of the operation characteristics had changed.

11. Distillation

Distillation is one of the most energy intensive operations in the petroleum refinery. Distillation is used throughout the refinery to separate process products, either from the CDU/VDU or from conversion processes. The incoming flow is heated, after which the products are separated on the basis of boiling points. Heat is provided by process heaters (see Chapter 10) and/or by steam (see Chapter 9). Energy efficiency opportunities exist within the heating process and through optimization of the distillation column.

Optimize operation procedures. Optimizing the reflux ratio of the distillation column can produce significant energy savings. The efficiency of a distillation column is determined by the characteristics of the feed. If the characteristics of the feed have changed over time as compared to the design conditions, operational efficiency can be improved. If operational conditions have changed, calculations to derive new optimal operational procedures should be performed. The design reflux should be compared with the actual ratios controlled by each shift operator. Steam and/or fuel intensity can be compared to the reflux ratio, product purity, etc. and compared with calculated and design performance on a daily basis to improve the efficiency.

Optimize product purity. Many companies tend to excessively purify products, sometimes with good reason. However, purifying to 98% when 95% is acceptable is not necessary. In this case, the reflux rate should be decreased in small increments until the desired purity is obtained. This will decrease the reboiler duties while requiring no or very low investments (Saxena, 1997).

Seasonal operating pressure adjustments. For plants that are in locations that experience winter climates, the operating pressure can be reduced according to a decrease in cooling water temperatures (Saxena, 1997). However, this may not apply to the VDU or other separation processes operating under vacuum. These operational changes will generally not require any investment.

Reduce reboiler duty. Reboilers consume a large part of total refinery energy use as part of the distillation process. By using chilled water, the reboiler duty can, in principal, be lowered by reducing the overhead condenser temperature. A study of using chilled water in a 100,000 bbl/day CDU has led to an estimated fuel saving of 12.2 MMBtu/hr for a 5% increase in cooling duty (2.5 MMBtu/hr) (Petrick and Pellegrino, 1999), assuming the use of chilled water with a temperature of 50°F. The payback period was estimated at 1 to 2 years; however, this excludes the investments to change the tray design in the distillation tower. This technology is not yet proven in a commercial application. This technology can also be applied in other distillation processes.

Upgrade column internals. Damaged or worn internals can result in increased operation costs. As the internals become damaged, efficiency decreases and pressure drops rise. This causes the column to run at a higher reflux rate over time, driving up the reflux rate and energy costs. Replacing the trays with new ones or adding a high performance packing can substantially improve the column operating performance. If operating conditions have seriously deviated from designed operating conditions, the investment may have a relatively short payback.

New tray designs are marketed and developed for many different applications. When replacing the trays, it will often be worthwhile to consider new efficient tray designs. New tray designs can result in enhanced separation efficiency, decreased pressure drop, and reduced energy consumption. When considering new tray designs, the number of trays should be optimized.

Stripper optimization. Steam is injected into the process stream in strippers. Steam strippers are used in various processes, with the CDU being a particularly large user. Both strip steam temperature and use may be too high. Optimization of these parameters can reduce energy use considerably. This optimization can be part of a process integration (or pinch) analysis for the particular unit (see Section 9.2).

Advanced process control

Distillation columns are a classical application of advanced process control (APC) and even though APC has been applied to already many distillation units, additional energy savings can be achieved as the focus is generally on achieving product specifications and shifting product yields toward more valuable products. APC can improve column operations as it continuously predicts control and constraint variables and makes adjustments every minute to keep the system optimized. For many existing distillation columns, applications of APC in a quick revamp could result in significant energy savings (Kesseler, 2010).

An APC project was recently completed at LyondellBasell's Corpus Christi Olefins Complex in Corpus Christi (Texas) to optimize the dilution-steam header pressure. This is a relatively easy, low- to zero-cost option to reduce energy consumption. Manual pressure minimization has demonstrated some limited success. Automation of pressure minimization, in contrast, resulted in optimizing the process and capturing benefits most of the time, something that was not possible manually. Overall, the dilution-steam header pressure was reduced from 110 psig to 102 psig. The project cost and implementation time were minimal and benefits of 73,000 MMBtu/year and net savings of approximately $300,000 per year were realized (Chang and Viducic, 2010).

Progressive crude distillation. Technip and Elf in France developed an energy-efficient design for a crude distillation unit, by redesigning the crude preheater and the distillation column. In the conventional process, all the crude feed is heated to a high temperature prior to entering the distillation tower. In this way, some lighter components of the crude feed are superheated, resulting in energy loss. In the progressive crude distillation design, the crude preheat train is separated in several steps to recover fractions at different temperatures. The distillation tower is re-designed to work at low pressure and changing the outputs to link to the other processes in the refinery and product mix of the refinery. The design results in reduced fuel consumption and better heat integration (reducing the net steam production of the CDU). Technip claims up to a 35% reduction in fuel use when compared to a conventional CDU (Technip, 2000). The estimated capital cost of a new progressive distillation crude unit ranges from $750 to $950/bpd of capacity (2000$) (Haddad and Manley, 2008).

This technology has been applied in the new refinery constructed at Leuna (Germany) in 1997. Because of the changes in CDU-output and needed changes in intermediate flows, progressive crude distillation is especially suited for new construction or large crude distillation expansion projects.

Dividing-wall column. The concept of dividing-wall columns (DWC) originates from 1949, but the first commercial application of the dividing-wall column dates back to the early 1990's (Hallale, 2001). A dividing-wall column integrates two conventional distillation columns into one. This design increases heat transfer and can save up to 30% in energy costs, while providing lower capital costs compared to conventional columns (Schultz et al., 2002). Various companies, including Kellog Brown & Root, Krupp Uhde, Linde, Sumitomo, and UOP, have developed DWC-concepts for the separation of products. BASF in Germany pioneered the DWC and operates the largest number of columns in their chemical plants. In petroleum refining Valero in the United States, BP in the United Kingdom, Chevron in Saudi Arabia, Veba Oel in Germany, and Sasol in South Africa operate dividing-wall columns. Current applications are limited to benzene removal from gasoline or the separation of lighter fractions in gasoline production. Further development of DWC for the major distillation processes in the petroleum refining industry is necessary.

Valero started up three dividing wall columns in their Port Arthur, Sunray, and Memphis refineries in 2010 to produce benzene concentrate from reformate. A fourth unit at their St. Charles refinery was planned to start up later in 2011. The commissioning of these dividing-wall columns would avoid building a costly new benzene extraction plant in order to comply with new U.S. EPA regulation (2011) that requires the annual average benzene content of gasoline to be reduced from 1 vol.% to 0.62 vol.% (Parkinson, 2011).

In 2005, ExxonMobil installed a dividing-wall column in their Fawley refinery in the United Kingdom. At this refinery, dividing-wall column technology is deployed for the revamp of the xylenes column which recovers mixed xylenes from reformate motor gasoline. Energy savings of up to 53% have been achieved together with improvements in xylenes purity (Slade et al., 2006).

Liquid–ring vacuum pump. Vacuum conditions in the vacuum distillation unit are generally maintained by the use of steam ejectors, vacuum pumps and condensers. Replacing the last stage steam ejector in a three-stage ejector system with a liquid-ring vacuum pump (LRVP), referred to as a hybrid system, lowers steam consumption (Glasgow et al., 2010),

A plant-wide assessment at the Valero Houston, Texas refinery resulted in a recommendation to install a liquid ring vacuum compressor to replace the third-stage vacuum steam jets and water cooler in the vacuum tower overhead system. This measure is projected to reduce steam use by 6,000 lb/hr, resulting in annual savings of 95,600 MMBtu and $306,000 per year. With expected capital costs of $450,000, the payback period is 1.5 years (U.S. DOE-OIT, 2005).

12. Hydrogen Management and Recovery

Hydrogen is used in the refinery in processes such as hydrocrackers and desulfurization using hydrotreaters. The production of hydrogen is an energy intensive process using naphtha reformers and natural gas-fueled reformers. These processes and other processes also generate gas streams that may contain a certain amount of hydrogen not used in the processes, or generated as by-product of distillation of conversion processes. In addition, different processes have varying quality (purity) demands for hydrogen feed. Reducing the need for hydrogen make-up will reduce energy use in the reformer and reduce the need for purchased natural gas. The major technology developments in the hydrogen management within the refinery are hydrogen process integration (or hydrogen cascading) and hydrogen recovery technology (Zagoria and Huycke, 2003). Revamping and retrofitting existing hydrogen networks can increase hydrogen capacity between 3% and 30% (Ratan and Vales, 2002).

12.1 Hydrogen integration

Hydrogen network integration and optimization at refineries is an important application of pinch analysis (see above). Most hydrogen systems in refineries feature limited integration, and pure hydrogen flows are sent from the reformers to the different processes in the refinery. As the use of hydrogen increases, especially in Californian refineries, the value of hydrogen appreciates. Using the composition curves approach described in pinch analysis, the production and uses of hydrogen in a refinery can be made visible. This allows individuals to identify the best matches between different hydrogen sources and uses based on the quality of the hydrogen streams. It also enables users to select the most appropriate and cost-effective technology for hydrogen purification. The analysis method accounts for gas pressure, costs of piping, besides the costs for generation, fuel use, and compression power needs. Improvements in this method can reduce compression needs and improve both new and retrofit studies (Hallale, 2001).

The BP refinery in Carson, California, in cooperation with the California Energy Commission, has executed a hydrogen pinch analysis of this large refinery. Total potential savings of $4.5 million on operating costs were identified, but the refinery decided to realize a more cost-effective package, saving $3.9 million per year. As part of the plant-wide assessment of the Equilon (Shell) refinery at Martinez, an analysis of the hydrogen network has been included (U.S. DOE-OIT, 2002b). This resulted in the identification of large energy savings. Further development and application of the analysis method at Californian refineries, especially as the need for hydrogen rises due to the reduced future sulfur content of diesel and other fuels, may result in reduced energy needs at all refineries with hydrogen needs (Khorram and Swaty, 2002). One refinery identified hydrogen savings amounting to $6 million/year without capital projects (Zagoria and Huycke, 2003).

12.2 Hydrogen recovery

Hydrogen recovery is an important technology development area to improve the efficiency of hydrogen recovery, reduce the costs of hydrogen recovery, and increase the purity of the resulting hydrogen flow. Hydrogen can be recovered indirectly by routing low-purity hydrogen streams to the hydrogen plant (Zagoria and Huycke, 2003). Hydrogen can also be recovered from off-gases by routing it to the existing purifier of the hydrogen plant, or by installing additional purifiers to treat the off-gases and vent-gases. Suitable gas streams for hydrogen recovery are the off-gases from the hydrocracker, hydrotreater, coker, and FCC. In addition to hydrogen content, suitability is determined by the pressure, contaminants (i.e., low on sulfur, chlorine and olefins), and tail end components (C_5+) (Ratan and Vales, 2002). The characteristics of the source stream will also impact the choice of recovery technology. The cost savings of recovered hydrogen are around 50% of the costs of hydrogen production (Zagoria and Huycke, 2003).

Hydrogen can be recovered using various technologies, of which the most common are pressure swing and thermal swing absorption, cryogenic distillation and membranes. The choice of separation technology is driven by the desired purity, degree of recovery, pressure and temperature. Various manufacturers supply different types of hydrogen recovery technologies, including Air Products, Air Liquide, Linde, and UOP. Membrane technology generally represents the lowest cost option for low product rates, but not necessarily for high flow rates (Zagoria and Hucyke, 2003). For high-flow rates, pressure swing absorption (PSA) technology is often the conventional technology of choice. PSA is the common technology to separate hydrogen from the reformer product gas. Hundreds of PSA units are used around the world to recover hydrogen from various gas streams. Current developments in the field of PSA are towards rapid-cycle pressure swing adsorption (RCPSA) technology. This technology makes use of a structured absorbent and rotary valves that would boost cycle speed by two orders of magnitude relative to the conventional PSA. It requires significantly smaller (>10 times) absorber vessel sizes and costs are reported to be lower (Saavedra, 2006; Hilbert and Oliveri, 2010). The RCPSA technology has been tested in an ExxonMobil refinery in France, where it was successfully commercialized in 2007.

Cryogenic units are favored, as both hydrogen and other gases, such as LPG, can be recovered from the gas stream as well. Cryogenic units produce a medium purity hydrogen gas steam (up to 96%).

Membranes are an attractive technology for hydrogen recovery in the refinery. If the content of recoverable products is higher than 2% to 5% (or even 10%), recovery may make economic sense (Baker et al., 2000). New membrane applications for the refinery and chemical industries are under development. Membranes for hydrogen recovery from ammonia plants were first demonstrated around 20 years ago (Baker et al., 2000), and are used in various state-of-the-art plant designs. Refinery off-gas flows have a different composition, making different membranes necessary for optimal recovery. Membrane plants have been demonstrated for recovery of hydrogen from hydrocracker off-gases. Various suppliers offer membrane technologies for hydrogen recovery in the refining industry, including Air Liquide, Air Products and UOP. Air Liquide and UOP have sold over 120 membrane hydrogen recovery units around the world. Development of low-cost and efficient membranes is an area of research interest to improve cost-effectiveness of hydrogen recovery and enable recovery from gas streams with lower concentrations.

At a refinery at Ponca City, Oklahoma (currently owned by ConocoPhilips), a membrane system was installed to recover hydrogen from the waste stream of the hydrotreater, although energy savings were not quantified (Shaver et al., 1991). Another early study quotes a 6% reduction in hydrogen makeup after installing a membrane hydrogen recovery unit at a hydrocracker (Glazer et al., 1988). A refinery in Texas installed a membrane system to recover LPG and hydrogen from excess fuel gas. The unit is designed to recover 1,400 barrels/day of LPG and 100,000 scfh of hydrogen. The payback period of this membrane system is less than 1 year (MTR, 2011).

In refineries that recover hydrogen from off-gas streams, the high hydrogen gas stream is typically flared when the recovery compressor fails or is taken offline for maintenance. A back-up recovery compressor could be installed to avoid flaring this high-hydrogen stream. This directly impacts the net quantity of new hydrogen that has to be produced for the refinery. At a refinery in Texas, the replacement of the hydrogen gas stream recovery compressor took 6 months. During this period, about 7,000 tonnes of hydrogen was flared. A back-up recovery compressor would have prevented this hydrogen loss (U.S. EPA, 2010).

12.3 Hydrogen production

Reformer – Adiabatic pre-reformer. If there is excess steam available at a plant, a pre-reformer can be installed at the reformer. Adiabatic steam reforming uses a highly active nickel catalyst to reform a desulfurized hydrocarbon feed, using waste heat (900°F) from the convection section of the reformer. Installing a pre-reformer at an existing plant will typically increase production by 10-20% (Abrardo and Khurana, 1995; Munch et al., 2007).

The Kemira Oy ammonia plant in Rozenburg, the Netherlands, implemented an adiabatic pre-reformer. Energy savings equaled about 4% of the energy consumption with a payback period between 1 and 3 years (Worrell and Blok, 1994). Chevron included a pre-reformer in the design of the new hydrogen plant for its El Segundo, California refinery. The technology can also be used to increase the production capacity at no additional energy cost, or to increase the feed flexibility of the reformer. This is especially attractive if a refinery faces increased hydrogen demand to meet rising desulfurization needs, or switches to heavier crudes. Various suppliers provide pre-reformers, including Haldor-Topsoe, Süd-Chemie, and Technip-KTI.

Reformer - Combustion air and feed preheat. A heat recovery system can be used to preheat the feed and combustion air of the reformer. An increase in the combustion air and feed temperature through the convection section of the reformer can reduce fuel consumption by 42% and steam export by 36%. Total energy savings are about 5% compared to a typical steam methane reformer (U.S. EPA, 2010).

In 2005, Air Liquide America contracted CB&I to provide a 100 million scfd hydrogen production facility with a combustion air preheat design at their Bayport, Texas complex (HCP, 2005).

Gasification of heavy bottom fraction. The heavy bottom fraction of the refinery can be gasified to produce a mixture of carbon monoxide and hydrogen. Gasification can be combined with power production in an integrated gasification combined cycle (IGCC), producing both hydrogen and power. The application of this process in petroleum refining is presented in the power generation section of this Guide (see chapter 18).

13. Motor Systems

Electric motors represent over 80% of all electricity use in a refinery, although electricity is only a relatively small proportion of the total energy consumed in a refinery. The primary applications are pumps (60% of all motor use), air compressors (15%), fans (9%) and other applications (16%). This chapter presents a number of energy efficiency measures available for motors in industrial applications.[11] Additional measures that are specific to pumps, fans, and compressed air systems are offered in later chapters of this Guide.

When considering energy efficiency improvements to a facility's motor systems, it is important to take a "systems approach". A systems approach strives to optimize the energy efficiency of entire motor systems (i.e., motors, drives, driven equipment such as pumps, fans, and compressors, and controls), not just the energy efficiency of motors as individual components. A systems approach analyzes both the energy supply and energy demand sides of motor systems, as well as how these sides interact to optimize total system performance, which includes not only energy use but also system uptime and productivity.

A systems approach typically involves first locating and identifying all of the applications of motors in a facility. Second, the conditions and specifications of each motor should be documented to provide a current systems inventory. Third, the needs and the actual use of the motor systems should be assessed to determine whether or not motors are properly sized and also how well each motor meets the needs of its driven equipment. Fourth, information on potential repairs and upgrades to the motor systems should be collected, including the economic costs and benefits of implementing repairs and upgrades to enable the energy efficiency improvement decision-making process. Finally, if upgrades are pursued, the performance of the upgraded motor systems should be monitored to determine the actual costs savings (SCE, 2003).

The motor system energy efficiency measures below reflect important aspects of this systems approach, including matching motor speeds and loads, proper motor sizing, and upgrading system components.

Motor management plan. A motor management plan is an essential part of a plant's energy management strategy. Having a motor management plan in place can help companies realize long-term motor system energy savings and will ensure that motor failures are handled in a fast and cost effective manner. The Motor Decisions Matter[SM] Campaign suggests the following key elements for a sound motor management plan (MDM, 2012):

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[11] The U.S. DOE's Advanced Manufacturing Office (AMO) provides a variety of resources for improving the efficiency of industrial motor systems, which can be consulted for more detailed information on many of the measures presented in this chapter. For a collection of tips, tools, and industrial case studies on industrial motor system efficiency, visit the Advanced Manufacturing Office's website at: http://www1.eere.energy.gov/manufacturing/tech_deployment/motors.html. The Motor Decisions Matter[SM] Campaign also provides a number of excellent resources for improving motor system efficiency (http://www.motorsmatter.org/).

- Creation of a motor survey and tracking program.
- Development of guidelines for proactive repair/replace decisions.
- Preparation for motor failure by creating a spares inventory.
- Development of a purchasing specification.
- Development of a repair specification.
- Development and implementation of a predictive and preventive maintenance program.

The Motor Decisions Matter^{SM} Campaign's *Motor Planning Kit* contains further details on each of these elements (MDM, 2012).

Strategic motor selection. Several factors are important when selecting a motor, including motor speed, horsepower, enclosure type, temperature rating, efficiency level, and quality of power supply. When selecting and purchasing a motor, it is also critical to consider the life-cycle costs of that motor rather than just its initial purchase and installation costs. Up to 95% of a motor's costs can be attributed to the energy it consumes over its lifetime, while only around 5% of a motor's costs are typically attributed to its purchase, installation, and maintenance (MDM, 2012). Life cycle costing (LCC) is an accounting framework that allows one to calculate the total costs of ownership for different investment options, leading to a more sound evaluation of competing options in motor purchasing and repair or replacement decisions. A specific LCC guide has been developed for pump systems (Hydraulic Institute and Europump, 2001), which also provides an introduction to LCC for motor systems.

The selection of energy-efficient motors can be an important strategy for reducing motor system life-cycle costs. Energy-efficient motors reduce energy losses through improved design, better materials, tighter tolerances, and improved manufacturing techniques. With proper installation, energy-efficient motors can also run cooler (which may help reduce facility heating loads) and have higher service factors, longer bearing life, longer insulation life, and less vibration.

To be considered energy efficient in the United States, a motor must meet performance criteria published by the National Electrical Manufacturers Association (NEMA). The Consortium for Energy Efficiency (CEE) has described the evolution of standards for energy-efficient motors in the United States, which is helpful for understanding "efficient" motor nomenclature (CEE, 2007):

- NEMA Energy Efficient (NEMA EE) was developed in the mid-1980s to define the term "energy efficient" in the marketplace for motors. NEMA Standards Publication No. MG-1-2011, Table 12-11 defines efficiency levels for a range of different motors (NEMA, 2012).
- The Energy Policy Act of 1992 (EPACT) required that many commonly used motors comply with NEMA "energy efficient" ratings if offered for sale in the United States.

- In 1996, the CEE Premium Efficiency Criteria specification was designed to promote motors with higher efficiency levels than EPACT required, for the same classes of motors covered by EPACT. The CEE efficiency levels specified were generally two NEMA efficiency bands (Table 12-10 in NEMA MG-1-2011) above those required by EPACT.

