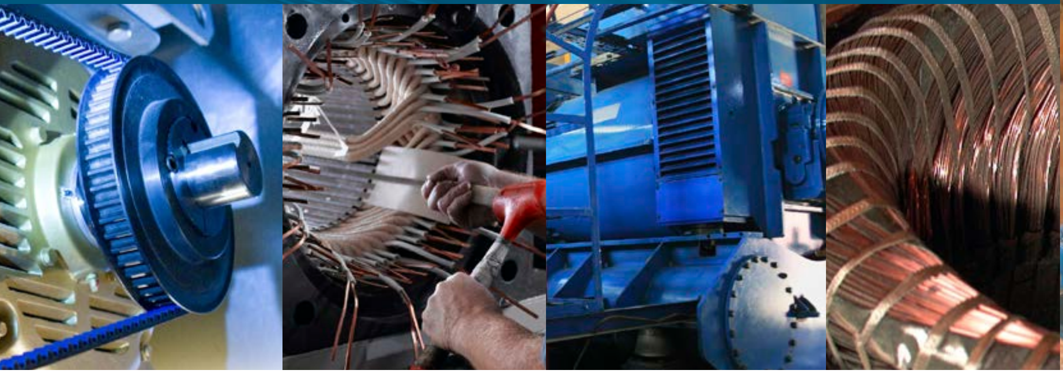
U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

ADVANCED MANUFACTURING OFFICE

Continuous Energy Improvement in Motor Driven Systems



A GUIDEBOOK FOR INDUSTRY

DISCLAIMER

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This document supersedes and updates DOE's 1997 publication *Energy Management for Motor Driven Systems.*

This update includes the following overarching principles within the update:

- All facilities with motor-driven assets are encouraged to use a systems-based approach within any motor management activity regardless of whether that entails new design, assessment of existing systems, or modifications to those systems. Thereby all motor-driven systems and the related motors, drives, and related components are selected and operated in such a way as to match motor-driven system energy needs with the energy delivered by the motor, drive, and related components for optimum life-cycle costs.

- All businesses, as well as public and private entities that either own, manage, or facilitate motor-driven asset efficiency should consider both life-cycle energy costs and the energy management approach contained within the International Organization for Standardization (ISO) 50001-2011 Energy Management Standard and the related American Society of Mechanical Engineers (ASME) assessment standards for pump, fan (under development), and compressor systems.

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INTRODUCTION

Energy Management Overview

An energy management system is a systematic approach to continuously improve energy efficiency through:

- Gathering and tracking energy use data
- Establishing a benchmark energy performance indicator (EnPI) for your facility
- Understanding how and where energy is used in your plant
- Conducting energy audits and technical assessments to identify energy savings opportunities
- Establishing energy savings targets, objectives, and goals
- Prioritizing energy savings opportunities to create an action plan
- Implementing recommended energy savings measures
- Verifying that expected energy savings occur
- Monitoring and evaluating progress and reporting results to upper management.

Interest in establishing energy management systems at the corporate and individual plant levels has intensified with the adoption of the International Organization for Standardization (ISO) 50001–2011 Energy Management Standard, the American National Standards Institute Energy Management Standard (ANSI/MSE) 50021–2012, and with the U.S. Department of Energy (DOE) facilitated Superior Energy Performance Program (SEP).[I-1, I-2]

A number of paper and electronic publications and guidance document are available to assist industries with organizing and establishing their energy management systems.[I-3, I-4, I-5, I-6] Some provide a "how-to" guide on creating, strengthening, building, launching, and maintaining an energy management team as well as an outline of the process and procedural issues. One such resource is DOE's eGuide for ISO 50001. For additional information, visit DOE's Advanced Manufacturing Office (AMO) website at *www.manufacturing.energy.gov*.

The U.S. Department of Energy funds the research, development, and demonstration of highly efficient and innovative manufacturing technologies.

The Department is also working to create a network of Manufacturing Innovation Institutes (*www1.eere.energy.gov/manufacturing/amp/index.html*), each of which will create collaborative communities to target a unique technology in advanced manufacturing (*www1.eere.energy.gov/manufacturing/innovation/index.html*)

DOE's eGuide addresses such topics as:

- Securing top management commitment to energy savings
- Appointing an energy manager and energy champions
- Establishing an energy team
- Collecting energy use data
- Defining a normalized facility energy use baseline or benchmark
- Establishing an energy tracking system
- Conducting assessments to identify and prioritize energy savings opportunities
- Developing plans to address staff training needs
- Defining purchasing specifications
- Reviewing and reporting progress to upper management
- Integrating energy management best practices into the corporate culture.