- In 2001, the NEMA Premium® Efficiency Electric Motor specification was developed to address confusion with respect to what constituted the most efficient motors available in the market. This specification was developed by NEMA, CEE, and other stakeholders, and was adapted from the CEE 1996 criteria. It currently serves as the benchmark for premium energy-efficient motors. NEMA Premium® also denotes a brand name for motors which meet this specification. Specifically, this specification covers motors with the following attributes:

    - Speed: 2, 4, and 6 pole
    - Size: 1-500 horsepower (hp)
    - Design: NEMA A and B
    - Enclosure type: open and closed
    - Voltage: low and medium voltage
    - Class: general, definite, and special purpose

The choice of installing a premium efficiency motor strongly depends on motor operating conditions and the life cycle costs associated with the investment. In general, premium efficiency motors are most economically attractive when replacing motors with operation exceeding 2,000 hours/year. However, software tools such as MotorMaster+ (see Appendix F) can help identify attractive applications for premium efficiency motors based on the specific conditions at a given plant.

Sometimes, simply replacing an operating motor with a premium efficiency model may have a low payback period. According to data from the Copper Development Association, the upgrade to high-efficiency motors, as compared to motors that achieve the minimum efficiency as specified by EPACT, can have paybacks of less than 15 months for 50 hp motors (CDA, 2001). Payback times will vary based on size, load factor, running time, local energy costs, and available rebates and/or incentives. Given the quick payback time, it usually makes sense to buy the most efficient motor available (U.S. DOE and CAC, 2003).

NEMA and other organizations have created the Motor Decisions Matter℠ campaign to help industrial and commercial customers evaluate their motor repair and replacement options, promote cost-effective applications of NEMA Premium® motors and “best practice” repair, and support the development of motor management plans before motors fail.

In some cases, it may be cost-effective to rewind an existing energy-efficient motor, instead of purchasing a new motor. As a rule of thumb, when rewinding costs exceed 60% of the costs of a new motor, purchasing the new motor may be a better choice (MDM, 2012). When rewinding a motor, it is important to choose a motor service center that follows best practice motor rewinding standards in order to minimize potential efficiency losses. An ANSI-approved recommended best practice standard has been offered by the Electric Apparatus Service Association (EASA) for the repair and rewinding of motors (EASA, 2006). When best rewinding practices are implemented, efficiency losses are typically less than 0.5% to 1%. However, poor quality rewinds may result in larger efficiency losses. It is therefore important to inquire whether the motor service center follows EASA best practice standards (EASA, 2006).

Maintenance. The purposes of motor maintenance are to prolong motor life and to foresee a motor failure. Motor maintenance measures can be categorized as either preventative or predictive. Preventative measures, the purpose of which is to prevent unexpected downtime of motors, include electrical consideration, voltage imbalance minimization, load consideration, and motor ventilation, alignment, and lubrication. The purpose of predictive motor maintenance is to observe ongoing motor temperature, vibration, and other operating data to identify when it becomes necessary to overhaul or replace a motor before failure occurs (Barnish et al., 1997). The savings associated with an ongoing motor maintenance program are significant, and could range from 2% to 30% of total motor system energy use (Efficiency Partnership, 2004).

Properly sized motors. Motors that are sized inappropriately result in unnecessary energy losses. Where peak loads on driven equipment can be reduced, motor size can also be reduced. Replacing oversized motors with properly sized motors saves, on average for U.S. industry, 1.2% of total motor system electricity consumption (U.S. DOE-OIT, 2002d). Higher savings can often be realized for smaller motors and individual motor systems.

To determine the proper motor size, the following data are needed: load on the motor, operating efficiency of the motor at that load point, the full-load speed of the motor to be replaced, and the full-load speed of the replacement motor. The U.S. DOE's BestPractices program provides a fact sheet that can assist in decisions regarding replacement of oversized and under-loaded motors (U.S. DOE-OIT, 1996). Additionally, software packages such as MotorMaster+ (see Appendix F) can aid in proper motor selection.

Adjustable speed drives (ASDs).[12] Adjustable-speed drives better match speed to load requirements for motor operations, and therefore ensure that motor energy use is optimized to a given application. Adjustable-speed drive systems are offered by many suppliers and are available worldwide. The installation of ASDs improves overall productivity, control and product quality, and reduces wear on equipment, thereby reducing future maintenance costs. Worrell et al. (1997) provide an overview of savings achieved with ASDs in a wide array of applications; typical energy savings are shown to vary between 7% and 60%. Industrial case studies from the IAC database

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[12] Several terms are used in practice to describe a motor system that permits a mechanical load to be driven at variable speeds, including adjustable speed drives (ASDs), variable speed drives (VSDs), adjustable frequency drives (AFDs), and variable frequency drives (VFDs). The term ASD is used throughout this Guide for consistency.

suggest that the payback period associated with the installation of ASDs in a number of different applications ranges between roughly one and three years (IAC, 2012).

The Preem Petroleum AB refinery in Gothenburg (Sweden) installed an ASD on the exhaust fan of the catalytic convertor. While this resulted in power savings, the ASD was primarily installed to better control the air flow through the catalytic convertor and ensure proper NOx emission reductions.

Power factor correction. Inductive loads like transformers, electric motors and HID lighting may cause a low power factor. A low power factor may result in increased power consumption, and hence increased electricity costs. The power factor can be corrected by minimizing idling of electric motors (a motor that is turned off consumes no energy), replacing motors with premium-efficient motors (see above), and installing capacitors in the AC circuit to reduce the magnitude of reactive power in the system.

Minimizing voltage unbalances. A voltage unbalance degrades the performance and shortens the life of three-phase motors. A voltage unbalance causes a current unbalance, which will result in torque pulsations, increased vibration and mechanical stress, increased losses, and motor overheating, which can reduce the life of a motor's winding insulation. Voltage unbalances may be caused by faulty operation of power correction equipment, an unbalanced transformer bank, or an open circuit. A rule of thumb is that the voltage unbalance at the motor terminals should not exceed 1%. Even a 1% unbalance will reduce motor efficiency at part load operation, while a 2.5% unbalance will reduce motor efficiency at full load operation.

For a 100 hp motor operating 8,000 hours per year, a correction of the voltage unbalance from 2.5% to 1% will result in electricity savings of 9,500 kWh or almost $500 at an electricity rate of $0.05/kWh (U.S. DOE-OIT, 2005b).

By regularly monitoring the voltages at the motor terminal and through regular thermographic inspections of motors, voltage unbalances may be identified. It is also recommended to verify that single-phase loads are uniformly distributed and to install ground fault indicators as required. Another indicator that a voltage unbalance may be a problem is 120 Hz vibration, which should prompt an immediate check of voltage balance (U.S. DOE-OIT, 2005b). The typical payback period for a voltage controller installation on lightly loaded motors in the United States is 2.6 years (IAC, 2012).

14. Pump Systems

In the petroleum refining industry, roughly 59% of all electricity use in motors is for pumps (Xenergy, 1998). This makes pumps the single largest electricity user in a refinery, consuming 48% of the total electrical energy used in a refinery. Pumps are used throughout the entire plant to generate pressure and move liquids. Studies have shown that 30% to 50% of the energy consumed by these systems could be saved through equipment or control system improvements (Hydraulic Institute and Europump, 2001).

It is important to note that initial costs are only a fraction of the life cycle costs of a pump system. Energy costs, and sometimes operations and maintenance costs, are much more important in the lifetime costs of a pump system. In general, for a pump system with a lifetime of 20 years, the initial capital costs of the pump and motor make up merely 2.5% of the total costs (Best Practice Programme, 1998). Depending on the pump application, energy costs may comprise roughly 95% of the lifetime costs of the pump. Hence, the initial choice of a pump system should be highly dependent on energy cost considerations, rather than on initial costs. Optimization of the design of a new pumping system should focus on optimizing the lifecycle costs. Hodgson and Walters (2002) discuss software developed for this purpose and discuss several case studies in which they show large reductions in energy use and lifetime costs of a complete pumping system. Typically, such an approach will lead to energy savings of 10% to 17%.

Pumping systems consist of a pump, a driver, piping systems, and controls (such as ASDs or throttles). There are two main ways to increase pump system efficiency, aside from reducing use: reducing the friction in dynamic pump systems (not applicable to static or "lifting" systems), or upgrading/adjusting the system so that it draws closer to the best efficiency point (BEP) on the pump curve (Hovstadius, 2002). Correct sizing of pipes, surface coating or polishing, and ASDs, for example, may reduce the friction loss, increasing energy efficiency. Correctly sizing the pump and choosing the most efficient pump for the applicable system will push the system closer to the best efficiency point on the pump curve. Furthermore, pump systems are part of motor systems, and thus the general "systems approach" to energy efficiency described in Chapter 13 for motors applies to pump systems as well.

Many of the most significant energy efficiency measures applicable to pump system components and to pump systems as a whole are described below. [13]

Maintenance. Inadequate maintenance can lower pump system efficiency, cause pumps to wear out more quickly, and increase pumping energy costs. The implementation of a pump system

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[13] The U.S. DOE's Advanced Manufacturing Office provides a variety of resources for improving the efficiency of industrial pumps, which can be consulted for more detailed information on many of the measures presented in this chapter. The U.S. DOE's *Improving Pumping System Performance: A Sourcebook for Industry* is a particularly helpful resource (U.S. DOE-OIT, 2006b). For a collection of tips, tools, and industrial case studies on industrial pump efficiency, visit the U.S. DOE website at: http://www1.eere.energy.gov/manufacturing/tech_deployment/pumps.html.

maintenance program will help to avoid these problems by keeping pumps running optimally. Furthermore, improved pump system maintenance can lead to pump system energy savings of 2% to 7% (U.S. DOE-OIT, 2002d). A solid pump system maintenance program will generally include the following tasks (U.S. DOE-OIT, 2006b; U.S. DOE-OIT, 2002d):

- Replacement of worn impellers, especially in caustic or semi-solid applications.
- Bearing inspection and repair.
- Bearing lubrication replacement, on an annual or semiannual basis.
- Inspection and replacement of packing seals. Allowable leakage from packing seals is usually between two and sixty drops per minute.
- Inspection and replacement of mechanical seals. Allowable leakage is typically one to four drops per minute.
- Wear ring and impeller replacement. Pump efficiency degrades from 1 to 6 percent for impellers less than the maximum diameter and with increased wear ring clearances.
- Checking of pump/motor alignment.
- Inspection of motor condition, including the motor winding insulation.

Monitoring. Monitoring in conjunction with operations and maintenance can be used to detect problems and determine solutions to create a more efficient pump system. Monitoring can determine clearances that need be adjusted, indicate blockage, impeller damage, inadequate suction, operation outside preferences, clogged or gas-filled pumps or pipes, or worn out pumps. Monitoring should include:

- Specific energy consumption, i.e., electricity use/flow rate (Hovstadius, 2007)
- Wear monitoring
- Vibration analyses
- Pressure and flow monitoring
- Current or power monitoring
- Differential head and temperature rise across the pump (also known as thermodynamic monitoring)
- Distribution system inspection for scaling or contaminant build-up

Reduction of pump demand. An important component of the systems approach is to minimize pump demand by better matching pump requirements to end use loads. Two effective strategies for reducing pump demand are the use of holding tanks and the elimination of bypass loops. Holding tanks can be used to equalize pump flows over a production cycle, allowing for more efficient operation of pumps at reduced speed and leading to energy savings of 10% to 20% (U.S. DOE-OIT, 2002d). Other effective strategies for reducing pump demand include lowering process static pressures, minimizing elevation rises in the piping system, and lowering spray nozzle velocities.

Controls. Control systems can increase the energy efficiency of a pump system by shutting off pumps automatically when demand is reduced, or, alternatively, by putting pumps on standby at reduced loads until demand increases.

In 2000, Cisco Systems upgraded the controls on its fountain pumps so that pumps would be turned off automatically during periods of peak electrical system demand. A wireless control system was able to control all pumps simultaneously from one location. The project saved $32,000 and 400,000 kWh annually, representing a 61.5% reduction in the total energy consumption of the fountain pumps (CEC and OIT, 2002). With a total cost of $29,000, the simple payback period was 11 months. In addition to energy savings, the project reduced maintenance costs and increased the pump system's equipment life.

High-efficiency pumps. It has been estimated that up to 16% of pumps in the U.S. industry are more than 20 years old (U.S. DOE-OIT, 2002d). Considering that a pump's efficiency may degrade 10% to 25% over the course of its life, the replacement of aging pumps can lead to significant energy savings. The installation of newer, higher-efficiency pumps typically leads to pump system energy savings of 5% to 25% (de Almeida et al., 2011).

A number of high-efficiency pumps are available for specific pressure head and flow rate capacity requirements. Choosing the right pump often saves both operating and capital costs. For a given duty, selecting a pump that runs at the highest speed suitable for the application will generally result in a more efficient selection as well, as the lowest initial cost (Hydraulic Institute and Europump, 2001).

Properly sized pumps. Pumps that are oversized for a particular application consume more energy than is truly necessary (see "avoiding throttling valves" below). It is estimated that 75% of pump systems are oversized (Hydraulic Institute and Europump, 2004). Replacing oversized pumps with pumps that are properly sized can often reduce the electricity use of a pumping system by 15% to 25% (U.S. DOE-OIT, 2002d). Where peak loads can be reduced through improvements to pump system design or operation (e.g., via the use of holding tanks), pump size can also be reduced. If a pump is dramatically oversized, often its speed can be reduced with gear or belt drives or a slower speed motor. The typical payback period for the above strategies can be less than one year (U.S. DOE-OIT, 2002).

The Chevron refinery in Richmond, California identified two large horsepower secondary pumps at the blending and shipping plant that were inappropriately sized for their intended use, and required throttling while in operation. The 400 hp and 700 hp pump were replaced by two 200 hp pumps equipped with adjustable speed drives. This reduced energy consumption by 4.3 million kWh per year, and resulted in annual savings of $215,000 (CEC and OIT, 2001). With investments of $300,000 the payback period was 1.4 years.

The Welches Point Pump Station, a medium sized waste water treatment plant located in Milford, Connecticut, as a participant in the Department of Energy's Motor Challenge Program, decided to replace one of their system's three identical pumps with a smaller model (Flygt, 2002). They found that the smaller pump could more efficiently handle typical system flows and the remaining two larger pumps could be reserved for peak flows. While the smaller pump needed to run longer to handle the same total volume, its slower pace and reduced pressure resulted in less friction-related losses and less wear and tear. Substituting the smaller pump had a projected saving of 36,096 kW, more than 20% of the pump system's annual electrical energy consumption. Using this system at each of the city's 36 stations would result in energy savings of over $100,000. In addition to the energy savings projected, less wear on the system results in less maintenance, less downtime and longer life of the equipment. The station noise is also significantly reduced with the smaller pump.

Multiple pumps for variable loads. The use of multiple pumps installed in parallel can be a cost-effective and energy-efficient solution for pump systems with variable loads. Parallel pumps offer redundancy and increased reliability, and can often reduce pump system electricity use by 10% to 30% for highly variable loads (U.S. DOE-OIT, 2002d). Parallel pump arrangements often consist of a large pump, which operates during periods of peak demand, and a small pump (or "pony" pump), which operates under normal, more steady-state conditions. Because the pony pump is sized for normal system operation, this configuration operates more efficiently than a system that relies on a large pump to handle loads far below its optimum capacity.

For example, one case study of a Finnish pulp and paper plant indicated that, by installing a pony pump in parallel with an existing larger pump to circulate water from a paper machine into two tanks, electricity costs were reduced by $36,500 per year, with a simple payback period of just 6 months (Hydraulic Institute and Europump, 2001).

Adjustable speed drives (ASDs). ASDs better match speed to load requirements for pumps where, as for motors, energy use is approximately proportional to the cube of the flow rate[14]. Hence, small reductions in flow that are proportional to pump speed may yield large energy savings for friction dominated pump systems. However, in static head dominated systems the energy use might increase when using ASDs if the speed is too low. New installations may result in short payback periods. In addition, the installation of ASDs improves overall productivity, control and product quality, and reduces wear on equipment, thereby reducing future maintenance costs.

According to inventory data collected by Xenergy (1998), 82% of pumps in U.S. industry have no load modulation feature (or ASD). Similar to being able to adjust load in motor systems, including

[14] This equation applies to dynamic systems only. Systems that solely consist of lifting (static head systems) will accrue no benefits from (but will often actually become more inefficient) ASDs because pump efficiency usually drops when speed is reduced in such systems. A careful choice of operating points can, to some extent, overcome this problem. Similarly, systems with more static head will accrue fewer benefits than systems that are largely dynamic (friction) systems. More careful calculations must be performed to determine actual benefits, if any, for these systems.

modulation features with pumps is estimated to save about 25% of pump energy consumption, at relatively short payback periods, depending on application, pump size, load and load variation (de Almeida et al., 2011). The savings depend strongly on the system curve. As a rough rule of thumb, unless the pump curves are exceptionally flat, a 20% reduction of flow can reduce input power requirements by approximately 50% (U.S. DOE-OIT, 2007b).

The Chevron refinery in Richmond, California upgraded the feed pumps of the diesel hydrotreater by installing an ASD on the 2250 hp primary feed pump, as well as changing the operation procedures for a backup pump system. The cost savings amount to $700,000/year reducing electricity consumption by 12 GWh/year. The pump system retrofit was implemented as part of a demand side management program by the local utility. The refinery did not have to put up any investment capital as it participated in this program (U.S. DOE-OIT, 1999).

An energy savings assessment at the Murphy Oil Superior Refinery in Wisconsin (currently owned by Calumet) recommended upgrading five pumps (e.g., raw crude pump, vacuum bottom pump) with a variable frequency drive. This will allow varying flow without excessive throttling and would lower energy consumption in the pump motor. Upgrading these pumps with a variable frequency drive offers potential savings of 2,884,000 kWh and $110,800 per year (Murphy Oil, 2007). This represents a reduction of approximately 2.5% in the plant's electric energy use and energy costs.

At a pumping station in Berisso, Argentina belonging to Repsol's La Plata refinery, frequency controls were installed to better match the variations in the load profile of the volume of petroleum products pumped. This has resulted in power savings of up to 21% and increased reliability (Rockwell Automation, 2006).

At a San Francisco refinery, the installation of variable frequency drives on a product transfer pump and a primary feed pump saved $120,000 and $220,000 per year, respectively. The ASD reduced vibration and eliminated mechanical seal and bearing failures and energy savings were 500,000 kWh per month. The refinery had no investment costs, but savings were shared with the contractor, who provided the capital investments (Hydraulic Institute and Europump, 2004).

Impeller trimming. Impeller trimming refers to the process of reducing an impeller's diameter via machining, which will reduce the energy added by the pump to the system fluid. According to the U.S. DOE-OIT (2006b), one should consider trimming an impeller when any of the following conditions occur:

- Many system bypass valves are open, indicating that excess flow is available to system equipment.
- Excessive throttling is needed to control flow through the system or process.
- High levels of noise or vibration indicate excessive flow.
- A pump is operating far from its design point.

Trimming an impeller is slightly less effective than buying a smaller impeller from the pump manufacturer, but can be useful when an impeller at the next smaller available size would be too small for the given pump load. The energy savings associated with impeller trimming are dependent upon pump power, system flow, and system head, but are roughly proportional to the cube of the diameter reduction (U.S. DOE-OIT, 2006b). An additional benefit of impeller trimming is a decrease in pump operating and maintenance costs. Care has to be taken when an impeller is trimmed or the speed is changed so that the new operating point does not end up in an area where the pump efficiency is low.

In one case study in the chemical processing industry, the impeller was reduced from 320 mm to 280 mm, which reduced the power demand by more than 25% (Hydraulic Institute and Europump, 2001). Annual energy demand was reduced by 83 MWh (26%). With an investment cost of $390 (US), the payback on energy savings alone was 23 days. In addition to energy savings, maintenance costs were reduced, system stability was improved, cavitation reduced, and excessive vibration and noise were eliminated.

In another case study, Salt Union Ltd., the largest salt producer in the UK, trimmed the diameter of a pump impeller at its plant from 320 mm to 280 mm (13 to 11 inches) (Best Practice Programme, 1996). After trimming the impeller, they found significant power reductions of 30%, or 197,000 kWh per year (710 GJ/year), totaling 8,900 GBP ($14,000 1994 US). With an investment cost of 260 GBP ($400 1993 US), and maintenance savings of an additional 3,000 GBP ($4,600 1994 US), this resulted in a payback of 8 days (11 days from energy savings alone). In addition to energy and maintenance savings, like the chemical processing plant, cavitation was reduced and excessive vibration and noise were eliminated. With the large decrease in power consumption, the 110 kW motor could be replaced with a 75kW motor, with additional energy savings of about 16,000 kWh per year.

Avoid throttling valves. Throttling valves should always be avoided. Extensive use of throttling valves or bypass loops may be an indication of an oversized pump (Tutterow et al., 2000). Variable speed drives or on off regulated systems are always more energy efficient than throttling valves (Hovstadius, 2002).

An assessment of the 25,000 bpd Flying J Refinery in Salt Lake City, Utah (currently owned by Big West Oil) identified throttle losses at two 200 hp charge pumps. Minimizing the throttle losses would result in potential energy cost savings of $39,000 (Brueske et al., 2002). The shutdown of a 250 hp pump when not needed and the minimization of throttle losses would result in additional savings of $28,000 per year.

Replacement of belt drives. Most pumps are directly driven. However, inventory data suggests 4% of pumps have V-belt drives (Xenergy, 1998). Standard V-belts tend to stretch, slip, bend and compress, which lead to a loss of efficiency by up to 5% (U.S. DOE-OIT, 2005c). Replacing standard V-belts with cog belts can save energy and money, even as a retrofit. It is even better to replace the pump by a direct driven system, resulting in increased savings of up to 8% and payback periods as short as 6 months (Studebaker, 2007).

Proper pipe sizing. Pipes that are too small for the required flow velocity can significantly increase the amount of energy required for pumping, in much the same way that drinking a beverage through a small straw requires a greater amount of suction. Where possible, pipe diameters can be increased to reduce pumping energy requirements, but the energy savings due to increased pipe diameters must be balanced with increased costs for piping system components. A life-cycle costing approach is recommended to ensure positive economic benefits when energy savings, increased material costs, and installation costs are considered. Increasing pipe diameters will likely only be cost effective during greater pump system retrofit projects. The U.S. Department of Energy estimates typical industrial energy savings in the 5% to 20% range for this measure (U.S. DOE-OIT, 2002d).

Precision castings, surface coatings or polishing. The use of castings, coatings or polishing reduces pump surface roughness that in turn increases and helps to maintain energy efficiency. This measure is more effective on smaller pumps. One case study in the steel industry analyzed the investment in surface coating on the mill supply pumps (350 kW pumps). They determined that the additional cost of coating, $1200, would be paid back in 5 months by energy savings of $2700 (or 36 MWh, 2%) per year (Hydraulic Institute and Europump, 2001). Energy savings for coating pump surfaces are estimated to be 2 to 3% over uncoated pumps (Best Practice Programme, 1998).

Sealings. Seal failure accounts for up to 70% of pump failures in many applications (Hydraulic Institute and Europump, 2001). The sealing arrangements on pumps will contribute to the power absorbed. Often the use of gas barrier seals, balanced seals, and non-contacting labyrinth seals decrease seal losses.

Non-contacting dual unpressurized seals have been in use on centrifugal compressors since the late 1970s and have been adapted for the hydrocarbon processing industry. These seals are ideal for use with hydrocarbon fluids, such as propane, ethane and ethylene, or a mixture of these fluids. As hydrocarbon fluids naturally vaporize under normal atmospheric pressures and temperatures, the use of standard contacting seals require modified seal faces and large quantities of seal flush to avoid vaporization and to keep the seals cool and lubricated. This generally consumes significant quantities of energy and may result in a short seal lifetime. With the use of non-contacting seals for hydrocarbon fluids, the fluid naturally vaporizes and is sealed as a vapor, improving energy efficiency and reliability. A non-contacting dual unpressurized seal has a lifetime of between 8 and 12 years, compared to a life expectancy of a contacting seal of between 6 months and 2 years, thereby reducing maintenance costs and downtime for repair (Goodenberger, 2009).

A petrochemical facility in the UK replaced eight of their traditional soft packing glands in the boiler feed pump with mechanical seals. The average leakage rate from the traditional pumps was about 1 l/min per gland. Energy savings were calculated to be about 1 GWh per year and are purely based on heating requirements and do not include energy costs for water treatment, reaeration, or any pumping (Smith and Booth, 2008).

Curtailing leakage through clearance reduction. Internal leakage losses are a result of differential pressure across the clearance between the impeller suction and pressure sides. The larger the clearance, the greater is the internal leakage causing inefficiencies. The normal clearance in new pumps ranges from 0.35 to 1.0 mm (0.014 to 0.04 in.) (Hydraulic Institute and Europump, 2001). With wider clearances, the leakage increases almost linearly with the clearance. For example, a clearance of 5 mm (0.2 in.) decreases the efficiency by 7 to 15% in closed impellers and by 10 to 22% in semi-open impellers. Abrasive liquids and slurries, including rainwater, can affect the pump efficiency. Using very hard construction materials, such as stainless steel, can reduce the wear rate.

15. Compressors and Compressed Air

Compressors consume approximately 12% of total electricity use in refineries, or an estimated 5,800 GWh. The principal energy uses for compressors within refineries are furnace combustion of air and gas streams. Large compressors can be driven by electric motors, steam turbines or gas turbines. A relatively small proportion of energy consumption by compressors in refineries is used to generate compressed air. Compressed air is probably the most expensive form of energy available in an industrial plant because of its poor efficiency. Typically, the efficiency of a compressed air system from compressed air generation to end use is only around 10% (U.S. DOE and CAC 2003). Given this inefficiency, compressed air should be used in the smallest quantity and for the shortest duration possible; it should also be constantly monitored and weighed against potential alternatives. Additionally, the annual energy cost required to operate compressed air systems is greater than their initial cost.

Many opportunities to reduce energy consumption in compressed air systems are not prohibitively expensive; payback periods for some options can be extremely short. Energy savings from compressed air system improvements can range from 20% to 50% of total system electricity consumption (McKane et al. 1999). A properly managed compressed air system can also reduce maintenance, decrease downtime, increase production throughput, and improve product quality.

Because of its limited use in a refinery, as an inefficient source of energy, the main compressed air measures found in other industries are highlighted below.[15] Additionally, a number of measures that are applicable to motors (chapter 13) are also applicable to compressed air systems.

Implement system improvements. Adding additional compressors should be considered only after a complete system evaluation. In many cases, compressed air systems can be managed and reconfigured to operate more efficiently without purchasing additional compressors. System improvements utilize many of the energy efficiency measures for compressors discussed below. Compressed air system service providers offer integrated services both for system assessments and for ongoing system maintenance needs, alleviating the need to contact several separate firms. The Compressed Air Challenge® (http://www.compressedairchallenge.org) offers extensive training on the systems approach, technical publications, and free web-based guidance for selecting the right integrated service provider. Also provided are guidelines for walk-through evaluations, system assessments, and fully instrumented system assessments (CAC, 2002).

[15] The U.S. DOE's Advanced Manufacturing Office provides a variety of resources for improving the efficiency of industrial compressed air systems, which can be consulted for more detailed information on many of the measures presented in this chapter. The U.S. DOE's *Improving Compressed Air System Performance: A Sourcebook for Industry* is a particularly helpful resource (U.S. DOE, 2003e). For a collection of tips, tools, and industrial case studies on compressed air systems, visit the U.S. DOE Compressed Air website at: http://www1.eere.energy.gov/manufacturing/tech_deployment/compressed_air.html.

Maintenance. Inadequate maintenance can lower compression efficiency and increase air leakage or pressure variability, as well as lead to increased operating temperatures, poor moisture control, and excessive contamination. Improved maintenance will reduce these problems and save energy. Proper maintenance includes the following (U.S. DOE and CAC 2003; Scales and McCulloch 2007):

- *Ongoing filter inspection maintenance.* Blocked filters increase pressure drop across the filter, which wastes system energy. By inspecting and periodically cleaning filters, filter pressure drops may be minimized. Fixing improperly operating filters will also prevent contaminants from entering into equipment, which can cause premature wear. Generally, when pressure drop exceeds 2 to 3 psig, particulate and lubricant removal elements should be replaced. Regular filter cleaning and replacement has been projected to reduce compressed air system energy consumption by around 2% (Radgen and Blaustein, 2001).

- *Keeping compressor motors properly lubricated and cleaned.* Poor motor cooling can increase motor temperature and winding resistance, shortening motor life, and increasing energy consumption. Compressor lubricant should be changed every 2 to 18 months and periodically checked to make sure that it is at the proper level. In addition, proper compressor motor lubrication will reduce corrosion and degradation of the system.

- *Inspection of fans and water pumps for peak performance.*

- *Inspection of drain traps* to ensure they are not stuck in either the open or closed position and are clean. Some users leave automatic condensate traps partially open at all times to allow for constant draining. This practice wastes substantial amounts of energy and should never be undertaken. Instead, simple pressure driven valves should be employed. Malfunctioning traps should be cleaned and repaired instead of left open. Some automatic drains, such as float switch or electronic drains do not waste air and have typical energy savings of 1% to 5% (de Almeida et al., 2011). Inspecting and maintaining drains typically has a payback of less than two years (U.S. DOE-OIT, 2004).

- *Maintain the coolers* on the compressor to ensure that the dryer gets the lowest possible inlet temperature (U.S. DOE and CAC, 2003).

- *Compressor belt inspection.* Where belt-driven compressors are used, belts should be checked regularly for wear and adjusted. A good rule of thumb is to adjust them every 400 hours of operation.

- *Replacing air lubricant separators* according to specifications or sooner. Rotary screw compressors generally start with their air lubricant separators having a 2 psi to 3 psi pressure drop at full load. When the pressure drop increases to 10 psi, the separator should be changed (U.S. DOE and CAC, 2003).

- *Checking water-cooling systems* regularly for water quality (pH and total dissolved solids), flow, and temperature. Water-cooling system filters and heat exchangers should be cleaned and replaced per the manufacturer's specifications.

- *Minimizing compressed air leaks throughout the system.*

- Applications requiring compressed air should be *checked for excessive pressure, duration or volume*. Applications not requiring maximum system pressure should be regulated, either by production line sectioning or by pressure regulators on the equipment itself. Using more pressure than required, wastes energy and can also result in shorter equipment life and higher maintenance costs. Case studies have demonstrated that the payback period for this measure is a few months (IAC, 2012).

Monitoring. In addition to proper maintenance, a continuous monitoring system can save significant energy and operating costs in compressed air systems. Effective monitoring systems typically include the following (CADDET, 1997):

- Pressure gauges on each receiver or main branch line and differential gauges across dryers, filters, etc.

- Temperature gauges across the compressor and its cooling system to detect fouling and blockages.

- Flow meters to measure the quantity of air used.

- Dew point temperature gauges to monitor the effectiveness of air dryers.

- Kilowatt-hour meters and hours run meters on the compressor drive.

- Checking for compressed air distribution systems after equipment has been reconfigured to be sure that no air is flowing to unused equipment or to obsolete parts of the compressed air distribution system.

- Check for flow restrictions of any type in a system, such as an obstruction or roughness, which can unnecessarily raise system operating pressure. As a rule of thumb, every 2 psi pressure rise resulting from resistance to flow can increase compressor energy use by 1% (U.S. DOE and CAC, 2003). The highest pressure drops are usually found at the points of use, including undersized or leaking hoses, tubes, disconnects, filters, regulators, valves, nozzles and lubricators (demand side), as well as air/lubricant separators, after-coolers, moisture separators, dryers and filters.

- Checking for compressed air use outside production hours.

Leak reduction. Air leaks can be a significant source of wasted energy. A typical industrial facility that has not been well maintained will likely have a leak rate ranging from 20% to 30% of total compressed air production capacity (U.S. DOE and CAC, 2003). Overall, a 15% to 20% reduction of annual energy consumption in compressed air systems is projected for fixing leaks (Radgen and Blaustein, 2001; de Almeida et al., 2011). Furthermore, different types of compressors have different propensities to leak. Based on natural gas compressors, reciprocating compressors have generally half of the fugitive emissions of centrifugal compressors (U.S. EPA, 1999). This may be considered in compressor selection.

The magnitude of the energy loss associated with a leak varies with the size of the hole in the pipes or equipment. A compressor operating 2,500 hours per year at 87 psi with a leak diameter of 0.02 inches (½ mm) is estimated to lose 250 kWh per year; 0.04 in. (1 mm) to lose 1,100 kWh per year; 0.08 in. (2 mm) to lose 4,500 kWh per year; and 0.16 in. (4 mm) to lose 11,250 kWh per year (CADDET, 1997).

In addition to increased energy consumption, leaks can make air-powered equipment less efficient, shorten equipment life, and lead to additional maintenance costs and increased unscheduled downtime. Leaks also cause an increase in compressor energy and maintenance costs.

The most common areas for leaks are couplings, hoses, tubes, fittings, pressure regulators, open condensate traps and shut-off valves, pipe joints, disconnects, and thread sealants. The best way to detect leaks is to use an ultrasonic acoustic detector, which can recognize the high frequency hissing sounds associated with air leaks. Leak detection and repair programs should be ongoing efforts.

A retrofit of the compressed air system of a Mobil lubrication plant in Vernon, California led to the replacement of a compressor by a new 50 hp compressor and the repair of air leaks in the system. The annual energy savings amounted to $20,700, and investments were equal to $23,000, leading to a payback period of just over 1 year (U.S. DOE-OIT, 2003).

Turning off unnecessary compressed air. Equipment that is no longer using compressed air should have the air turned off completely. This can be done using a simple solenoid valve. Compressed air distribution systems should be checked when equipment has been reconfigured to ensure that no air is flowing to unused equipment or to obsolete parts of the compressed air distribution system. Energy savings of improving end-use efficiency vary between 3% and 12% (de Almeida et al., 2011).

Modification of system in lieu of increased pressure. For individual applications that require a higher pressure, instead of raising the operating pressure of the whole system, special equipment modifications should be considered, such as employing a booster, increasing a cylinder bore, changing gear ratios, or shifting operation to off peak hours.

Replacement of compressed air by alternative sources. Many operations can be accomplished more economically and efficiently using energy sources other than compressed air (U.S. DOE-OIT, 2004b, 2004c). Various options exist to replace compressed air use, including:

- Cooling electrical cabinets: air conditioning fans should be used instead of using compressed air vortex tubes.

- Flowing high-pressure air past an orifice to create a vacuum: a vacuum pump system should be applied instead of compressed air venture methods.

- Cooling, aspirating, agitating, mixing, or package inflating: blowers should be used instead of compressed air.

- Cleaning parts or removing debris: brushes, blowers, or vacuum pump systems should be used instead of compressed air.

- Moving parts: blowers, electric actuators, or hydraulics should be used instead of compressed air.

- Tools or actuators: electric motors should be considered because they are more efficient than using compressed air (Howe and Scales, 1995). However, it has been reported that motors can have less precision, shorter lives, and lack safety compared to compressed air. In these cases, using compressed air may be a better choice.

Improved load management. Because of the large amount of energy consumed by compressors, whether in full operation or not, partial load operation should be avoided. For example, unloaded rotary screw compressors still consume 15% to 35% of full-load power while delivering no useful work (U.S. DOE and CAC, 2003).

Air receivers can be employed near high demand areas to provide a supply buffer to meet short-term demand spikes that can exceed normal compressor capacity. In this way, the number of required online compressors may be reduced. Multi-stage compressors theoretically operate more efficiently than single-stage compressors. Multi-stage compressors save energy by cooling the air between stages, reducing the volume and work required to compress the air. Replacing single-stage compressors with two-stage compressors typically provides a payback period of two years or less (Ingersoll-Rand, 2001). Using multiple smaller compressors instead of one large compressor can save energy as well. Large compressors consume more electricity when they are unloaded than do multiple smaller compressors with similar overall capacity.

Pressure drop minimization. An excessive pressure drop will result in poor system performance and excessive energy consumption. Flow restrictions of any type in a system, such as an obstruction or roughness, results in higher operating pressures than are truly needed. Resistance to flow increases the drive energy on positive displacement compressors by 1% of connected power for each 2 psi of differential (U.S. DOE and CAC, 2003). The highest pressure drops are usually found at the points of use, including undersized or leaking hoses, tubes, disconnects, filters, regulators, valves, nozzles, and lubricators (demand side), as well as air/lubricant separators on lubricated rotary compressors and after-coolers, moisture separators, dryers, and filters (supply side).

Minimizing pressure drop requires a systems approach in design and maintenance. Air treatment components should be selected with the lowest possible pressure drop at specified maximum operating conditions and best performance. Manufacturers' recommendations for maintenance should be followed, particularly in air filtering and drying equipment, which can have damaging moisture effects like pipe corrosion. Finally, the distance the air travels through the distribution system should be minimized.

Inlet air temperature reduction. If airflow is kept constant, reducing the inlet air temperature reduces the energy used by the compressor. In many plants, it is possible to reduce inlet air temperature to the compressor by taking suction from outside the building. As a rule of thumb, each 5°F (3°C) will save 1% compressor energy use (CADDET, 1997; Parekh, 2000). Payback periods of two to five years have been reported for importing fresh air (CADDET, 1997). In addition to energy savings, compressor capacity is increased when cold air from outside is used.

Controls. The primary objectives of compressor control strategies are to shut off unneeded compressors and to delay bringing on additional compressors until needed. Energy savings for sophisticated compressor controls have been reported at around 12% annually (Radgen and Blaustein, 2001). An excellent review of compressor controls can be found in Compressed Air Challenge® Best Practices for Compressed Air Systems (Second Edition) (Scales and McCulloch, 2007). Common control strategies for compressed air systems include:

- *Start/stop (on/off) controls*, in which the compressor motor is turned on or off in response to the discharge pressure of the machine. Start/stop controls can be used for applications with very low duty cycles and are applicable to reciprocating or rotary screw compressors. The typical payback for start/stop controls is one to two years (CADDET, 1997).

- *Load/unload controls*, or constant speed controls, which allow the motor to run continuously but unload the compressor when the discharge pressure is adequate. In most cases, unloaded rotary screw compressors still consume 15% to 35% of full-load power while delivering no useful work (U.S. DOE and CAC, 2003). Hence, load/unload controls can be inefficient.

- *Modulating or throttling controls*, which allow the output of a compressor to be varied to meet flow requirements by closing down the inlet valve and restricting inlet air to the compressor. Throttling controls are applied to centrifugal and rotary screw compressors.

- *Single master sequencing system controls*, which take individual compressor capacities on-line and off-line in response to monitored system pressure demand and shut down any compressors running unnecessarily. System controls for multiple compressors typically offer a higher efficiency than individual compressor controls.

- *Multi-master controls*, which are the latest technology in compressed air system control. Multi-master controls are capable of handling four or more compressors and provide both individual compressor control and system regulation by means of a network of individual controllers (Martin et al., 2000). The controllers share information, allowing the system to respond more quickly and accurately to demand changes. One controller acts as the lead, regulating the whole operation. This strategy allows each compressor to function at a level that produces the most efficient overall operation. The result is a highly controlled system pressure that can be reduced close to the minimum level required (U.S. DOE and CAC, 2003). According to Nadel et al. (2002), such advanced compressor controls are expected to deliver energy savings of about 3.5% where applied.

In addition to energy savings, the application of controls can sometimes eliminate the need for some existing compressors, allowing extra compressors to be sold or kept for backup. Alternatively, capacity can be expanded without the purchase of additional compressors. Reduced operating pressures will also help reduce system maintenance requirements (U.S. DOE and CAC, 2003).

Properly sized pipe diameters. Increasing pipe diameters to the greatest size that is feasible and economical for a compressed air system can help to minimize pressure losses and leaks, which reduce system operating pressure and lead to energy savings. Increasing pipe diameters typically reduces compressed air system energy consumption by 3% (Radgen and Blaustein, 2001). Further savings can be realized by ensuring other system components (e.g., filters, fittings, and hoses) are properly sized.

Heat recovery. As much as 90% of the electrical energy used by an industrial air compressor is converted into heat. In many cases, a heat recovery unit can recover 50% to 90% of the available thermal energy and apply it to space heating, process heating, water heating, makeup air heating, boiler makeup water preheating, and heat pump applications (Parekh, 2000). Approximately 50,000 Btu/hour of recoverable heat is available for each 100 cfm of compressor capacity (U.S. DOE and CAC, 2003). Paybacks are typically less than one year.

Heat recovery for space heating is not as common with water-cooled compressors, because an extra stage of heat exchange is required and the temperature of the available heat is somewhat low. However, with large water-cooled compressors, recovery efficiencies of 50% to 60% are typical (LBNL et al., 1998).

Natural gas engine-driven air compressors. Gas engine-driven air compressors can replace electric compressors with some advantages and disadvantages. Gas engine-driven compressors are more expensive and can have higher maintenance costs, but may have lower overall operating costs depending on the relative costs of electricity and gas. Variable-speed capability is standard for gas-fired compressors, offering a high efficiency over a wide range of loads. Heat can be recovered from the engine jacket and exhaust system. However, gas engine-driven compressors have some drawbacks, including greater maintenance needs, a shorter useful life, and a greater likelihood of downtime. According to Galitsky et al. (2005), gas engine-driven compressors currently account for less than 1% of the total air compressor market.

Ultra Creative Corporation, a U.S. manufacturer of specialty plastic bags, installed gas engine-driven compressors in its plant in Brooklyn, New York. The initial costs were $85,000 each for two 220 hp units and $65,000 for one 95 hp unit. The company reported savings of $9,000 in monthly utilities, averaging $108,000 annually (Audin, 1996).