AMO also has established a program to enable partnering manufacturers to obtain technical support and gain national recognition for their energy management efforts. Under the Better Plants *(www.eere.energy.gov/manufacturing/tech_assistance/betterplants/)* program, partners demonstrate their commitment to saving energy by signing a voluntary pledge to reduce their corporate energy intensity (energy use per unit of product) by 25% over 10 years.

SEP is a certification program that provides facilities with guidance toward achieving continual improvement in energy efficiency while maintaining competitiveness. A basic element of SEP is implementation of the ISO 50001 energy management standard with additional requirements to achieve and document energy performance improvement. Certification requires third party verification of conformance to ISO 50001 and energy performance improvement. Learn more about SEP *(www.superiorenergyperformance.net)* and the energy management standard *(www.eere.energy.gov/energymanagement)*.

ASME *(www.asme.org)* has developed a set of standards that support the energy management planning process by providing guidance and protocols for conducting system-level energy efficiency assessments. While use of these standards is not required for ISO or SEP certification, their use helps to ensure that energy efficiency opportunities are properly identified, analyzed, and implemented in a systems-focused and life-cycle cost prioritized fashion. The standards are available through ASME and include:

- ASME EA-1-2009—Energy Assessment for Process Heating Systems
- ASME EA-2-2009—Energy Assessment for Pumping Systems
- ASME EA-3-2009—Energy Assessment for Steam Systems
- ASME EA-4-2010—Energy Assessment for Compressed Air Systems.

DOE also has developed material designed to assist energy managers with achieving results. An energy assessment is only the initial step toward project implementation and the achievement of energy savings. The publication *Guiding Principles for Successfully Implementing Industrial Energy Assessment Recommendations* contains 11 "implementation principles" that help to define assessment expectations and prepare plant staff for ultimate project implementation.[I-9] In addition to the resources available through DOE, useful publications are also available from other organizations on related topics such as the depreciation aspects of the tax code, itemizing the "lost tax revenue" and other "lost revenue streams" that occur when efficiency projects are not installed.[I-10]

Motor management—summarized in **Chapter 1**—is a subset of broader energy management planning activities. It is a logical starting point for initiating an energy management program as it includes such common data gathering elements as understanding your utility billing statement and rate schedule; determining incremental, time-of-day, or seasonal costs for energy in kilowatt hours (kWh), demand (kW), and power factor penalties; conducting a motor survey; taking field measurements (voltage, amperage, kW); estimating annual motor-driven equipment operating hours; and identifying and analyzing motor and drive energy efficiency opportunities. Energy savings verification often involves taking additional measurements or power logging at the motor control center.

After completing motor management planning activities, plant staff should know their annual electrical energy use and operating costs associated with all motor-driven equipment. They should be able to track energy flows in their plant to major energy consuming loads, and summarize energy use by plant process or type of end use equipment (fans, pumps, air compressors, and conveyance systems). This information is of use when scheduling energy assessments or targeting major energy consuming processes for future study.

Continuous Energy Improvement in Motor Driven Systems takes the reader through the steps necessary to develop a motor improvement action plan. An action plan indicates which motors should be replaced immediately with NEMA Premium® efficiency models; which should be replaced with premium efficient motors when they fail and would otherwise require repair; and which motors should be repaired (following best practice repair standards) and returned to service. The action plan also identifies which motors offer potential adjustable speed drive flow control energy savings opportunities, makes recommendations regarding establishing a premium efficiency-ready spares inventory, discusses the benefits of accelerated replacement of old standard efficiency motors, discusses improvements in maintenance practices and activities, and indicates opportunities for power transmission system efficiency upgrades, and identifies applications suitable for adjustable speed drive retrofits.

Continuous Energy Improvement in Motor Driven Systems is the successor to DOE's 1997 publication *Energy Management for Motor Driven Systems*. The updated publication is revised to focus not only on motors, but also includes such topics as power transmission systems (belts and gears), matching driven equipment to process requirements, and the application of adjustable speed drives. While the original publication did include chapters on "tuning" your in-plant distribution systems and the benefits of power factor correction, a component approach that considers just the motor within a wire-to-work system is inadequate. Those conducting energy assessments as part of an energy management program must consider a systems approach and recognize and understand component interactions.

To support the systems approach, this publication indicates how motors of different efficiency classes respond to constant and variable torque loads, illustrates energy efficient power transmission opportunities, and discusses how adjustable speed drives can save energy and reduce costs in fan applications where flow control is currently achieved with inlet guide vanes or discharge dampers and in pumping applications where throttling valves are used. Many other DOE publications, including energy tip sheets, case studies, sourcebooks, and guidebooks are available on completing fan, pumping, chilled water, steam, compressed air, and process heating assessments [I-11, I-12, I-13, I-14, I-15, I-16, I-17, I-18, I-19] Access these publications at AMO's Energy Resource Center *(www.eere.energy.gov/manufacturing/tech_assistance/ecenter.html)*.

Continuous Energy Improvement in Motor Driven Systems also is designed to complement and support DOE's MotorMaster+ motor selection and motor management software tool. MotorMaster+ allows users to create or import an inventory of in-plant operating and spare motors. Motor load, efficiency at that load point, annual energy use, and annual operating costs are determined when field measurements are available. The software helps you to identify inefficient or oversized motors and computes the savings that would be obtained by replacing older, standard efficiency motors with their premium efficiency counterparts. The software tool can complete energy savings analyses for motors with constant or variable loads. Other DOE software tools are available to help users identify savings associated with replacing inefficient pumps, fans, and air compressors.

MotorMaster+ also contains inventory management, maintenance logging, life-cycle costing, energy accounting, energy savings tracking and trending, and environmental reporting capabilities. The tool includes a manufacturers database that lists motor price and performance data for thousands of motors sold in North America. Obtain MotorMaster+ at no cost from AMO's Energy Resource Center. The software runs on local or wide-area networks for access by multiple users.

This document and the MotorMaster+ software were developed through AMO as tools to assist manufacturing and process industries with saving energy and remaining competitive. They are most frequently used by plant engineers, facility energy managers, procurement personnel, electricians, and maintenance staff. These tools also are used by energy managers at military bases, federal buildings, water supply and wastewater treatment plants, irrigation districts, utility power plants, hospitals, universities, and commercial buildings.

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GLOSSARY

cost	new motor cost
$cost_{INST}$	installation cost
Δcost	extra cost for premium efficiency motor
ΔDL	percent reduction in distribution losses
ΔE	annual electric energy saved, in kWh
ΔP	savings from efficiency improvement, in kW
ΔV	rms voltage across a junction
E	electric energy, in kilowatt-hours, kWh
η	efficiency as operated, in %
η_2	corrected efficiency
η_1	efficiency before correction
η_{STD}	efficiency of a standard motor as operated, in %
η_{EE}	efficiency of an energy efficient motor as operated, in %
η_{PREM}	efficiency of a NEMA premium motor as operated, in %
η_R	efficiency at rated load
hours	annual operating hours
hp	actual output horsepower
hp_1	output horsepower before correction
hp_2	corrected output horsepower
hp_R	nameplate rated horsepower
I	rms current
I_R	nameplate rated current, Amps
load	output power as a % of rated power
LF	load factor, in %
P	power or demand, in kilowatts, kW
p	power dissipated in a junction, in Watts, W
P_2	corrected input power
P_{APP}	apparent power, in kilovolt amperes, kVA
P_{APP1}	apparent power or demand before correction, in kVA
P_{APP2}	apparent power or demand after correction, in kVA
P_{BILLED}	adjusted or billable power, in kW
PF	power factor as a decimal
PF_1	power factor before correction
PF_2	power factor after correction
P_R	input power at full rated load, in kW
P_{REACT}	reactive power, in kilovars, kVAR
R	resistance, in ohms
$Rate_D$	monthly demand charge, in $/kW-mo
$rate_E$	tailblock energy charge, in $/kWh
rebate	utility rebate for premium efficiency motor
S	measured speed, in RPM
S_R	nameplate full load speed
S_S	synchronous speed, in RPM
savings	total savings, in dollars ($)
slip	synchronous speed – measured speed, in RPM
SPB	simple payback, in years
unbal	voltage unbalance, in %
V	root-mean-square (rms) voltage, mean line-to-line of 3 phases
$V\eta_{MAX}$	line to line phase voltage deviating most from mean of 3 phases
V_R	nameplate rated voltage