Similarly, Nestlé Canada found that its gas engine-driven air compressor system was a cost effective option when it was operated properly. The company’s projected payback period was estimated as low as 2.6 years with a 75% efficient heat recovery system, and as high as 4.2 years without heat recovery (Audin, 1996).

16. Fan systems

Fans are used in a number of systems, including boilers, furnaces, and cooling towers. As in other motor applications, considerable opportunities exist to upgrade the performance and improve the energy efficiency of fan systems. In particular, concerns about failure or underperformance have led to many fans being oversized for their particular application (U.S. DOE-OIT, 2003b). Oversized fans do not operate at optimal efficiency and therefore waste energy. However, the efficiencies of fan systems vary considerably across impeller types (Xenergy, 1998).

A few common energy efficiency measures for industrial fans and fan systems are discussed below.[16] Additionally, a number of measures that are applicable to motors (Chapter 13) are also applicable to fan systems.

Maintenance. As for most energy using systems, a proper maintenance program for fans can improve system performance, reduce downtime, minimize repair costs, and increase system reliability. The U.S. Department of Energy recommends establishing a regular maintenance program for fan systems, with intervals based on manufacturer recommendations and experience with fans in similar applications (U.S. DOE-OIT, 2003b). Additionally, the U.S. Department of Energy recommends the following important elements of an effective fan system maintenance program (U.S. DOE-OIT, 2003b):

- *Belt inspection*. In belt-driven fans, belts are usually the most maintenance-intensive part of the fan assembly. Belts wear over time and can lose tension, which reduces their ability to transmit power efficiently. Belt inspection and tightening should be performed on a regular basis, especially for large fans because the potential size of the power loss. The repair and replacement of inefficient belt drives improves energy efficiency of the fan system by 0.5% to 4.5% (de Almeida et al., 2011).

- *Fan cleaning*. Many fans experience a significant loss in energy efficiency due to the buildup of contaminants on blade surfaces. Such build up can create imbalance problems that can reduce performance and contribute to premature wear of system components. Fans that operate in particulate-laden or high-moisture airstreams are particularly vulnerable and are therefore recommended to be cleaned regularly. Fan cleaning typically results in energy savings of 0.5% to 2.5% (de Almeida et al., 2011).

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[16] The U.S. DOE's Advanced Manufacturing Office provides a variety of resources for improving the efficiency of industrial fan systems, which can be consulted for more detailed information on many of the measures presented in this chapter. The U.S. DOE's *Improving Fan System Performance: A Sourcebook for Industry* is a particularly helpful resource (U.S. DOE, 2003b). For a collection of tips, tools, and industrial case studies on industrial fan system efficiency, visit the U.S. DOE website at: http://www1.eere.energy.gov/manufacturing/tech_deployment/fans.html.

- *Leak inspection and repair*. Leakage in a fan duct system will decrease the amount of air that is delivered to the desired end use, which can significantly reduce the efficiency of the fan system. Ductwork should be inspected on a regular basis and leaks should be repaired as soon as possible. Energy savings may vary between 2% and 5% (de Almeida et al., 2011). In systems with inaccessible ductwork, the use of temporary pressurization equipment can determine if the integrity of the system is adequate.

- *Bearing lubrication*. Worn bearings can lead to premature fan failure, as well as create unsatisfactory noise levels. Fan bearings should be monitored and lubricated frequently based on manufacturer recommendations.

- *Motor replacement*. Eventually, all fan motors will wear and will require repair or replacement. The decision to repair or replace a fan motor should be based on a life cycle costs analysis, as described in Chapter 13.

Properly sized fans. Conservative engineering practices often result in the installation of fans that exceed system requirements. Such oversized fans lead to higher capital costs, higher maintenance costs, and higher energy costs than fans that are properly sized (U.S. DOE-OIT, 2003b). Savings of replacing oversized fans with more efficient ones vary between 2% and 18% (de Almeida et al., 2011). However, other options may be more cost effective than replacing an oversized fan with a smaller fan, including (U.S. DOE-OIT, 2002d; U.S. DOE-OIT, 2003b):

- Decreasing fan speed by using different motor and fan sheave sizes (may require downsizing the motor)

- Installing an ASD or multiple-speed motor (see below)

- Using an axial fan with controllable pitch blades

Adjustable speed drives (ASDs) and improved controls. Significant energy savings can be achieved by installing adjustable speed drives on fans. Savings may vary between 8% and 35% when retrofitting fans with ASDs (de Almeida et al., 2011).

An assessment of the Paramount Petroleum Corp.'s asphalt refinery in Paramount, California identified the opportunity to install ASDs on six motors in the cooling tower, ranging from 40 hp to 125 hp. The motors were operated manually and were oversized for operation in the winter. If ASDs were installed at all six motors to maintain the cold-water temperature set point, electricity savings of 1.2 million kWh/year could be achieved (U.S. DOE-OIT, 2003). Annual savings were estimated at $46,000 and the payback was relatively high at 5.8 years due to the size of the motors.

Adjustable speed drives can also help to reduce energy consumption in combustion air fans in steam boilers. At a fertilizer plant of PCS Nitrogen Inc. in Augusta (Georgia) the installation of a variable speed fan eliminated the generation of excess steam during low load periods, resulting in annual energy savings of 76,400 MMBtu (cost savings of $420,000) with a payback time of only 2 months (U.S. DOE-OIT, 2005d).

High efficiency belts (cog belts). Belts make up a variable, but significant portion of the fan system in many plants. It is estimated that about half of the fan systems use standard V-belts, and about two-thirds of these could be replaced by more efficient cog belts (U.S. DOE-OIT, 2002d). Standard V-belts tend to stretch, slip, bend and compress, which lead to a loss of efficiency. Replacing standard V-belts with cog belts can save energy and money, even as a retrofit. Cog belts run cooler, last longer, require less maintenance and have an efficiency that is about 2% higher than standard V-belts. Typical payback periods will vary from less than one year to three years.

Duct leakage repair. Duct leakage can waste significant amounts of energy in fan and ventilation systems. Measures for reducing duct leakage include installing duct insulation and performing regular duct inspection and maintenance, including ongoing leak detection and repair. For example, according to studies by Lawrence Berkeley National Laboratory, repairing duct leaks in industrial and commercial spaces could reduce HVAC energy consumption by up to 30% (Galitsky et al., 2005).

Because system leakage can have a significant impact on fan system operating costs, the U.S. Department of Energy recommends considering the type of duct, the tightness and quality of the fittings, joints assembly techniques, and the sealing requirements for duct installation as part of the fan system design process as proactive leak prevention measures (U.S. DOE-OIT, 2003b).

17. Lighting

Lighting and other utilities represent less than 3% of total electricity use in refineries. Still, potential energy efficiency improvement measures exist, and may contribute to an overall energy management strategy. Because of the relatively minor importance of lighting and other utilities, this Guide focuses on the most important measures that can be undertaken to improve the efficiency of these systems. Additional information on lighting guidelines and efficient practices is available from the Illuminating Engineering Society of North America (www.iesna.org) and the California Energy Commission (CEC, 2008).

Turning off lights in unoccupied areas. An easy and effective measure is to encourage personnel to turn off lights in unoccupied building spaces. An energy management program that aims to improve the awareness of personnel with regard to energy use can help staff get in the habit of switching off lights and other equipment when not in use.

A plant-wide assessment of the Valero refinery in Houston reported the potential of saving 175,000 kWh/yr by turning off outdoor lighting during daylight hours. This measure will not involve any capital costs and will result in annual savings of $6,000 (U.S. DOE-OIT, 2005)

Lighting controls. Lights can be shut off during non-working hours by automatic controls, such as occupancy sensors, which turn off lights when a space becomes unoccupied. Occupancy sensors can save up to 10% to 20% of facility lighting energy use (Galitsky et al., 2005). Numerous case studies throughout the United States suggest that the average payback period for occupancy sensors is approximately 1 year (IAC, 2012). Manual controls can be used in conjunction with automatic controls to save additional energy in smaller areas. One of the easiest measures is to install switches to allow occupants to control lights. Other lighting controls include daylight controls for indoor and outdoor lights, which adjust the intensity of electrical lighting based on the availability of daylight.

An example of energy-efficient lighting control is illustrated by Figure 15, which depicts five rows of overhead lights in a workspace. During the brightest part of the day, ample daylight is provided by the window and thus only row C would need to be turned on. At times when daylight levels drop, all B rows would be turned on and row C would be turned off. Only at night or on very dark days would it be necessary to have both rows A and B turned on (Cayless and Marsden, 1983). These methods can also be used as a control strategy on a retrofit by adapting the luminaries already present. For example, turning on the lighting in rows farthest away from the windows during the brightest parts of the day, and turning on additional rows when needed.

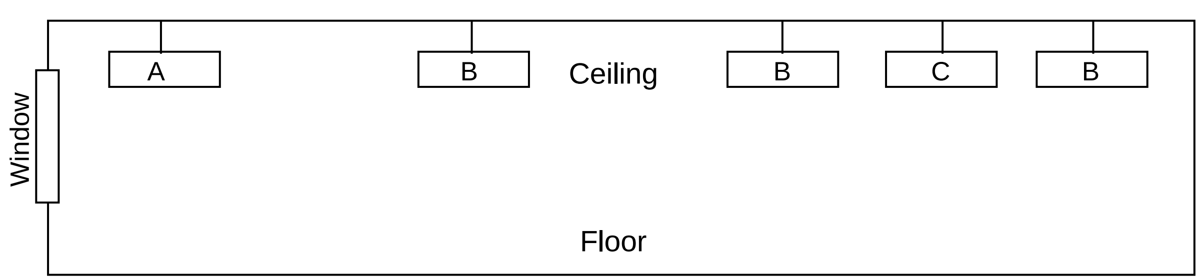

Figure 15. Lighting placement and controls.

Replacement of lighting in exit signs. Energy costs can be reduced by switching from incandescent lamps to light emitting diodes (LEDs) or radium strips in exit sign lighting. An incandescent exit sign uses about 40 W, while LED signs may use only about 4W to 8W, reducing electricity use by 80% to 90%. A 1998 Lighting Research Center survey found that about 80% of exit signs being sold use LEDs (LRC, 2001). The lifetime of an LED exit sign is about 10 years, compared to 1 year for incandescent signs, which can reduce exit sign maintenance costs considerably. In addition to exit signs, LEDs are increasingly being used for path marking and emergency way finding systems. Their long life and cool operation allows them to be embedded in plastic materials, which makes them well suited for such applications (LRC, 2001).

New LED exit signs are inexpensive, with prices typically starting at around $20. The U.S. EPA's ENERGY STAR program website (http://www.energystar.gov) provides a list of suppliers of LED exit signs.

Tritium exit signs are an alternative to LED exit signs. Tritium signs are self-luminous and thus do not require an external power supply. The advertised lifetime of these signs is around 10 years and prices typically start at around $150 per sign.

The Flying J Refinery in North Salt Lake, Utah (currently owned by Big West Oil) replaced exit signs by new LED signs, saving about $1,200/year (Brueske et al., 2002).

Replace magnetic ballasts with electronic ballasts. A ballast regulates the amount of electricity required to start a lighting fixture and maintain a steady output of light. Electronic ballasts can require 12% to 30% less power than their magnetic predecessors (Cook, 1998; Galitsky et al., 2005). New electronic ballasts have smooth and silent dimming capabilities, in addition to longer lives (up to 50% longer), faster run-up times, and cooler operation than magnetic ballasts (Eley et al., 1993; Cook, 1998). New electronic ballasts also have automatic switch-off capabilities for faulty or end-of-life lamps.

Replacement of T-12 tubes by T-8 tubes. In many industrial facilities, it is common to find T-12 lighting tubes in use. T-12 lighting tubes are 12/8 inches in diameter (the "T-" designation refers to a tube's diameter in terms of 1/8 inch increments). T-12 tubes consume significant amounts of electricity, and also have extremely poor efficacy, lamp life, lumen depreciation, and color rendering index. Because of this, the maintenance and energy costs of T-12 tubes are high. T-8 lighting tubes have around twice the efficacy of T-12 tubes, and can last up to 60% longer, which leads to savings in maintenance costs. Typical energy savings from the replacement of a T-12 lamp by a T-8 lamp are around 30% (Galitsky et al. 2005).

Replacement of mercury lights. Where color rendition is critical, metal halide lamps can replace mercury or fluorescent lamps with energy savings of up to 50%. Where color rendition is not critical, high-pressure sodium lamps offer energy savings of 50% to 60% compared to mercury lamps (Price and Ross, 1989).

High-intensity discharge (HID) voltage reduction. Reducing lighting system voltage can also save energy. A Toyota production facility installed reduced-voltage HID lights and realized a 30%

reduction in lighting energy consumption (Galitsky et al., 2005). Commercial products are available that attach to a central panel switch (controllable by computer) and constrict the flow of electricity to lighting fixtures, thereby reducing voltage and saving energy with an imperceptible loss of light. Voltage controllers work with both HID and fluorescent lighting systems and are available from multiple vendors.

High-intensity fluorescent lights. Traditional HID lighting can be replaced with high-intensity fluorescent lighting systems, which incorporate high-efficiency fluorescent lamps, electronic ballasts, and high-efficacy fixtures that maximize output to work areas. These systems have lower energy consumption, lower lumen depreciation over the lifetime of the lamp, better dimming options, faster startup and re-strike capabilities, better color rendition, higher pupil lumens ratings, and less glare than traditional HID systems (Martin et al., 2000).

LED Lighting. Light emitting diode (LED) lights have been receiving a lot of attention as the next generation of energy-efficient lighting. In typical fluorescent lighting, electrical arcs are used to excite mercury and phosphorous compounds, which then emit light. LED lights are semiconductor diodes that use far less energy to emit the same lumens of light. Several new LED light products that are compatible with current light fixtures, such as T-8 light fixtures, are emerging on the market (Myer et al., 2009).

Daylighting. Daylighting involves the efficient use of natural light in order to minimize the need for artificial lighting in buildings. Increasing levels of daylight within rooms can reduce electrical lighting loads by up to 70% (CADDET, 2001; IEA, 2000). Unlike conventional skylights, an efficient daylighting system may provide evenly dispersed light without creating heat gains, which can reduce the need for cooling compared to skylights. Daylighting differs from other energy efficiency measures because its features are integral to the architecture of a building; therefore, it is applied primarily to new buildings and incorporated at the design stage. However, existing buildings can sometimes be cost-effectively refitted with daylighting systems.

Daylighting can be combined with lighting controls to maximize its benefits. Because of its variability, daylighting is almost always combined with artificial lighting to provide the necessary illumination on cloudy days or after dark (see also Figure 15). Daylighting technologies include properly placed and shaded windows, atria, clerestories, light shelves, and light ducts. Clerestories, light shelves, and light ducts can accommodate various angles of the sun and redirect daylight using walls or reflectors.

More information on daylighting can be found at the website of the Daylighting Collaborative led by the Energy Center of Wisconsin (http://www.daylighting.org/).

18. Power Generation

Most refineries have some form of onsite power generation, and in the United States approximately 30% of electricity requirements in petroleum refining are met with onsite generated power (U.S. EPA, 2007). Refineries offer an excellent opportunity for energy-efficient power generation in the form of combined heat and power production (CHP). CHP provides the opportunity to use internally generated fuels for power production, allowing greater independence from grid operation, and even export to the grid. This increases the reliability of supply, as well as its cost-effectiveness. The costs and benefits of exporting power to the grid will vary based on the regulation in the state where the refinery is located. Not all states allow wheeling of power (i.e., sales of power directly to another customer using the grid for transport), and some regulations may differ with respect to the tariff structure for power sales to the grid operator.

18.1 Combined heat and power generation (CHP)

The petroleum refining industry is one of the largest users of cogeneration or CHP in the country. Current installed capacity is estimated to be over 6,700 MWe (ICF International, 2010), making it the largest CHP user after the chemical and pulp & paper industries. Still, only about 10% of all steam used in refineries is generated in cogeneration units. Hence, the petroleum refining industry has a tremendous potential for increased application of CHP. In fact, an efficient refinery can be a net exporter of electricity. The potential for exporting electricity is further enlarged when considering the new, innovative technologies currently used commercially at selected petroleum refineries (discussed below). The potential for conventional cogeneration installations is estimated at an additional 5,700 MWe (Onsite, 2000), most of which is concentrated in medium to large-scale gas turbine based installations. The economics of CHP operation at refineries are generally attractive, especially with low natural gas prices, although these systems require a fairly large investment ($1,000-2,500/kW) (U.S. EPA, 2010).

Where process heat, steam or cooling and electricity are used, cogeneration plants are significantly more efficient than standard power plants because they take advantage of waste heat that would be classified as losses in conventional power plants. In addition, transportation losses are minimized when CHP systems are located at or near the refinery. Third parties have developed CHP for use by refineries, and frequently own and operate the system for the refinery, shifting the capital expenditures associated with CHP projects away from the refinery while still allowing refineries to gain a proportion of the benefits of a more energy-efficient system of heat and electricity supply. In fact, about 60% of the cogeneration facilities operated within the refinery industry are operated by third party companies (Onsite, 2000). For example, in 2001 BP's Whiting, Indiana refinery installed a new 525 MW cogeneration unit with a total investment of $250 million carried by Primary Energy Inc. Many new cogeneration projects can be financed in this way. Other opportunities consist of joint-ventures between the refinery, an energy generation or operator to construct a cogeneration facility.

Optimization of the operation strategy of CHP units and boilers is an area in which additional savings can be achieved. The development of a dispatch optimization program at the Hellenic

Aspropyrgos Refinery (Greece) to meet steam and electricity demand demonstrates the potential energy and cost-savings (Frangopoulos et al., 1996).

For systems requiring cooling, absorption cooling can be combined with CHP to utilize waste heat to produce cooling power. In refineries, refrigeration and cooling consume between 5% and 6% of all electricity. Cogeneration, in combination with absorption cooling, has been demonstrated for building sites and sites with refrigeration leads. No case studies within the petroleum refining industry were identified for this technology.

Innovative gas turbine technologies can make CHP more attractive for sites with large variations in heat demand. Steam injected gas turbines (STIG or Cheng cycle) can absorb excess steam to boost power production by injecting the steam in the turbine. The size of typical STIGs ranges from around 5 MWe to 125 MWe. STIGs have been installed at over 50 sites worldwide, and are found in various industries and applications, especially within Japan, Europe, and the United States. The total energy savings and the payback period will depend on local circumstances (e.g., energy patterns, power sales conditions). In the United States, the Cheng Cycle is marketed by International Power Technology (San Jose, California). The Austrian oil company OMV has considered the use of a STIG to upgrade an existing cogeneration system, and there are currently several applications of steam injected gas turbines in the chemical industry worldwide.

Steam turbines are often used as part of the CHP system in a refinery, or as stand-alone systems for power generation. The efficiency of the steam turbine is determined by the inlet steam pressure and temperature, as well as by the outlet pressure. Each turbine is designed for a certain steam inlet pressure and temperature, and operators should ensure that the steam inlet temperature and pressure are optimal. An 18°F decrease in steam inlet temperature will reduce the efficiency of the steam turbine by 1.1% (Patel and Nath, 2000). Similarly, maintaining the exhaust vacuum of a condensing turbine or the outlet pressure of a backpressure turbine at too high a level will result in efficiency losses.

Valero's Houston refinery constructed a 34 MW cogeneration unit in 1990, using two gas turbines and two heat recovery steam generators (boilers). The system supplies all of the electricity for the refinery, and occasionally allows for export to the grid. The CHP system has resulted in savings of about $55,000/day (Valero, 2003).

In 2004, ExxonMobil installed a natural gas-fired CHP system to support the refinery complex in Baytown, Texas. This is one of the largest complexes in the United States consisting of a refinery, two research centers, and two processing plants for fuel conversion, lubricant production, and petrochemical processing. Up to 171 MW of electricity and 560,000 pounds of steam per hour can be produced by the CHP system. Operating efficiency is estimated at 73% and therefore requires approximately 33% less fuel than typical onsite thermal generation and purchased electricity (U.S. EPA, 2006b). ExxonMobil also installed three CHP units to produce efficient power and steam for its Beaumont refinery in 2005. This will provide 470 MW of power and 3.1 million pounds of steam per hour. Only 110 MW power will be used on-site, with the balance being sold on the market (U.S. EPA, 2006b).

BP Global Power, the power development unit of BP began operating a CHP system at BP's refinery in Texas City in 2004. This CHP plant is designed to produce up to 564 MW and 3.1 million pounds of steam per hour for its largest refinery and chemical plant. Electricity not used on-site is delivered to the local electricity grid (U.S. EPA, 2006b). At BP's Whiting refinery in Indiana, a 525 MW CHP plant is being built with investment costs of about $210 million.

Teroso's Salt Lake City refinery installed a CHP plant in 2004, which runs on a mixture of refinery gas and purchased natural gas. The CHP plant is designed to cover the heat and power consumption of the refinery, with excess electricity sold to the grid. Total project costs were $25 million with monthly energy savings of $200,000. Greenhouse gas emissions were reduced by more than 500 tons per year (U.S. DOE, 2006).

Even for small refineries, CHP is an attractive option. An assessment of the Paramount Petroleum Corp.'s asphalt refinery in Paramount, California identified the opportunity to install a CHP unit at this refinery as the largest energy saving measure. A 6.5 MWe gas turbine CHP unit would result in annual energy savings of $3.8 million and has a payback period 2.5 years (U.S. DOE-OIT, 2003). In addition, the CHP unit would reduce the risk of power outages for the refinery. The investment costs assume best available control technology for emission reduction. The CHP system was installed in 2002.

18.2 Gas expansion turbines

Natural gas is often delivered to a refinery at very high pressures, ranging from 200 to 1,500 PSI. Expansion turbines use the pressure drop from decompressing natural gas to generate power or to use in a process heater. An expansion turbine includes both an expansion mechanism and a generator. In an expansion turbine high-pressure gas is expanded to produce work. Energy is extracted from pressurized gas, which lowers gas pressure and temperature. These turbines have been used for air liquefaction in the chemical industry for several decades. The application of expansion turbines as energy recovery devices started in the early 1980s (SDI, 1982). The technology has much improved since the 1980's and is highly reliable today. A simple expansion turbine consists of an impeller (expander wheel) and a shaft and rotor assembly attached to a generator. Expansion turbines are generally installed in parallel with the regulators that traditionally reduce pressure in gas lines. If flow is too low for efficient generation, or if the expansion turbine fails, pressure is reduced in the traditional manner. The drop in pressure in the expansion cycle causes a drop in temperature to decline. While turbines can be built to withstand cold temperatures, most valve and pipeline specifications do not allow temperatures below –15°C. In addition, gas can become wet at low temperatures, as heavy hydrocarbons in the gas condense. This necessitates heating the gas either just before or just after expansion. The heating is generally performed with either a combined heat and power (CHP) unit or a nearby source of waste heat. Petroleum refineries often have excess low-temperature waste heat, making a refinery an ideal location for a power recovery turbine. Industrial companies and utilities in Europe and Japan have installed expansion turbine projects; however, it is unknown if any petroleum refineries have installed this technology.

In 1994, the Corus integrated steel mill at Ijmuiden, the Netherlands, installed a 2 MW power recovery turbine. The mill receives gas at 930 psi, preheats the gas, and expands with the turbine to 120 psi. The maximum turbine flow is 1.4 million ft^3/hr (40,000 m^3/hr), while the average capacity is 65%, resulting in an average flow of 0.9 million ft^3/hr. The turbine uses cooling water from the hot strip mill of approximately 160°F (70°C) to preheat the gas (Lehman and Worrell, 2001). The 2 MW turbine generated roughly 11,000 MWh of electricity in 1994, while the strip mill delivered a maximum of 12,500 MWh of waste heat to the gas flow. Thus, roughly 88% of the maximum heat input to the high-pressure gas emerged as electricity. The cost of the installation was $2.6 million, and the operation and maintenance costs total $110,000 per year. With a total income of $710,000 per year from electricity generation (at the 1994 Dutch electricity cost of 6.5 cents per kWh), the payback period for the project was 4.4 years.

18.3 Steam expansion turbines

In many steam systems, high-pressure steam produced by boilers is reduced in pressure for use in different processes. For example, steam is generated at 120 to 150 psig, flows through the distribution system within the plant, and pressure is reduced to between 10 and 15 psig for use in another process. Once the heat has been extracted, the condensate is often returned to the steam generating plant. Typically, the pressure reduction is accomplished through a pressure reduction valve (PRV); however, these valves do not recover the energy embodied in the pressure drop. This energy could be recovered by using a micro-scale backpressure steam turbine, which are available in ratings as low as 50 kW. Backpressure steam turbines should be considered when a PRV has a constant steam flow of at least 3,000 lb/hr and a steam pressure drop of at least 100 psi. Several manufactures produce these turbine sets, including Turbosteam (previously owned by Trigen) and Dresser-Rand.

The potential for application will depend on the particular refinery and steam system used. Applications of this technology have been commercially demonstrated for campus facilities, pulp and paper, food, and lumber industries, but not yet in the petroleum industry. The investments of a typical expansion turbine vary from about $900/kW for a 150 kW system to less than $200/kW for a 2,000 kW system. They are designed for a minimum 20-year service life and have low maintenance requirements (U.S. DOE, 2012i).

An assessment of the Bradford refinery of the American Refining Group in Pennsylvania identified the possibility to install a cogeneration backpressure turbine to eliminate let down steam flow under all conditions. This would result in electricity savings of 3,700,000 kWh/year, but would increase fuel use by 15,000 MMBtu/year. Though yearly energy savings of such a cogeneration back pressure turbine would amount to $138,000, it is not seen as a viable project, because of the relatively low cost of electricity coupled with un-foreseen utility interconnection costs (ARG, 2007).

18.4 Turbine pre-coupling

Pre-coupling - Distillation unit. Turbines can be pre-coupled to a crude distillation unit or other continuously operated processes with an applicable temperature range. The off gases of the turbine can be used to supply the heat for the distillation furnace, provided the outlet temperature of the turbine is high enough. One method is the so-called “repowering” option, under which the furnace is not modified, but the combustion air fans in the furnace are replaced by a gas turbine. The exhaust gases still contain a considerable amount of oxygen, and can thus be used as combustion air for the furnaces. The gas turbine can deliver up to 20% of the furnace heat. Two of these installations are installed in the Netherlands, with a total capacity of 35 MW_e at refineries (Worrell et al., 1997).

Pre-coupling - Steam methane reformer.

Gas turbines can also be pre-coupled to a steam methane reformer (SMR). Cogeneration of hydrogen and electricity can be a major improvement in energy utilization. The hot exhaust from the gas turbine (~540˚C) still contains about 13 percent oxygen and can be used as combustion air in the SMR, reducing fuel use in the reformer furnace. In a cogeneration design, the reformer convection section can also be used as a heat-recovery steam generator (HRSG) for additional power generation. Air Products and Technip have developed this integrated hydrogen and cogeneration technology and installed seven integrated facilities at refineries in the United States and Europe. Capital costs are estimated at $700/kW (U.S. EPA, 2010; Ratan et al., 2005).

A refinery on the West Coast has installed a 16 MW_e gas turbine at a reformer (Terrible et al., 1999). The flue gases of the turbine feed to the convection section of the reformer, increasing steam generation. This steam is then used to power a 20 MW_e steam turbine.

The latest (2006) integrated hydrogen/cogeneration plant commissioned by Air Products and Technip is located near Valero's Port Arthur refinery in Texas. The plant simultaneously produces 100 MW of power, 110 million scfd of hydrogen, and up to 1.2 million lb/hr of steam, which is supplied to Valero's Port Arthur refinery (Peltier, 2007).

High-temperature CHP. Alternatively, high-temperature CHP may be used to take advantage of larger CHP potentials and associated energy savings. Under high-temperature CHP, the flue gases of a CHP plant are used to heat the input of a furnace or to preheat the combustion air. The potential at U.S. refineries is estimated at 34 GW (Zollar, 2002). This option requires replacing the existing furnaces. This is due to the fact that the radiative heat transfer from gas turbine exhaust gases is much smaller than from combustion gases, due to their lower temperature (Worrell et al., 1997). A distinction is made between two different types. In the first type, the exhaust heat of a gas turbine is led to a waste heat recovery furnace, in which the process feed is heated. In the second type, the exhaust heat is led to a "waste heat oil heater" in which thermal oil is heated. By means of a heat exchanger, the heat content is then transferred to the process feed. In both systems, the remaining heat in the exhaust gases after heating the process feed should be used for lower temperature purposes to achieve a high overall efficiency. The second type is more reliable, due to the fact that a thermal oil buffer can be included. The main difference is that in the first type the process feed is directly heated by exhaust gases, where the second uses thermal oil as an intermediate, leading to larger flexibility. The simple payback period is estimated at 3 to 5 years, depending on the electricity costs. Additional investments compared to a traditional furnace were estimated at $630/kW (Bailey and Worrell, 2005).

An instance of the first type of high-temperature CHP is installed in Fredericia, Denmark at a Shell refinery, where the low temperature remaining heat is used for district heating.

In 2009, ExxonMobil installed a high efficiency cogeneration plant at its Antwerp refinery in Belgium. The cogeneration unit produces 125 MW of power and 380,000 pounds of steam per hour, and is uniquely integrated with refinery operations. It uses the heat of the cogeneration unit to heat half of the crude oil that is processed in the refinery (crude capacity of 305,000 barrels per day) to distillation temperature. This results in considerable savings in furnace capacity of the distillation unit (ExxonMobil, 2009).

18.5 Gasification

Gasification provides the opportunity for cogeneration using the heavy bottom fraction and refinery residues (Marano, 2003). Because of the increased demand for lighter products and rising use of conversion processes, refineries will have to manage a greater proportion of heavy bottoms and residues. Gasification of the heavy fractions and coke to produce synthesis gas can help to efficiently remove these by-products. The state-of-the-art gasification processes combine the heavy by-products with oxygen at high temperature in an entrained bed gasifier. Due to the limited oxygen supply, the heavy fractions are gasified to a mixture of carbon monoxide and hydrogen. Sulfur can easily be removed in the form of H_2S to produce elemental sulfur. The synthesis gas can be used as feedstock for chemical processes. However, the most attractive application is the generation of power in an Integrated Gasification Combined Cycle (IGCC). In this installation, the synthesis gas is combusted in a gas turbine with an adapted combustion chamber to handle the low to medium-BTU gas, generating electricity. The hot flue gases are used to generate steam. The steam can be used onsite or used in a steam turbine to produce additional electricity (i.e., the combined cycle). Cogeneration efficiencies can be up to 75% (LHV) and for power production alone the efficiency is estimated at 38% to 39% (Marano, 2003). In addition, the IGCC could be a promising technology for CO_2 capture, and can easily accommodate a CO_2 capture section based on available state-of-the-art technologies (Domenichini and Mancuso, 2008).

Entrained bed IGCC technology was originally developed for refinery applications, but is also used for the gasification of coal. Hence, the major gasification technology developers were oil companies like Shell and Texaco. IGCC provides a low-cost opportunity to reduce emissions (SO_x, NO_x) when compared to combustion of the residue, and to process the heavy bottoms and residues while producing power and/or feedstocks for the refinery. Approximately 40 refineries in the United States have a sufficiently large capacity to make this technology economically viable (Marano, 2003).

There is a lot of experience with IGCC using refinery fractions in various countries across the world. The Shell refinery in Pernis, the Netherlands, uses IGCC to process 1650 tonnes per day of heavy residue from the visbreaker and other residues to generate 117 MWe of power and 285 tonnes of hydrogen for the refinery. In Italy, four refineries (API Falconara, ENI Sannazzaro, Sarlux Sarroch, and Isab Priolo) use IGCC to treat visbreaker residue to produce a total 1600 MWe of power. In the United States, the Frontier Oil Refinery in El Dorado, Kansas, produces 35 MWe from petroleum coke and waste oils. Also the Delaware City Refinery in Delaware City, Delaware, operates an IGCC that processes 2000 tonnes per day petroleum coke to produce 120 MWe of power. ExxonMobil's Baytown, Texas refinery operates a syngas plant producing syngas from heavy oil and petroleum coke; however, this is not combusted to produce power (Ekbom, 2007). New installations have been announced or are under construction in the United States for the refineries at Carson, California (BP) and Lake Charles, Louisiana (CITGO).

The investment costs will vary by capacity and products of the installation. Marano (2003) reports the capital costs of a gasification unit consuming 2000 tons per day of heavy residue at approximately $229 million for the production of hydrogen and $347 million for an IGCC unit. A study of Domenichini and Mancuso (2008) shows total investment costs to be about $1100 million for an IGCC with a flowrate of 3,100 tons per day of heavy residue, a net output of 185 MWe, and a hydrogen production rate of 100,000 Nm^3/h. The operating cost savings will depend on the costs of power, natural gas, and the costs of heavy residue disposal or processing.

19. Other Opportunities

19.1 Process changes and design

Desalter. Alternative designs for desalting include multi-stage desalters and a combination of AC and DC fields. These alternative designs may lead to increased efficiency, lower energy consumption, and a reduction in wash water usage (IPPC, 2002).

Catalytic reformer - Increased product recovery. Product recovery from a reformer may be limited by the temperature of the distillation to separate the various products. An analysis of a reformer at the Colorado Refinery in Commerce City, Colorado (now operated by Suncor Energy), showed increased LPG losses at higher temperatures in the summer. The LPG would either be flared or used as fuel gas. By installing a waste heat driven ammonia absorption refrigeration plant, the recovery temperature was lowered, debottlenecking the compressors and the unsaturated light-cycle oil streams (Petrick and Pellegrino, 1999). The heat pump uses the reformer's 290°F (143°C) waste heat stream to drive the compressor. The system was installed in 1997 and was supported by the U.S. Department of Energy as a demonstration project, resulting in annual savings of 65,000 barrels of LPG. The recovery rate varies with ambient temperature. The liquid product fraction contained a higher percentage of heavier (C_5, C_6+) products. The payback period is estimated at 1.5 years (Brant et al., 1998).

Slurry-phase hydrocracking technology. Slurry-phase hydrocracking technology is a hydrocracking process based on the unique features of a dispersed (slurry) catalyst. This technology was originally designed for coal liquefaction and is able to cope with the formation of solids as a result of asphaltene degradation. The principles of slurry-phase hydrocracking essentially overcome the limitations of fixed-bed and ebullating-bed technologies, providing a substantially higher conversion of residue. Some slurry-type processes can achieve residue conversion of more than 90%. Research on this technology is very active, and various technologies are developed that differ in operating pressures and catalyst additives. The technologies are in different stages of development, from a pilot stage to industrial application (Zhang et al., 2007; Butler et al., 2009). Some of the slurry phase processes developed include: SRC Uniflex (PetroCanada), HDHPLUS (INTEVEP, IFP, Axens), Veba Combi-Cracker (BP), and Eni Slurry Technology (EST) (EniTechnologie).

Several demo units of the HDHPLUS vacuum residue slurry technology have been operated in Germany and Venezuela. The first commercial application of the HDHPLUS technology (50,000 barrel per stream day) was planned to start up at the refinery of Puerto La Cruz in 2012 (Venezuela, Petróleos de Venezuela S.A.) (Morel, 2009).

The EST technology has been proven successful in a commercial demonstration slurry-phase hydrocracking process at ENI's Taranto refinery in Italy, which has been running since 2005. It converts residues and produces high-quality diesel oil and catfeed with a low-sulfur and aromatic content that can be processed further. Currently, a full-scale industrial 23,000 barrels per stream day slurry-phase hydrocracking unit is being constructed at ENI's Sannazzaro refinery in Italy, which is scheduled to start up at the end of 2012. A second 14,000 bpsd-slurry-phase hydrocracking project at another refinery of ENI is in advanced study stages (Rispoli et al., 2009).

Saturated gas plant. A plant-wide assessment of Chevron's Salt Lake City, Utah refinery identified savings by constructing a new saturated gas plant to process all saturated light ends from the crude unit, hydrotreaters, and reformer. The unsaturated light ends from the FCC and coker, would be processed in the existing FCC gas recovery unit. Only the unsaturated gas from the FCC gas recovery unit will be fed to the alkylation plant, thereby improving feed material quality. The saturated gas from the saturated gas plant could be sold as an end-product. The separation of saturated gas from unsaturated gas will save energy by avoiding reprocessing of the saturated gas in the alkylation plant. Fuel savings are estimated to be 20,000 MMBtu per year in natural gas and cost savings will be $3.6 million per year. Capital costs of a saturated gas plant at the Salt Lake City refinery are estimated at $15 million (U.S. DOE-OIT, 2004d). The opportunities and savings of installing a saturated gas plant depend on the individual refinery's design and flows.

Coker – Steam blowdown system. A coke drum blowdown system recovers hydrocarbon and steam vapors generated during the quenching and steaming portions of the decoking process. Generally, when the coke drum is cooled, the steam and hydrocarbon vapors may be vented, if not recovered to meet air quality regulations, and high pressure water jets are used to cut the coke from the drum. The hydrocarbons from the blowdown system could be recovered or used for combustion in a process heater or boiler. The sulfur content of this stream may demand further processing before combustion (U.S. EPA, 2010). In addition, the hot water from the blowdown system can be recovered and recycled in steam generation. Such a closed blowdown system maximizes hydrocarbon and water recovery from coking.

19.2 Alternative production flows

FCC - Process flow changes. The product quality demands and feeds of FCCs may change over time. The process design should remain optimized for this change. Increasing or changing the number of pumparounds can improve energy efficiency of the FCC, as it allows increased heat recovery (Golden and Fulton, 2000). A change in pumparounds may affect the potential combinations of heat sinks and sources.

New design and operational tools enable the optimization of FCC operating conditions, enhancing product yields. Petrick and Pellegrino (1999) cite studies that have shown that optimization of the FCC-unit with appropriately modified equipment and operating conditions can increase the yield of high-octane gasoline and alkylate from 3% to 7% per barrel of crude oil, resulting in energy savings.

19.3 Other opportunities

Flare optimization. Flares are used to safely dispose of combustible gases and to avoid release to the environment of these gases through combustion or oxidation. All refineries operate flares, which, in the majority of refineries, are used to burn gases in the case of a system upset. Older flare systems have a pilot flame that is burning continuously. This results in losses of natural gas. Also, this may lead to a loss of methane, a powerful greenhouse gas, to the environment if the pilot flame is extinguished.

Modern flare pilot designs are more efficient, using electronic ignition when the flare is needed, operating sensors for flame detection and to shut off the fuel gas, and reducing methane emissions. These systems can reduce average natural gas use to below 45 scf/hour. The spark ignition systems use little electrical power, and can be supplied by photovoltaic (solar cell) system, making the whole system independent of an external power supply. These systems are marketed by a number of suppliers, including, for example, John Zink.

Chevron replaced a continuous burning flare with an electronic ignition system at a refinery, resulting in savings of 1.68 million scf/year (168 MMBtu/year) with a payback of less than 3 years.

Heated storage tanks. Some storage tanks at the refinery are kept at elevated temperatures to control the viscosity of the product stored. Insulation of the tank can reduce the energy losses.

An assessment of the Fling J Refinery at North Salt Lake, Utah (currently owned by Big West Oil) found that the insulation of the top of an 80,000 bbl storage tank that is heated to a temperature of 225°F (107°C) would result in annual savings of $148,000 (Brueske et al., 2002).

An assessment of the American Refining Group refinery in Bradford, Pennsylvania, identified that the insulation on some of the heated product storage tanks had blown off and had not been replaced. Re-insulating the 12 storage tanks would result in annual savings of 12,000 MMBtu and $54,000 (ARG, 2007)

19.4 Innovative technologies

The technologies described in this section are still undergoing research and development and cannot be considered commercial at this moment. Available information is limited and results shown have yet to be confirmed by case studies.

Coker - Improved delayed coking. The improved delayed coker unit (IDCU) is a combination of delayed coking and fluid coking methods that converts heavy hydrocarbons into a range of lighter liquid products and coke. This new process, developed by U.S. Cokertech LLC., is claimed to reduce the required duration of the alternating drum-fill decoking cycles from 18 to 6 hours, thereby increasing drum capacity. This is the result of eliminating the need for drum quenching, draining, unheading, hydraulic decoking, reheating and pressure-testing procedures in the decoking cycle. The decoking cycle includes a steam-out and coke-product removing step, a pressure system to keep the drum at constant pressure, a heavy-duty crusher that provides smaller coke particle sizes, and a lifting steam system to remove the coke from the drum. The increased drum capacity and lower utility usage will result in reduced operation and maintenance costs. It is claimed that all existing delayed coking units can be converted without shutdown and with minimum expenses (HCP, 2009).

Distillation - Internal heat-integrated distillation column. Fine-tuning the heat integration between the rectifying and stripping sections of the distillation column offers potential energy savings. This type of heat integration has not been applied in the chemical and petroleum industries on a commercial scale yet, though in 2005 a pilot plant column was constructed at Maruzen Petrochemical Co., Ltd. (Japan). In a heat-integrated distillation column (HIDiC) system, the rectifying and stripping sections are separated by a compressor and throttling valve. The pressure difference implies a corresponding temperature difference, which enables heat transfer between the two sections. Both (bottom) reboiler and (top) condenser heat duties can be reduced, improving the efficiency of distillation. The pilot plant at Maruzen Petrochemical appears to be more energy efficient than the existing distillation column at this refinery, reducing its energy use for separation by 40% to 60% (Huang et al., 2008).

Distillation - Membranes. Membranes may offer future alternatives to distillation. Membranes have started to enter the refinery for hydrogen recovery (see Hydrogen Management and Recovery section), but are also being developed for other separations. An extensive study funded by the U.S. Department of Energy focused on membranes for different separations (gas/gas, fluid/fluid) and studied current state-of-the-art technologies and their potential applications in petroleum refining (Dorgan et al., 2003). Dorgan et al. (2003) concluded that membrane technology will definitely enter the refinery, although further research is needed to develop appropriate membrane materials that can withstand the petroleum refining process. Membrane technology should be evaluated as an integrated part of the specific process for which it is being implemented to warrant the full energy savings potential.