LIST OF ACRONYMS

AC	alternating current
AEMT	Association of Electrical and Mechanical Trades
AMCA	Air Movement and Control Association
AMO	Advanced Manufacturing Office
ANSI	American National Standards Institute
ASD	Adjustable speed drive
BEP	best efficiency point
BHP	brake horsepower
CDA	Copper Development Association
CMMS	computerized maintenance management system
CSA	Canadian Standards Association
cfm	cubic feet per minute
CT	current transducer
DC	direct current
DOE	U.S. Department of Energy
EASA	Electrical Apparatus Service Association
EERE	Office of Energy Efficiency and Renewable Energy
EnPI	energy performance indicator
EISA	Energy Independence and Security Act of 2007
EPAct	Energy Policy Act of 1992
ePEP	Plant Energy Profiler
FSAT	Fan System Assessment Tool
gpm	gallons per minute
GR	gear ratio
Hz	hertz
hp	horsepower
I2R	resistance?
I	amperage or current
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IGBT	insulated gate bipolar transistor
IP	ingress protection
ISO	International Organization for Standardization
kW	kilowatt
kWh	kilowatt-hour
kVA	kilovolt-ampere
kVAR	kilovolt-ampere reactive
kVARh	kilovolt-amp-hour reactive
LED	light-emitting diode
LF	load factor
mm	millimeters
MW	megawatt
MMBtu	million Btu
MVA	megavolt ampere
MVAR	megavolt ampere reactive
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association
NFPA	National Fire Protection Association
ODP	open drip proof
OEM	original equipment manufacturer
ORMEL	Oak Ridge Motor Efficiency and Load
PC	personal computer
PEM-Ready	premium efficiency motor-ready
PF	power factor
PG&E	Pacific Gas & Electric
PLC	programmable logic controller
PSAT	Pumping System Assessment Tool
PWM	pulse-width modulated
RMS	root-mean-square
rpm	revolutions per minute
TEAO	totally enclosed air over
TEBC	totally enclosed blower-cooled
TEFC	totally enclosed fan-cooled
TENV	Totally enclosed fan ventilated
TOU	time of use
V	volt
V/Hz	volts to hertz
W	watt
WP	weather protected
WSU	Washington State University

CHAPTER 1

STARTING YOUR MOTOR MANAGEMENT PROGRAM

Benefits of Motor Management

Electric motors tend to be taken for granted and are among the least well-managed industrial equipment, even though motor-driven equipment accounts for approximately 70% of the electrical energy consumed by process industries.[1-1,1-2] This percentage increases to approximately 90% for electrical intensive industries such as mining, oil and gas extraction, and for water supply, wastewater treatment plants, and irrigated agriculture.[1-3]

Motors that are not properly managed can and do result in billions of dollars in wasted energy and operating costs to industry.[1-1] Electric motor-driven systems used in U.S. industrial process industries consumed 679 billion kilowatt-hours (kWh) of electrical energy in 1994.[1-3] Motors used in industrial space heating, cooling, and ventilation systems use an additional 68 billion kWh. A detailed analysis of the U.S. motor systems inventory indicates that this energy use could be reduced by 11% to 18% if plant managers implement all cost-effective applications of mature and proven energy efficiency technologies and practices.[1-3]

This chapter describes why and how motor management planning should take place. A large industrial plant may have hundreds or even thousands of motors. These motors operate all kinds of process equipment and their failure can result in losses in plant productivity and reductions in product quality.[1-4] All too often, little is known about how these motors are loaded and how much they cost to operate. Electrical costs often are treated as a fixed expense rather than one that can be managed. An old adage states that “you can’t manage what you can’t measure.” Motors typically receive attention only when they fail and shut down a critical operation. Then a hurried decision is made to either repair or replace the failed motor.[1-5] Decisions to repair or replace motors consequently are based on motor availability and simple payback analysis, rather than evaluation and planning.[1-6]

Plant staff must know the appropriate action—repair versus replace—for each motor before it fails. Motor management involves minimizing operating costs while maintaining efficient and reliable production. In most cases, replacing a standard efficiency motor with a premium efficiency motor does pay off—it is just a question of how fast.[1-7, 1-8] The more you know about your in-plant motor population, the more you can save. In addition to providing the basis for reducing energy use and increasing profits, information gathered on motors and driven-equipment can be used to establish effective predictive and preventive maintenance programs, allocate costs between departments, and optimize inventories of spare motors and parts.[1-4]

Motor Energy Management Best Practices

Begin to reduce losses and increase profits by starting a motor management program.[1-1] A motor management program involves proactive rather than reactive actions. It requires gathering data, using this data to target efficiency opportunities, and then conducting analyses to determine expected energy and cost savings resulting from installing efficiency measures. Information requirements include electrical utility rates, existence of utility efficiency incentives, and gathering motor nameplate data, application information, field measurements (to determine the load imposed upon the motor by its driven equipment), repair history, and annual operating hours.