Hydrotreater – Alternative desulfurization. Desulfurization is becoming more and more important as regulations demand lower sulfur content of fuels. Desulfurization is currently mainly done by hydrotreaters. Hydrotreaters use a considerable amount direct (fuel, steam, electricity) and indirect (hydrogen) energy. Various alternatives are being developed, such as advanced hydrotreating, reactive adsorption, and oxidative desulfurization, but not all are commercially available yet (Babich and Moulijn, 2003).

Several of these alternatives are being demonstrated at refineries around the world. An advanced hydrotreating process, developed by CDTech Company, is demonstrated at Motiva's Port Arthur, Texas refinery. Oxidative desulfurization, a non-consuming hydrogen technique based on the oxidation of organic sulfur compounds, followed by the extraction of reaction products, is demonstrated at Valero's Krotz Sprinds, Louisiana refinery (currently owned by Alon). The S Zorb process, a sorbent operated in a fluidized bed reactor, is demonstrated at Phillips Borger refinery in Texas (currently owned by WRB Refining). Phillips Petroleum Co. claims a significant reduction in hydrogen consumption to produce low-sulfur gasoline and diesel (Gislason, 2001). A cursory comparison of the characteristics of the S Zorb process and that of selected hydrotreaters suggests a lower fuel and electricity consumption, but increased water consumption. Use of any alternative desulfurization technology to produce low sulfur should be evaluated on the basis of the sulfur content of the naphtha and diesel streams, and the applicability of the process to the specific conditions of the refinery.

Biodesulfurization. Biodesulfurization is an alternative to the current hydrotreater. While other alternatives to hydrotreaters are under development to desulfurize various refinery products, biodesulfurization would be a complete breakthrough in process development. It would offer mild processing conditions and reduce the need for hydrogen makeup. Both would lead to high energy savings in the refinery. Biocatalytic desulfurization (BDS) can potentially offer a low-cost alternative to hydrotreating by reducing capital and operating costs (U.S. DOE-OIT, 2003c). A study by Enchira (2003) has developed a design for the process and evaluated the economics.

The challenge is to develop bacteria that can reduce the sulfur content of gasoline to a sufficiently low level to meet fuel standards at sufficiently high rate of desulfurization. Other challenges include biocatalyst stability, oil/water separation and product recovery (Borole et al., 2003). Total desulphurization of fossil fuels by a microbial approach is not expected in the near future, as additional research is required.

Reactive distillation. The combination of conversion and separation is a major area of development for conversion processes. By combining the chemical reaction and separation in one reactor, capital costs are reduced and energy efficiency is improved. Reactive distillation offers a promising alternative to conventional reaction-distillation schemes (e.g., catalytic cracking, hydrocracking) and savings in capital cost and energy are reported between 15% and 80% (Sundmacher and Kienle, 2003; Harmsen, 2007). Furthermore, active removal of reaction products can help shift the equilibrium of the reaction and improve the conversion efficiency. About 150 reactive distillation units were in commercial operation in 2006 and have mainly been used in acetate technology (e.g., MTBE production) and hydrogenation (Moritz and Gorak, 2002; Harmsen, 2007). Various research institutes and technology developers aim at developing new applications of reactive distillation. In the United States, a reactive distillation process for isomerization to produce clean high-octane isomerate is developed (U.S. DOE-OIT, 2001b). In Europe, a collaborative project of suppliers and universities aims to improve understanding of reactive distillation and develop simulation tools to design new applications. Other new developments include the use of monolithic structures that contain the catalysts, resulting in reduced catalyst loss and a low pressure drop (Babbich and Moulijn, 2003).

Advanced low fouling heat exchanger. While still in development, an advanced low fouling heat exchanger is a self-cleaning design that minimizes fouling on crude oil preheaters. It applies a self-cleaning mechanism by circulating cleaning particles through the tubes that handle the fouling process streams. According to Klaren et al. (2007), one of the low fouling heat exchangers designs reduces fouling from 100% (fouling rate set at 100% for conventional design) in the conventional design to 4% in the low fouling exchanger. The cost savings from replacing conventional heat exchangers on a typical 100,000 bpd refinery crude oil preheat train with low fouling heat exchangers will be about $13 million. This technology has not yet been proven in petroleum refining.

Advanced hydrotreater. An advanced hydrotreater process with “self-heat recuperation” is reported to yield significant energy savings (Matsuda et al., 2010). The feed stream to the heat exchanger is set at lower pressure than in the conventional process (i.e., conventional processes compress hydrogen before it enters the heat exchanger), thereby lowering the boiler temperature of the feed. When the surface area of the heat exchanger is increased, the feed stream will be heated and vaporized completely in the heat exchanger by the hydrotreater effluent heat. The stream is subsequently compressed to increase both stream pressure and temperature, enabling the reactor inlet pressure in the advanced process to remain the same as in the conventional process. The result is redundancy of the fired heater used in conventional processes, as the heat of the reactor effluent stream is used to completely preheat and vaporize the feed stream. In the advanced process, all the heat of the process stream is recirculated within the process, resulting in a 46% (74 TJ/yr) reduction in energy consumed in the hydrotreater (Matsuda et al., 2010).

20. Additional GHG Abatement Opportunities

Energy conservation is generally economically the most attractive way to reduce GHG emissions from the refining industry. Other GHG abatement opportunities exist for refineries beyond the energy conservation measures discussed in this Guide. Such additional GHG abatement opportunities are outlined in this section.

Carbon capture and sequestration (CCS). Carbon capture and sequestration may complement energy savings options in reducing GHG emissions from refineries. The principle of CCS is that CO_2 is captured and stored in geological formations for long periods of time (i.e., thousands of years). The three main technologies considered for CO_2 capture are post-combustion capture, pre-combustion capture, and oxyfuel combustion.

In petroleum refineries, CO_2 is emitted from a number of different processes, which are scattered across the facility. About 50% of total refinery CO_2 emissions come from a large number of low-concentration sources with a high CO_2 capture cost. The consideration of CO_2 capture at a refinery would therefore likely be limited to the larger CO_2 emitting stacks, such as FCC, large stacks from furnaces and gas turbines, and off-gas from the refinery's utilities plant, which typically make up between 30% and 50% of a refinery's CO_2 emissions. High pressure, high concentration CO_2 sources, such as the hydrogen production units, comprise 5% to 20% of CO_2 emissions and are another potential source for emissions reductions (van Straelen et al., 2010). Although CO_2 emissions are significantly reduced, the addition of CO_2 capture will require a considerable amount of additional energy and utilities, increasing the total quantity of emissions to be captured.

Various studies have estimated costs for CO_2 capture in petroleum refineries for both retrofit and newly built units. In the United States, the deployment potential of CO_2 capture in petroleum refineries is mainly in retrofits, because of limited growth in new refinery capacity. A study by Shell reports costs for post-combustion capture from refinery flue gases (i.e., from both combined stacks and FCC) in the range of \$120 to \$160/t CO_2 avoided (published as €90 to €120/t CO_2 avoided). Capture from the hydrogen production gasifier can be performed at significantly lower costs (\$40/t CO_2 avoided) due to the highly concentrated CO_2 stream (van Straelen et al., 2010). Other studies that reviewed available literature on costs for capture report CO_2 capture costs from specific process units. Capture of CO_2 from only the fluid catalytic cracker unit is reported to range from \$95 to \$140/t CO_2 avoided for post-combustion capture and \$73/t CO_2 avoided for oxyfuel capture technology. For CO_2 capture from the combined stack (i.e., refinery heaters and boilers) values vary from \$103 to \$157/t CO_2 avoided for post-combustion capture and a \$59 to \$73/t CO_2 for pre-combustion capture and oxyfuel technologies (DNV, 2010; Kuramochi et al., 2012).

A number of CCS projects at refineries have been initiated worldwide, although some have been delayed or cancelled for different reasons (e.g., Mongstad, Norway and Rotterdam, the Netherlands). In the United States, the U.S. Department of Energy funded a number of CCS projects, including three projects in petroleum refineries. CCS is demonstrated at the IGCC plant of ConocoPhillips' Houston, Texas refinery, the hydrogen production gasifier at the BP refinery in Denbury, Texas, and the Air Products steam methane reformer located at Valero's Port Arthur, Texas refinery. The CO_2 captured at these sites is used for enhanced oil recovery (U.S. DOE-OIT, 2009).

Fuel switching. Substantial amounts of CO_2, SO_2 and NOx emissions are produced in fired boilers and furnaces, especially when heavy fuel oil or other high CO_2 emitting fuels are used. Replacing the use of the liquid refinery fuels with refinery gas, LPG (often produced on-site), or natural gas (external supply) results in a reduction of CO_2, SO_2, and NOx emissions. In addition, as a result of the low SO_2 concentration in flue gases, the emission temperature at the stack can be lowered to 302°F (150°C), improving energy efficiency while lowering CO_2 emissions (IPPC, 2010). It should be noted that fuel switching to gas may result in a larger surplus of residue. Burning of the residue outside the refinery's boundaries only results in a shift of emissions and does not contribute to a reduction of global greenhouse gas emissions. Another option for these heavy residues is the conversion into lighter products, though this requires additional energy and related CO_2 emissions (IPPC, 2010).

Renewable energy. Replacing fossil fuels with renewable energy sources has the potential to reduce CO_2 emissions from petroleum refineries. Renewable energy can be used in various processing units and utility systems. For instance, biomass can be used for fuelling heaters, utilities, and for hydrogen production processes. Other renewable energy sources that can be considered for refinery applications include wind, solar, and geothermal energy. According to the American Petroleum Institute (API), from 2000 to 2007 approximately $188 billion was invested in emerging energy technologies for the U.S. oil and gas industry, of which $30 billion was invested in non-hydrocarbon technologies. The largest investments in non-hydrocarbon technologies were in wind, solar, and geothermal energy (Tanton et al., 2008).

Shell's Equilon refinery in Martinez, California, has installed a solar-powered circulator which aerates the wastewater treatment ponds. This solar-powered circulator, called SolarBee, replaced diesel-powered brush aerators. The alternative of powering the site from the grid was not economical because of the remote location of the pond. About $10,000 per year is saved on energy costs with the solar-powered system.

Valero completed the construction of a 10 MW wind farm near their McKee refinery in Sunray, Texas, in 2009. This wind farm has been expanded from six to 33 turbines, and currently has the capacity to generate 50 MW.

Coker - Decoking venting practices. After the quench period of the decoking cycle, a coke drum vent is opened to allow the drum to return to atmospheric pressure. The decoking steam vent is potentially a significant emission source of methane and VOCs. Decoking, including purging, cooling, venting, cutting the coke out, and preheating the coke drum before it goes back online takes between 16 and 24 hours. In order to increase coker throughput, cycle times are reduced by depressurizing the coke drum at higher temperatures and pressures; however, this leads to increased emissions. Cycle times shorter than 16 hours should be avoided as this indicates that the quenching cycle may be too short, leading to excessive and unnecessary methane and VOC emissions (U.S. EPA, 2010).

21. Water management

Similar to the identification of energy efficiency opportunities, water pinch studies can be carried out to identify options for water integration between processes, water reduction, and water reuse. The water usage of a refinery depends on both its purpose and complexity and is used as process water and for cooling purposes. Refineries use between 1 and 2.5 gallons of water for every gallon of product. A study of European refineries indicated that fresh water usage in refineries ranges from 0.7 to 28 million tonnes per year, with an average of 4.2 million tonnes/year (IPPC, 2010). Water has historically been viewed as a low-cost resource for refineries. As standards and costs for wastewater treatment increase, and costs for feedwater makeup rise, water use has become a more pressing concern. Furthermore, water efficiency is important for refineries as high quality fresh water is a valuable resource rapidly increasing in scarcity. There are various opportunities for reducing water consumption and increasing reuse in refineries, which will reduce the size and costs of water make-up and waste water treatment facilities and will lower the energy and chemical use.

Water stream integration. The purpose of water stream integration (WSI) is to reduce water use and minimize the amount of waste water produced that has to be treated before discharge. High-quality and demineralised potable water is saved, which can be quite expensive at some places. Furthermore, the size and environmental impact of the effluent discharge is reduced. Ideally, the treated effluent is used as the source for the make-up of process water, cooling water, and boiler feed water. Some opportunities to minimize fresh water consumption in refineries are (IPPC, 2010):

- Substituting wet cooling processes by dry processes.
- Recirculation of cooling water.
- Use of treated process water as cooling water.
- Use of condensates as process water.
- Use of rainwater as process water.

Reuse of treated water in the refinery. In 2000, the BP Carson refinery in Los Angeles, California, began using recycled water for cooling towers when their wells began to foul and lose yield. A reverse osmosis plant began operating in 2007 to make boiler feedwater from recycled water. This increased the share of recycled water use to 31% of total water use. BP anticipates using 90% recycled water by 2013.

In recent years there has been growing interest in the integration of ultrafiltration (UF) and reverse osmosis (RO) membrane technologies for waste water reuse in refineries. In a system with UF followed by RO, the UF can remove the suspended and colloidal material, bacteria, viruses and organic compounds, while the reverse osmosis removes dissolved salts. Since 2000, more than 20 UF and UF/RO systems have been installed at petrochemical facilities throughout the world for water reuse. The first reported successful full-scale use of integrated UF/RO membranes for in-plant water reclamation in a petrochemical facility is the China American Petrochemical Company (CAPCO) purified terephthatic acid (PTA) plant in Taiwan. Other large-scale applications of UF/RO are at the PEMEX refinery in Minatitlan, Mexico, and the Eni refinery in Gela, Italy. There have been, however, some unsuccessful installations due to problems with fouling and scaling of the membrane system. It is therefore recommended to conduct pilot studies to ensure proper selection and design of treatment technologies prior to implementing full-scale projects, unless there is operating experience from other facilities with similar characteristics and operating conditions (Wong, 2012).

Reuse of water in the desalter. The desalting process plays an important role in waste water management for a refinery. The wash water used in desalters typically comprises 5% to 8% of the crude throughput (IPIECA, 2010). The water that is used in other processes can be reused in the desalter. In this way, the refinery can reduce the consumption of water and reduce the hydraulic loading of the waste water treatment units. When reusing water, the formation of emulsions should be avoided, as it results in deterioration of the oil/water phase separation in the desalter. For instance, the effluents of the bitumen blowing units, hydrocrackers, cokers, and other deep conversion facilities may form emulsions. The applicability of water reuse in the desalter may be limited for existing refineries (IPPC, 2010).

Reuse of water in the coker. The water used for coke cutting and cooling in the decoking cycle of the coke drum is continuously recirculated, with a bleed-off, to the waste water treatment unit of the refinery. Settling and filtering the water over a vacuum filter allows the reuse of this water. For water make-up for the decoking process, different effluent streams from the refinery can be used; however, it is best to reuse water used for decoking in other refinery processes because of potential solids in the effluent (IPPC, 2010). Optimization of the water reuse in the coking process should be part of the water management system of the refinery.

22. Summary and Conclusions

Petroleum refining in the United States is the largest in the world, providing inputs to virtually every economic sector, including the transport sector and the chemical industry. As of 2012, the industry operates 144 refineries across the country, employing over 63,000 employees. The refining industry produces a mix of products with a total value exceeding $555 billion. Energy costs represents one the largest production cost factors in the petroleum refining industry, making energy efficiency improvement an important way to reduce costs and increase predictable earnings, especially in times of high energy-price volatility.

Voluntary government programs aim to assist industry in improving competitiveness through increased energy efficiency and reduced environmental impact. ENERGY STAR®, a voluntary program managed by the U.S. Environmental Protection Agency, stresses the need for strong and strategic corporate energy management programs. ENERGY STAR provides energy management tools and strategies for successful corporate energy management programs. The current report describes research conducted to support ENERGY STAR and its work with the petroleum refining industry. This research provides information on potential energy efficiency opportunities for petroleum refineries.

Competitive benchmarking data indicates that most petroleum refineries can economically improve energy efficiency by between 10% and 20%. These potential improvements may amount to annual costs savings of millions to tens of millions of dollars for a refinery, depending on its current efficiency and size. Improved energy efficiency may also result in co-benefits that far outweigh the energy cost savings, and may lead to an absolute reduction in emissions.

This Guide introduced energy efficiency opportunities available for petroleum refineries. It provides descriptions of the production trends, structure and production of the refining industry and the energy used in the refining and conversion processes. Where available, this Guide provided specific energy savings for each energy efficiency measure based on case studies of plants and references to technical literature. The Guide draws upon the experiences of worldwide petroleum refineries with energy efficiency measures. If available, typical payback periods were also listed. Finally, it discussed some additional GHG abatement technologies and opportunities for water management in U.S. refineries.

Given the available resources and technology, there are significant opportunities to cost-effectively reduce energy consumption in the petroleum refining industry, while maintaining the quality of the products manufactured. Further research on the economics of the measures, as well as the applicability of these to different refineries, is needed to assess the feasibility of implementation of selected technologies at individual plants. Tables 8 and 9 summarize the energy efficiency opportunities for petroleum refineries. Table 10 lists the additional GHG abatement technologies and water management opportunities identified.

Table 8. Summary of energy efficiency opportunities for utilities and cross-cutting energy uses.

Energy Management and Control (Chapter 6)	
Energy management systems (EMS) and programs Energy monitoring and control systems	Energy teams
Energy Recovery (Chapter 7)	
Flare gas recovery	Power recovery
Steam Generation and Distribution (Chapter 8)	
Boilers	
Boiler feedwater preparation Improve boiler process control Reduction of flue gas quantities Reduction of excess air Improve insulation Boiler maintenance	Burner replacement Condensate return Flue gas heat recovery Minimize boiler blowdown Blowdown steam recovery
Steam Distribution Systems	
Steam distribution controls Improve insulation Insulation maintenance Steam trap improvement	Steam trap maintenance Steam trap automatic monitoring Leak repair Flash steam recovery
Heat Exchangers and Process Integration (Chapter 9)	
Heat Exchangers	
Fouling control	
Process Integration	
Total site pinch analysis	

Heaters and Furnaces (Chapter 10)	
Maintenance – draft control Air preheating	New burners
Distillation (Chapter 11)	
Optimize operation procedures Optimize product purity Seasonal operating pressure adjustments Reduce reboiler duty Upgrade column internals	Stripper optimization Progressive crude distillation Dividing-wall column Install liquid-ring vacuum pump
Hydrogen Management and Recovery (Chapter 12)	
Hydrogen integration	Hydrogen recovery
Hydrogen Production	
Adiabatic pre-reformer Integrated gasification combined cycle (IGCC)	Reformer combustion air and feed preheat
Motor Systems (Chapter 13)	
Motor management plan Strategic motor selection Motor system maintenance Properly sized motors	Adjustable-speed drives (ASDs) Power factor correction Minimizing voltage unbalance
Pump Systems (Chapter 14)	
Pump system maintenance Pump system monitoring Reduction of pump demand Pump system controls High-efficiency pumps Properly sized pumps	Impeller trimming Avoiding throttling valves Replacement of belt drives Proper pipe sizing Precision casting, surface coating or polishing Sealings

Pump Systems (Chapter 14) (continued)	
Multiple pumps for variable loads Adjustable-speed drives (ASDs)	Curtailing leakages through clearance reduction
Compressors and Compressed Air (Chapter 15)	
System improvements	Improved load management
Compressed air maintenance	Pressure drop minimization
Compressed air system monitoring	Inlet air temperature reduction
Leak reduction	Compressed air system controls
Turning off unnecessary compressed air	Properly sized pipe diameter
Modification of system in lieu of increased pressure	Heat recovery
Replacement by alternative sources	Natural gas engine-driven compressors
Fan Systems (Chapter 16)	
Maintenance	High efficiency belts (cog belts)
Properly sized fans	Duct leakage repair
ASDs and improved control	
Lighting (Chapter 17)	
Turning off lights in unoccupied areas	Replacement of mercury lamps
Lighting controls	High-intensity discharge (HID) voltage reduction
Exit signs	High-intensity fluorescent lights
Electronic ballasts	LED lighting
Replacement of T-12 tubes with T-8 tubes	Daylighting
Power Generation (Chapter 18)	
Combined heat and power generation (CHP)	Turbine pre-coupling
Gas expansion turbines	Gasification

Power Generation (Chapter 18) (continued)	
Steam expansion turbines	
Other opportunities (Chapter 19)	
Process changes and design	
Alternative desalter designs Reformer increased product recovery Slurry-phase hydrocracking technology	Saturated gas plant Coke drum blowdown system
Alternative production flows	
FCC process flow changes	
Other opportunities	
Flare optimization	Heated storage tanks
Innovative technologies	
Improved delayed coking Internal heat-integrated distillation column Membranes	Alternative desulfurization Biodesulfurization Reactive distillation

Table 9. Summary of process-specific energy efficiency opportunities.

Desalter	
Multi-stage desalter	Combined AC/DC fields
CDU	
Process controls	Progressive crude distillation
Turbine pre-coupling	Internal heat-integrated distillation column
Process integration (pinch)	Liquid-ring vacuum pump
Furnace controls	Membranes
Air preheating	Reduce reboiler duty
Dividing-wall column	Upgrade column internals
Distillation optimization	Seasonal operating pressure adjustments
VDU	
Process controls	Air preheating
Process integration (pinch)	Distillation optimization
Furnace controls	
Hydrotreater	
Process controls	Alternative desulfurization
Process integration (pinch)	Biodesulfurization
Distillation optimization	Hydrogen recovery
Catalytic Reformer	
Process integration (pinch)	Distillation optimization
Furnace controls	Increased product recovery
Air preheating	
FCC	
Process controls	Air preheating
Power recovery	Distillation optimization

FCC (continued)	
Process integration (pinch) Furnace controls Hydrogen recovery	Process flow changes Reactive distillation
Hydrocracker	
Power recovery Process integration (pinch) Furnace controls Hydrogen recovery	Air preheating Distillation optimization Slurry-phase hydrocracker Reactive distillation
Coker	
Process integration (pinch) Furnace controls Air preheating	Improved delayed coking Coke drum blowdown system
Visbreaker	
Process integration (pinch)	Distillation optimization
Alkylation	
Process controls Process integration (pinch)	Distillation optimization
Hydrogen Production	
Process integration (pinch) Furnace controls Air preheating Adiabatic pre-reformer	Integrated gasification combined cycle (IGCC) Turbine pre-coupling (steam methane reformer) Reformer combustion air and feed preheat
Other	
Flare optimization	Heated storage tanks

Table 10. Summary of opportunities to reduce GHG emissions and water use in refineries

Greenhouse gas emissions	
Carbon capture and sequestration (CCS) Fuel switching	Renewable energy Decoking venting practices
Water use	
Water stream integration Reuse of treated water in the refinery	Reuse of water in desalter Reuse of water in coker

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Appendix A: Active refineries in the U.S. as of January 2012

Company	Site	State	Capacity (b/cd)	Share	Company - Total (b/cd)	Share company
Alon Israel Oil Company LTD	Big Spring	Texas	67,000	0.4%	147,000	0.8%
	Krotz Springs	Louisiana	80,000	0.5%		
American Refining Group Inc.	Bradford	Pennsylvania	10,000	0.1%	10,000	0.1%
Big West Oil Co.	North Salt Lake	Utah	29,400	0.2%	29,400	0.2%
BP	Ferndale	Washington	225,000	1.3%	1,209,715	7.0%
	Los Angeles	California	240,000	1.4%		
	Prudhoe Bay	Alaska	6,935	0.0%		
	Texas City	Texas	400,780	2.3%		
	Whiting	Indiana	337,000	1.9%		
BP-Husky Refining LLC	Toledo	Ohio	135,000	0.8%	135,000	0.8%
Calcasieu Refining Co.	Lake Charles	Louisiana	78,000	0.5%	78,000	0.5%
Calumet Lubricants Co. LP	Superior	Wisconsin	38,000	0.2%	116,320	0.7%
	Cotton Valley	Louisiana	13,020	0.1%		
	Princeton	Louisiana	8,300	0.0%		
	Shreveport	Louisiana	57,000	0.3%		
Cenex Harvest States Coop	Laurel	Montana	59,600	0.3%	59,600	0.3%
Chalmette Refining LLC	Chalmette	Louisiana	192,500	1.1%	192,500	1.1%
Chevron U.S.A. Inc.	El Segundo	California	276,000	1.6%	1,030,271	5.9%
	Honolulu	Hawaii	54,000	0.3%		
	Pascagoula	Mississippi	330,000	1.9%		
	Perth Amboy	New Jersey	80,000	0.5%		
	Richmond	California	245,271	1.4%		
	Salt Lake City	Utah	45,000	0.3%		
CITGO Petroleum Corp	Corpus Christi	Texas	163,000	0.9%	590,800	3.4%

Company	Site	State	Capacity (b/cd)	Share	Company - Total (b/cd)	Share company
	Lake Charles	Louisiana	427,800	2.5%		
Coffeyville Resources RFG & MKTG LLC	Coffeyville	Kansas	115,700	0.7%	115,700	0.7%
ConocoPhillips	Belle Chasse	Louisiana	247,000	1.4%	1,602,000	9.2%
	Billings	Montana	58,000	0.3%		
	Ferndale	Washington	100,000	0.6%		
	Linden	New Jersey	238,000	1.4%		
	Ponca City	Oklahoma	198,400	1.1%		
	Prudhoe Bay	Alaska	15,000	0.1%		
	Rodeo	California	120,200	0.7%		
	Sweeny	Texas	247,000	1.4%		
	Westlake	Louisiana	239,400	1.4%		
	Wilmington	California	139,000	0.8%		
Continental Refining Company LLC	Somerset	Kentucky	5,500	0.0%	5,500	0.0%
Countrymark Cooperative Inc.	Mount Vernon	Indiana	26,500	0.2%	26,500	0.2%
Deer Park Refining Ltd Partnership	Deer Park	Texas	327,000	1.9%	327,000	1.9%
Delaware City Refining Co. LLC	Delaware City	Delaware	182,200	1.1%	182,200	1.1%
Delek Refining LTD	Tyler	Texas	60,000	0.3%	60,000	0.3%
Ergon Refining Inc.	Vicksburg	Mississippi	23,000	0.1%	43,000	0.2%
	Newell	West Virginia	20,000	0.1%		
ExxonMobil	Baton Rouge	Louisiana	502,500	2.9%	1,855,600	10.7%
	Baytown	Texas	560,500	3.2%		
	Beaumont	Texas	344,500	2.0%		
	Billings	Montana	60,000	0.3%		
	Joliet	Illinois	238,600	1.4%		

Company	Site	State	Capacity (b/cd)	Share	Company - Total (b/cd)	Share company
	Torrance	California	149,500	0.9%		
Flint Hills Resources LP	Corpus Christi	Texas	284,172	1.6%	781,529	4.5%
	North Pole	Alaska	220,157	1.3%		
	Saint Paul	Minnesota	277,200	1.6%		
Foreland Refining Corp.	Ely	Nevada	2,000	0.0%	2,000	0.0%
Frontier Refining Inc.	Cheyenne	Wyoming	47,000	0.3%	185,000	1.1%
	El Dorado	Kansas	138,000	0.8%		
Garco Energy LLC	Douglas	Wyoming	3,000	0.0%	3,000	0.0%
Goodway Refining LLC	Atmore	Alabama	4,100	0.0%	4,100	0.0%
Holly Refining & Marketing Co.	Tulsa East	Oklahoma	70,300	0.4%	180,350	1.0%
	Tulsa West	Oklahoma	85,000	0.5%		
	Woods Cross	Utah	25,050	0.1%		
Houston Refining LP	Houston	Texas	273,433	1.6%	273,433	1.6%
Hunt Refining Co.	Sandersville	Mississippi	11,000	0.1%	47,000	0.3%
	Tuscaloosa	Alabama	36,000	0.2%		
Kern Oil & Refining Co.	Bakersfield	California	26,000	0.2%	26,000	0.2%
Lazarus Energy LLC	Nixon	Texas	9,589	0.1%	9,589	0.1%
Lima Refining Company	Lima	Ohio	155,000	0.9%	155,000	0.9%
Lion Oil Co.	El Dorado	Arkansas	83,000	0.5%	83,000	0.5%
Little America Refining Co.	Evansville	Wyoming	24,500	0.1%	24,500	0.1%
Lunday Thagard Co.	South Gate	California	8,500	0.0%	8,500	0.0%
Marathon Petroleum Co. LLC	Canton	Ohio	78,000	0.5%	1,193,000	6.9%
	Catlettsburg	Kentucky	233,000	1.3%		
	Detroit	Michigan	106,000	0.6%		
	Garyville	Louisiana	490,000	2.8%		
	Robinson	Illinois	206,000	1.2%		
	Texas City	Texas	80,000	0.5%		

Company	Site	State	Capacity (b/cd)	Share	Company - Total (b/cd)	Share company
Martin Midstream Partners LP	Smackover	Arkansas	7,500	0.0%	7,500	0.0%
Montana Refining Co.	Great Falls	Montana	10,000	0.1%	10,000	0.1%
Motiva Enterprises LLC	Convent	Louisiana	235,000	1.4%	753,500	4.3%
	Norco	Louisiana	233,500	1.3%		
	Port Arthur	Texas	285,000	1.6%		
Navajo Refining Co.	Artesia	New Mexico	105,000	0.6%	105,000	0.6%
NCRA	McPherson	Kansas	85,500	0.5%	85,500	0.5%
Nustar Asphalt Refining LLC	Paulsboro	New Jersey	70,000	0.4%	112,021	0.6%
	San Antonio	Texas	14,021	0.1%		
	Savannah	Georgia	28,000	0.2%		
Paramount Petroleum Corp.	Paramount	California	84,500	0.5%	84,500	0.5%
Pasadena Refining Systems Inc.	Pasadena	Texas	100,000	0.6%	100,000	0.6%
Paulsboro Refining Co. LLC	Paulsboro	New Jersey	160,000	0.9%	160,000	0.9%
PDV Midwest Refining LLC	Lemont	Illinois	167,000	1.0%	167,000	1.0%
Petro Star Inc.	North Pole	Alaska	19,700	0.1%	74,700	0.4%
	Valdez	Alaska	55,000	0.3%		
Placid Refining Co.	Port Allen	Louisiana	57,000	0.3%	57,000	0.3%
Premcor Refining Group Inc.	Memphis	Tennessee	180,000	1.0%	470,000	2.7%
	Port Arthur	Texas	290,000	1.7%		
San Joaquin Refining Co. Inc.	Bakersfield	California	15,000	0.1%	15,000	0.1%
Santa Maria Refining Company	Santa Maria	California	9,500	0.1%	9,500	0.1%
Shell	Anacortes	Washington	145,000	0.8%	436,400	2.5%
	Martinez	California	156,400	0.9%		
	Saint Rose	Louisiana	55,000	0.3%		
	Saraland	Alabama	80,000	0.5%		
Silver Eagle Refining	Evanston	Wyoming	3,000	0.0%	13,250	0.1%
	Woods Cross	Utah	10,250	0.1%		

Company	Site	State	Capacity (b/cd)	Share	Company - Total (b/cd)	Share company
Sinclair Oil Corp.	Sinclair	Wyoming	74,000	0.4%	74,000	0.4%
St. Paul Park Refining Co. LLC	Saint Paul	Minnesota	74,000	0.4%	74,000	0.4%
Suncor Energy Inc.	Commerce City East	Colorado	36,000	0.2%	103,000	0.6%
	Commerce City West	Colorado	67,000	0.4%		
Sunoco Inc.	Philadelphia	Pennsylvania	335,000	1.9%	335,000	1.9%
Tesoro	Anacortes	Washington	120,000	0.7%	668,800	3.9%
	Ewa Beach	Hawaii	93,500	0.5%		
	Kenai	Alaska	68,000	0.4%		
	Mandan	North Dakota	60,000	0.3%		
	Martinez	California	166,000	1.0%		
	Salt Lake City	Utah	57,500	0.3%		
	Wilmington	California	103,800	0.6%		
Toledo Refining Co. LLC	Toledo	Ohio	160,000	0.9%	160,000	0.9%
Total Petrochemicals Inc.	Port Arthur	Texas	225,500	1.3%	225,500	1.3%
United Refining Co.	Warren	Pennsylvania	65,000	0.4%	65,000	0.4%
U.S. Oil & Refining Co.	Tacoma	Washington	40,700	0.2%	40,700	0.2%
Valero Energy Corp.	Ardmore	Oklahoma	85,000	0.5%	1,393,300	8.0%
	Benicia	California	132,000	0.8%		
	Corpus Christi	Texas	200,000	1.2%		
	Houston	Texas	88,000	0.5%		
	Meraux	Louisiana	125,000	0.7%		
	Norco	Louisiana	205,000	1.2%		
	Sunray	Texas	156,000	0.9%		
	Texas City	Texas	225,000	1.3%		
	Three Rivers	Texas	93,000	0.5%		
	Wilmington Asphalt Plant	California	6,300	0.0%		
	Wilmington Refinery	California	78,000	0.5%		

Company	Site	State	Capacity (b/cd)	Share	Company - Total (b/cd)	Share company
Ventura Refining & Transmission LLC	Thomas	Oklahoma	12,000	0.1%	12,000	0.1%
Western Refining Inc.	Bloomfield	New Mexico	16,800	0.1%	159,900	0.9%
	El Paso	Texas	122,000	0.7%		
	Gallup	New Mexico	21,100	0.1%		
WRB Refining LLC	Borger	Texas	146,000	0.8%	474,000	2.7%
	Wood River	Illinois	328,000	1.9%		
Wynnewood Refining Co.	Wynnewood	Oklahoma	70,000	0.4%	70,000	0.4%
Wyoming Refining Co.	New Castle	Wyoming	14,000	0.1%	14,000	0.1%

Appendix B: Basic Energy Efficiency Actions for Plant Personnel

Personnel at all levels should be aware of energy use and organizational goals for energy efficiency. Staff should be trained in both skills and general approaches to energy efficiency in day-to-day practices. In addition, performance results should be regularly evaluated and communicated to all personnel, recognizing high achievement. Some examples of simple tasks employees can do are outlined below (Caffal, 1995).

- Eliminate unnecessary energy consumption by equipment. Switch off motors, fans, and machines when they are not being used, especially at the end of the working day or shift, and during breaks, when it does not affect production, quality, or safety. Similarly, turn on equipment no earlier than needed to reach the correct settings (temperature, pressure) at the start time.
- Switch off unnecessary lights; rely on daylight whenever possible.
- Use weekend and night setbacks on HVAC in offices or conditioned buildings.
- Report leaks of water (both process water and dripping taps), steam, and compressed air. Ensure they are repaired quickly. The best time to check for leaks is a quiet time like the weekend.
- Look for unoccupied areas being heated or cooled, and switch off heating or cooling.
- Check that heating controls are not set too high or cooling controls set too low. In this situation, windows and doors are often left open to lower temperatures instead of lowering the heating.
- Check to make sure the pressure and temperature of equipment is not set too high.
- Prevent drafts from badly fitting seals, windows and doors, and hence, leakage of cool or warm air.
- Carry out regular maintenance of energy-consuming equipment.
- Ensure that the insulation on process heating equipment is effective.

Appendix C: Energy Management System Assessment for Best Practices in Energy Efficiency

	ORGANIZATION		SYSTEMS MONITORING		TECHNOLOGY		O & M
	Accountability	**Organization**	**Monitoring & Targeting**	**Utilities Management**	**Reviews**	**Plans**	**Operation & Maintenance**
0	No awareness of responsibility for energy usage. Energy not specifically discussed in meetings.	No energy manager or "energy champion."	Energy efficiency of processes on site not determined. Few process parameters monitored regularly.	No utilities consumption monitoring.	No specific reviews held.	No energy improvement plans published.	No written procedures for practices affecting energy efficiency.
1	Operations staff aware of the energy efficiency performance objective of the site.	Energy manager is combined with other tasks and roles such that less than 10% of one person's time is given to specific energy activities.	Energy efficiency of site determined monthly or yearly. Site annual energy efficiency target set. Some significant process parameters are monitored.	Utilities (like power and fuel consumption) monitored on overall site basis.	Energy only reviewed as part of other type reviews	Energy improvement plans published but based on an arbitrary assessment of opportunities.	No procedures available to operating staff.
2	Energy efficiency performance indicators are produced and available to operations staff. Periodic energy campaigns. Intermittent energy review meetings.	Energy manager appointed giving greater than 10% of time to task. Occasional training in energy related issues.	Weekly trend monitoring of energy efficiency of processes and of site, monitored against targets. Process parameters monitored against target.	Weekly monitoring of steam/power balance.	Infrequent energy review.	Energy performance plan published based on estimate of opportunities.	Procedures available to operators but not recently reviewed.

	ORGANIZATION		SYSTEMS MONITORING		TECHNOLOGY		O & M
	Accountability	**Organization**	**Monitoring & Targeting**	**Utilities Management**	**Reviews**	**Plans**	**Operation & Maintenance**
3	Energy efficiency performance parameter determined for all energy consuming areas. Operations staff advised of performance. All employees aware of energy policy. Performance review meetings held once/month.	Energy manager in place greater than 30% of time given to task. Ad-hoc training arranged. Energy performance reported to management.	Daily trend monitoring of energy efficiency of processes and of site, monitored against target. Process parameters monitored against targets.	Daily monitoring of steam/power. Steam & fuel balances adjusted daily.	Regular plant/site energy reviews carried out.	A five-year energy improvement plan is published based on identified opportunities from energy review.	Procedures available to operators and reviewed in the last three years.
4	Energy efficiency performance parameter included in personal performance appraisals. All staff involved in site energy targets and improvement plans. Regular weekly meeting to review performance.	An energy manager is in place giving greater than 50% time to task. Energy training to take place regularly. Energy performance reported to management and actions followed up.	Same as 3, with additional participation in energy efficiency target setting. Process parameters trended.	Real time monitoring of fuel, steam and steam/power balance. Optimum balances maintained.	Site wide energy studies carried out at least every five years with follow up actions progressed to completion	A ten year energy improvement plan based on review is published and integrated into the Business Plan.	Procedures are reviewed regularly and updated to incorporate the best practices. Used regularly by operators and supervisors.

Appendix D: Guidelines for Energy Management Assessment Matrix

CHANGE FOR THE BETTER WITH ENERGY STAR

Energy Management Program Assessment Matrix

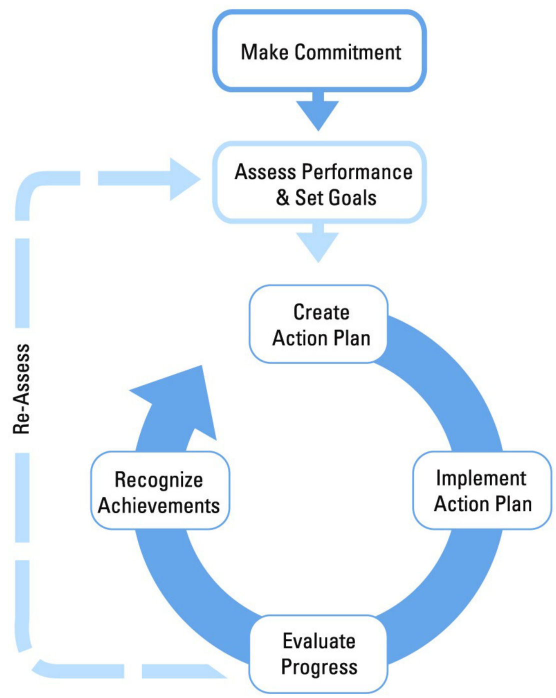
Introduction

The U.S. EPA has developed guidelines for establishing and running an effective energy management program based on the successful practices of ENERGY STAR partners.

These guidelines, illustrated in the graphic, are structured on seven fundamental management elements that encompass specific activities.

This assessment matrix is designed to help organizations and energy managers compare their energy management practices to those outlined in the Guidelines. The full Guidelines can be viewed on the ENERGY STAR website www.energystar.gov

ENERGY STAR Guidelines for Energy Management



How to use the assessment matrix

The matrix outlines the key activities identified in the ENERGY STAR Guidelines for Energy Management and three levels of implementation:

- Little or no evidence
- Some elements
- Fully Implemented

1. Print the assessment matrix.
2. Compare your program to the Guidelines by identifying the degree of implementation that most closely matches your organization's program.
3. Use a highlighter to fill in the cell that best characterizes the level of implementation of your program. You will now have a visual comparison of your program to the elements of the ENERGY STAR Guidelines for Energy Management.
4. Identify the steps needed to fully implement the energy management elements and record these in the Next Steps column.

Interpreting your results

Comparing your program to the level of implementation identified in the matrix should help you identify the strengths and weaknesses of your program.

The U.S. EPA has observed that organizations fully implementing the practices outlined in the Guidelines achieve the greatest results. Organizations are encouraged to implement the Guidelines as fully as possible.

By highlighting the cells of the matrix, you now can easily tell how well balanced your energy program is across the management elements of the Guidelines. Use this illustration of your energy management program for discussion with staff and management.

Use the "Next Steps" column of the Matrix to develop a plan of action for improving your energy management practices.

Resources and help

ENERGY STAR offers a variety of tools and resources to help organizations strengthen their energy management programs.

Here are some next steps you can take with ENERGY STAR:

1. Read the Guidelines sections for the areas of your program that are not fully implemented.

2. Become an ENERGY STAR Partner, if you are not already.

3. Review ENERGY STAR Tools and Resources.

4. Find more sector-specific energy management information at www.energystar.gov/industry.

5. Contact ENERGY for additional resources.

ENERGY STAR Guidelines For Energy Management Assessment Matrix

	Little or no evidence	Some elements	Fully implemented	Next steps
Make Commitment to Continuous Improvement				
Energy Director	No central corporate resource Decentralized management	Corporate resource not empowered	Empowered corporate leader with senior management support	
Energy Team	No company energy network	Informal organization	Active cross-functional team guiding energy program	
Energy Policy	No formal policy	Referenced in environmental or other policies	Formal stand-alone EE policy endorsed by senior mgmt.	
Assess Performance and Opportunities				
Gather and Track Data	Little metering/no tracking	Local or partial metering/tracking/reporting	All facilities report for central consolidation/analysis	
Normalize	Not addressed	Some unit measures or weather adjustments	All meaningful adjustments for corporate analysis	
Establish baselines	No baselines	Various facility-established	Standardized corporate base year and metric established	
Benchmark	Not addressed or only same site historical comparisons	Some internal comparisons among company sites	Regular internal & external comparisons & analyses	
Analyze	Not addressed	Some attempt to identify and correct spikes	Profiles identifying trends, peaks, valleys & causes	
Technical assessments and assessments	Not addressed	Internal facility reviews	Reviews by multi-functional team of professionals	
Set Performance Goals				
Determine scope	No quantifiable goals	Short term facility goals or nominal corporate goals	Short & long term facility and corporate goals	
Estimate potential for improvement	No process in place	Specific projects based on limited vendor projections	Facility & corporate defined based on experience	

Establish goals	Not addressed	Loosely defined or sporadically applied	Specific & quantifiable at various organizational levels	
Create Action Plan				
Define technical steps and targets	Not addressed	Facility-level consideration as opportunities occur	Detailed multi-level targets with timelines to close gaps	
Determine roles and resources	Not addressed	Informal interested person competes for funding	Internal/external roles defined & funding identified	
Implement Action Plan				
Create a communication plan	Not addressed	Tools targeted for some groups used occasionally	All stakeholders are addressed on regular basis	
Raise awareness	No overt effort made	Periodic references to energy initiatives	All levels of organization support energy goals	
Build capacity	Indirect training only	Some training for key individuals	Broad training/certification in technology & best practices	
Motivate	Occasional mention	Threats for non-performance or periodic reminders	Recognition, financial & performance incentives	
Track and monitor	No system for monitoring progress	Annual reviews by facilities	Regular reviews & updates of centralized system	
Evaluate Progress				
Measure results	No reviews	Historical comparisons	Compare usage & costs vs. goals, plans, competitors	
Review action plan	No reviews	Informal check on progress	Revise plan based on results, feedback & business factors	
Recognize Achievements				
Provide internal recognition	Not addressed	Identify successful projects	Acknowledge contributions of individuals, teams, facilities	
Get external recognition	Not sought	Incidental or vendor acknowledgement	Government/third party highlighting achievements	

Appendix E: Teaming Up to Save Energy Checklist

The following checklist can be used as a handy reference to key tasks for establishing and sustaining an effective energy team. For more detailed information on energy teams, consult the U.S. EPA's *Teaming Up to Save Energy* guide (U.S. EPA, 2006), which is available at http://www.energystar.gov/.

ORGANIZE YOUR ENERGY TEAM		√
Energy Director	Able to work with all staff levels from maintenance to engineers to financial officers. Senior-level person empowered by top management support	
Senior Management	Energy director reports to senior executive or to a senior management council. Senior champion or council provides guidance and support	
Energy Team	Members from business units, operations/engineering, facilities, and regions. Energy networks formed. Support services (PR, IT, HR).	
Facility Involvement	Facility managers, electrical personnel. Two-way information flow on goals and opportunities. Facility-based energy teams with technical person as site champion.	
Partner Involvement	Consultants, vendors, customers, and joint venture partners. Energy savings passed on through lower prices.	
Energy Team Structure	Separate division and/or centralized leadership. Integrated into organization's structure and networks established.	
Resources & Responsibilities	Energy projects incorporated into normal budget cycle as line item. Energy director is empowered to make decisions on projects affecting energy use. Energy team members have dedicated time for the energy program.	
STARTING YOUR ENERGY TEAM		√
Management Briefing	Senior management briefed on benefits, proposed approach, and potential energy team members.	
Planning	Energy team met initially to prepare for official launch.	
Strategy	Energy team met initially to prepare for official launch.	
Program Launch	Organizational kickoff announced energy network, introduced energy director, unveiled energy policy, and showcased real-world proof.	
Energy Team Plans	Work plans, responsibilities, and annual action plan established.	
Facility Engagement	Facility assessments and reports conducted. Energy efficiency opportunities identified.	

BUILDING CAPACITY		√
Tracking and Monitoring	Systems established for tracking energy performance and best practices implementation.	
Transferring Knowledge	Events for informal knowledge transfer, such as energy summits and energy fairs, implemented.	
Raising Awareness	Awareness of energy efficiency created through posters, intranet, surveys, and competitions.	
Formal Training	Participants identified, needs determined, training held. Involvement in ENERGY STAR Web conferences and meetings encouraged. Professional development objectives for key team members.	
Outsourcing	Use of outside help has been evaluated and policies established.	
Cross-Company Networking	Outside company successes sought and internal successes shared. Information exchanged to learn from experiences of others.	
SUSTAINING THE TEAM		√
Effective Communications	Awareness of energy efficiency created throughout company. Energy performance information is published in company reports and communications.	
Recognition and Rewards	Internal awards created and implemented. Senior management is involved in providing recognition.	
External Recognition	Credibility for your organization's energy program achieved. Awards from other organizations have added to your company's competitive advantage.	
MAINTAINING MOMENTUM		√
Succession	Built-in plan for continuity established. Energy efficiency integrated into organizational culture.	
Measures of Success	Sustainability of program and personnel achieved. Continuous improvement of your organization's energy performance attained.	

Appendix F: Support Programs for Industrial Energy Efficiency Improvement

This appendix provides a list of energy efficiency support available to industry. A brief description of the program or tool is given, as well as information on its target audience and the URL for the program. Included are federal and state programs. Use the URL to obtain more information from each of these sources. An attempt was made to provide as complete a list as possible; however, information in this listing may change with the passage of time.

Tools for Self-Assessment

Steam System Assessment Tool

Description:	Software package to evaluate energy efficiency improvement projects for steam systems. It includes an economic analysis capability.
Target Group:	Any industry operating a steam system
Format:	Downloadable software package (13.6 MB)
Contact:	U.S. Department of Energy
URL:	http://www1.eere.energy.gov/manufacturing/tech_deployment/software_ssat.html

Steam System Scoping Tool

Description:	Spreadsheet tool for plant managers to identify energy efficiency opportunities in industrial steam systems.
Target Group:	Any industrial steam system operator
Format:	Downloadable software (Excel)
Contact:	U.S. Department of Energy
URL:	http://www1.eere.energy.gov/manufacturing/tech_deployment/software_ssat.html

3E Plus®: Insulation Thickness Computer Program

Description:	Downloadable software to determine whether boiler systems can be optimized through the insulation of boiler steam lines. The program calculates the most economical thickness of industrial insulation for a variety of operating conditions. It

makes calculations using thermal performance relationships of generic insulation materials included in the software.

Target Group: Energy and plant managers

Format: Downloadable software

Contact: U.S. Department of Energy

URL: http://www1.eere.energy.gov/manufacturing/tech_deployment/software_ssat.html

MotorMaster+

Description: Energy-efficient motor selection and management tool, including a catalog of over 20,000 AC motors. It contains motor inventory management tools, maintenance log tracking, efficiency analysis, savings evaluation, energy accounting, and environmental reporting capabilities.

Target Group: Any industry

Format: Downloadable software (can also be ordered on CD)

Contact: U.S. Department of Energy

URL: http://www1.eere.energy.gov/manufacturing/tech_deployment/software_motormaster.html

The 1-2-3 Approach to Motor Management

Description: A step-by-step motor management guide and spreadsheet tool that can help motor service centers, vendors, utilities, energy-efficiency organizations, and others convey the financial benefits of sound motor management.

Target Group: Any industry

Format: Downloadable Microsoft Excel spreadsheet

Contact: Consortium for Energy Efficiency (CEE), (617) 589-3949

URL: http://www.motorsmatter.org/tools/123approach.html

AirMaster+: Compressed Air System Assessment and Analysis Software

Description: Modeling tool that maximizes the efficiency and performance of compressed air systems through improved operations and maintenance practices.

Target Group: Any industry operating a compressed air system

Format: Downloadable software

Contact: U.S. Department of Energy

URL:
http://www1.eere.energy.gov/manufacturing/tech_deployment/software_airmaster.html

Fan System Assessment Tool (FSAT)

Description: **The Fan System Assessment Tool (FSAT) helps to quantify the potential benefits of optimizing a fan system. FSAT calculates the amount of energy used by a fan system, determines system efficiency, and quantifies the savings potential of an upgraded system.**

Target Group: **Any user of fans**

Format: **Downloadable software**

Contact: **U.S. Department of Energy**

URL: http://www1.eere.energy.gov/manufacturing/tech_deployment/software_fsat.html

Combined Heat and Power Application tool (CHP)

Description: The Combined Heat and Power Application Tool (CHP) helps industrial users evaluate the feasibility of CHP for heating systems such as fuel-fired furnaces, boilers, ovens, heaters, and heat exchangers.

Target Group: Any industrial heat and electricity user

Format: Downloadable software

Contact: U.S. Department of Energy

URL: http://www1.eere.energy.gov/manufacturing/tech_deployment/software_chp.html

Pumping System Assessment Tool (PSAT)

Description: The tool helps industrial users assess the efficiency of pumping system operations. PSAT uses achievable pump performance data from Hydraulic Institute standards and motor performance data from the MotorMaster+ database to calculate potential energy and associated cost savings.

Target Group: Any industrial pump user

Format: Downloadable software

Contact: U.S. Department of Energy

URL: http://www1.eere.energy.gov/manufacturing/tech_deployment/software_psat.html

Plant Energy Profiler/Integrated Tool Suite

Description: The Plant Energy Profiler, or ePEP (formerly called Quick PEP), is an online software tool provided by the U.S. Department of Energy to help industrial plant managers in the United States identify how energy is being purchased and consumed at their plant and also identify potential energy and cost savings. ePEP is designed so that the user can complete a plant profile in about an hour. The ePEP online tutorial explains what plant information is needed to complete an ePEP case.

Target Group: Any industrial plant

Format: Online software tool

Contact: U.S. Department of Energy

URL: http://www1.eere.energy.gov/manufacturing/tech_assistance/printable_versions/software_epep.html

ENERGY STAR Portfolio Manager

Description: Online software tool helps to assess the energy performance of buildings by providing a 1-100 ranking of a building's energy performance relative to the national building market. Measured energy consumption forms the basis of the ranking of performance.

Target Group: Any building user or owner

Format: Online software tool

Contact: U.S. Environmental Protection Agency

URL: http://www.energystar.gov/index.cfm?c=evaluate_performance.bus_portfoliomanager

Assessment and Technical Assistance

Industrial Assessment Centers

Description: Small- to medium-sized manufacturing facilities can obtain a free energy and waste assessment. The audit is performed by a team of engineering faculty and students from 30 participating universities in the U.S. and assesses the plant's performance and recommends ways to improve efficiency.

Target Group: Small- to medium-sized manufacturing facilities with gross annual sales below $75 million and fewer than 500 employees at the plant site.

Format: A team of engineering faculty and students visits the plant and prepares a written report with energy efficiency, waste reduction and productivity recommendations.

Contact: U.S. Department of Energy

URL: http://www1.eere.energy.gov/industry/bestpractices/iacs.html

Energy Assessments

Description: The U.S. DOE conducts plant energy assessments to help manufacturing facilities across the nation identify immediate opportunities to save energy and money, primarily by focusing on energy-intensive systems, including process heating, steam, pumps, fans, and compressed air.

Target Group: Large plants

Format: Online request

Contact: U.S. Department of Energy

URL:
http://www1.eere.energy.gov/manufacturing/tech_deployment/energy_assessment.html

Better Building, Better Plants (BBBP)

Description: The Better Building, Better Plants program is a national partnership initiative to drive a 25% reduction in industrial energy intensity in 10 years while decreasing carbon emissions and enhancing U.S. competitiveness. Leaders of industrial companies are invited to take a corporate-wide voluntary Pledge to reduce the energy intensity of their industrial operations by 25% or more in 10 years. Companies in partnership with the U.S. DOE, will work to improve energy management and identify the most cost-effective options for energy and carbon savings.

Target Group: Building and industry

Contact: U.S. Department of Energy

URL: http://www4.eere.energy.gov/challenge/home

Manufacturing Extension Partnership (MEP)

Description: MEP is a nationwide network of not-for-profit centers in over 400 locations providing small- and medium-sized manufacturers with technical assistance. A center provides expertise and services tailored to the plant, including a focus on clean production and energy-efficient technology.

Target Group: Small- and medium-sized plants

Format: Direct contact with local MEP Office

Contact: National Institute of Standards and Technology, (301) 975-5020

URL: http://www.nist.gov/mep/

Small Business Development Center (SBDC)

Description: The U.S Small Business Administration (SBA) administers the Small Business Development Center Program to provide management assistance to small businesses through 58 local centers. The SBDC Program provides counseling, training and technical assistance in the areas of financial, marketing, production, organization, engineering and technical problems and feasibility studies, if a small business cannot afford consultants.

Target Group: Small businesses

Format: Direct contact with local SBDC

Contact: Small Business Administration, (800) 8-ASK-SBA

URL: http://www.sba.gov/sbdc/

ENERGY STAR – Selection and Procurement of Energy-Efficient Products for Business

Description: ENERGY STAR identifies and labels energy-efficient office equipment. Look for products that have earned the ENERGY STAR. They meet strict energy efficiency guidelines set by the EPA. Office equipment included such items as computers, copiers, faxes, monitors, multifunction devices, printers, scanners, transformers and water coolers.

Target Group: Any user of labeled equipment.

Format: Website

Contact: U.S. Environmental Protection Agency

URL: http://www.energystar.gov/index.cfm?c=bulk_purchasing.bus_purchasing

Training

ENERGY STAR

Description: As part of ENERGY STAR's work to promote superior energy management systems, energy managers for the companies that participate in ENERGY STAR are offered the opportunity to network with other energy managers in the partnership. The networking meetings are held monthly and focus on a specific strategic energy management topic to train and strengthen energy managers in the development and implementation of corporate energy management programs.

Target Group: Corporate and plant energy managers

Format: Web-based teleconference

Contact: Climate Protection Partnerships Division, U.S. Environmental Protection Agency

URL: http://www.energystar.gov/

Workforce Development and Training

Description: The U.S. DOE provides training and training materials to support the efforts of the program in efficiency improvement of utilities (compressed air, steam) and motor systems (including pumps). Training is provided regularly in different regions. One-day or multi-day trainings are provided for specific elements of the above systems. The U.S. DOE also provides training on other industrial energy equipment, often in coordination with conferences.

Target Group: Technical support staff, energy and plant managers

Format: Various training workshops (one day and multi-day workshops)

Contact: U.S. Department of Energy

URL: http://www1.eere.energy.gov/industry/bestpractices/training.html

Compressed Air Challenge®

Description: The not-for-profit Compressed Air Challenge® develops and provides training on compressed air system energy efficiency via a network of sponsoring organizations in the United States and Canada. Three levels of training are available: (1) Fundamentals (1 day); (2) Advanced (2 days); and (3) Qualified Specialist (3-1/2 days plus an exam). Training is oriented to support implementation of an action plan at an industrial facility.

Target Group: Compressed air system managers, plant engineers

Format: Training workshops

Contact: Compressed Air Challenge: Info@compressedairchallenge.org

URL: http://www.compressedairchallenge.org/

Financial Assistance

Below major federal programs are summarized that provide assistance for energy efficiency investments. Many states also offer funds or tax benefits to assist with energy efficiency projects (see below for State Programs). However, these programs can change over time, so it is recommended to review current policies when making any financial investment decisions.

Energy Efficiency and Renewable Energy (EERE) Financial Opportunities

Description: The Office of EERE works with business, industry, universities, and others to increase the use of renewable energy and energy efficiency technologies. One way EERE encourages the growth of these technologies is by offering financial assistance opportunities for their development and demonstration.

Target Group: Business, industry, universities, consumers, federal energy managers, inventors, and states.

Format: Solicitations

Contact: U.S. Department of Energy

URL: http://www1.eere.energy.gov/financing/business.html

Small Business Administration (SBA)

Description: The Small Business Administration provides several loan and loan guarantee programs for investments (including energy-efficient process technology) for small businesses.

Target Group: Small businesses

Format: Direct contact with SBA

Contact: Small Business Administration

URL: http://www.sba.gov/

State and Local Programs

Many state and local governments have general industry and business development programs that can be used to assist businesses in assessing or financing energy-efficient process technology or buildings. Please contact your state and local government to determine what tax benefits, funding grants, or other assistance they may be able to provide your organization. This list should not be considered comprehensive but instead merely a short list of places to start in the search for project funding. These programs can change over time, so it is recommended to review current policies when making any financial investment decisions.

Database of State Incentives for Renewables & Efficiency (DSIRE)

Description: DSIRE is a comprehensive source of information on state, local, utility, and federal incentives and policies that promote renewable energy and energy efficiency. Established in 1995, DSIRE is an ongoing project of the NC Solar Center and the Interstate Renewable Energy Council funded by the U.S. Department of Energy.

Target Group: Any industry

URL: http://www.dsireusa.org/

Summary of Motor and Drive Efficiency Programs by State

Description: A report that provides an overview of state-level programs that support the use of NEMA Premium® motors, ASDs, motor management services, system optimization and other energy management strategies.

Target Group: Any industry

Contact: Consortium for Energy Efficiency (CEE), (617) 589-3949

URL: http://www.cee1.org/ind/programsummary/index.php

California – Public Interest Energy Research (PIER)

Description: PIER provides funding for energy efficiency, environmental and renewable energy projects in the state of California. Although there is a focus on electricity, fossil fuel projects are also eligible.

Target Group: Targeted industries (e.g. food industries) located in California

Format: Solicitation

Contact: California Energy Commission, (916) 654-4637

URL: http://www.energy.ca.gov/contracts/index.html

California – Energy Innovations Small Grant Program (EISG)

Description: EISG provides small grants for development of innovative energy technologies in California. Grants are limited to $95,000.

Target Group: All businesses in California

Format: Solicitation

Contact: California Energy Commission, (619) 594-1049

URL: http://www.energy.ca.gov/research/innovations/index.html

California – Savings By Design

Description: Design assistance is available to building owners and to their design teams for energy-efficient building design. Financial incentives are available to owners when the efficiency of the new building exceeds minimum thresholds, generally 10% better than California's Title 24 standards. The maximum owner incentive is $150,000 per free-standing building or individual meter. Design team incentives are offered when a building design saves at least 15%. The maximum design team incentive per project is $50,000.

Target Group: Nonresidential new construction or major renovation projects

Format: Open year round

URL: http://www.savingsbydesign.com/

Iowa – Alternate Energy Revolving Loan Program

Description: The Alternate Energy Revolving Loan Program (AERLP) was created to promote the development of renewable energy production facilities in the state.

Target Group: Any potential user of renewable energy

Format: The Energy Center provides loan funds equal to 50% of the total financed cost of a project (up to $1 million) at 0% interest. Proposals under $50,000 are accepted year-round. Larger proposals are accepted on a quarterly basis.

Contact: Iowa Energy Center, (515) 294-3832

URL: http://www.iowaenergycenter.org/alternate-energy-revolving-loan-program-aerlp/

New York – Industry Research and Development Programs

Description: The New York State Energy Research & Development Agency (NYSERDA) operates various financial assistance programs for New York businesses. Different programs focus on specific topics, including process technology, combined heat and power, peak load reduction and control systems.

Target Group: Industries located in New York

Format: Solicitation

Contact: NYSERDA, (866) NYSERDA

URL: http://www.nyserda.ny.gov/en/Funding-Opportunities.aspx

Oregon – Energy Trust Production Efficiency Program

Description: Incentives for energy efficiency projects are offered for Oregon businesses that are serviced by either Pacific Power or Portland General Electric. Current incentive levels are $0.25/kWh saved up to 60% of the project cost. Lighting incentives are treated differently. There are standard incentive levels for specific fixture replacements (exp. $30/fixture). If a fixture replacement does not qualify for a standard incentive, but it does save energy, a custom incentive can be calculated using $0.17/kWh saved up to 35% of the project cost. Premium efficiency motor rebates are also offered at $10/hp from 1 to 200 hp motors. Over 200 hp, the current incentive levels of $0.25/kWh saved up to 60% of the project cost are used to calculate an incentive.

Target Group: Commercial and industrial companies in Oregon

Contact: Energy Trust of Oregon,

URL: http://energytrust.org/industrial-and-ag/

Wisconsin – Focus on Energy

Description:	Energy advisors offer free services to identify and evaluate energy-saving opportunities, recommend energy efficiency actions, develop an energy management plan for business; and integrate elements from national and state programs. It can also provide training.
Target Group:	Industries in Wisconsin
Format:	Open year round
Contact:	Wisconsin Department of Administration, (800) 762-7077
URL:	http://www.focusonenergy.com/