Include these elements in your motor management program:[1-4]

- Adopt a new motor purchase policy and a motor repair/replace policy based on a commitment to select, purchase, and operate premium efficiency equipment.
- Educate the finance and purchasing departments on the value of energy efficiency improvements. Empower them to make decisions based upon “total cost of ownership” or life cycle costing methodologies.
- Consider “Model Repair Specifications” (such as ANSI/Electrical Apparatus Service Association [EASA] AR100-2010).
- Identify motors that are mismatched to their load requirements.
- Conduct failure analyses to determine the root cause of the failure, correct system issues, and replace “problem” motors (e.g., motors that frequently fail and must be sent out for repair) with motor designs better suited for the application.
- Identify which operable standard efficiency motors should be immediately replaced and which motors should be replaced with premium efficiency motors at their time of failure.
- “Tune” the in-plant electrical distribution system to reduce voltage unbalance to acceptable limits and eliminate voltage drops due to “hot spots.”
- Reduce power factor penalty charges through installation of power factor correction capacitors when economically justified.
- Establish effective maintenance programs that will “lock in” the projected savings.

Getting Started: Assembling Your Motor Management Team

A motor management program is a team effort to create energy awareness, to collect and organize information for both motors and driven-equipment, and then to identify, analyze, and implement energy efficiency opportunities. Assembling a team solidifies support for developing and implementing motor management strategies.[1-5] At a minimum, this team should include the plant energy manager or energy coordinator, plant engineer, plant electrician, and the maintenance manager. Including a representative from finance often is a good decision as he or she can translate energy savings into dollar savings and determine the rate-of-return on investment in efficiency measures.

The team may wish to use in-house staff to complete motor surveys and conduct repair-versus-replace analyses or alternatively, retain an industrial service provider. By conducting an in-house audit and survey process, plant employees will regard energy as a manageable expense, gain the ability to critically analyze the way their facility uses energy, and become more aware of how their day-to-day activities affect plant energy consumption.[1-9] The team must obtain motor prices or list price discount factors from their motor distributor, repair costs from their motor service center representative, and information on motor rebates or other efficiency incentive programs from their utility account executive. After motor survey information has been collected and while new motor purchase and motor repair/replace policies are being developed, the team should expand to include the plant manager, a representative from upper management, and the purchasing staff responsible for motor and drive procurement. Create or purchase an electronic maintenance management system where motor inventory and operating history records can be maintained.[1-10] Such software is often available from motor manufacturers.

Analyzing Your Utility Bills

Chapter 2 explains how to interpret your utility bill and understand charges. Most industrial rate schedules include both an energy charge and a demand charge. The energy charge is equal to the energy rate (in $/kWh) times the total energy use over the billing period (usually a month). The demand charge (in $/kW-mo) is applied to the maximum or peak rate of energy use within the billing period. The peak demand is based upon the highest rolling average energy use over a defined time interval (typically 15 or 30 minutes). Many utilities offer rate schedules with energy and demand charges that vary by season. Some utilities vary their energy rates by the time-of-day, while others charge different rates for different quantities or blocks of energy use. Examine your utility bills and always use the marginal energy cost when evaluating the cost-effectiveness of energy efficiency investments.

Conducting a Motor Survey

Chapters 3 and 4 contain information on motor survey techniques and motor selection and specification considerations. A comprehensive motor survey includes collecting motor nameplate information, location, maintenance records, and application type.[1-11] It also involves estimating annual operating hours and taking field measurements such as input power, volts, and amperage per phase, operating speed, and power factor.[1-5]

Assign an individual who will be responsible for the motor survey. This individual must be familiar with the facility layout and be able to identify general, special, and definite purpose motors. The individual must be aware that some motors that are used in special applications (such as direct current [DC] or NEMA Design C crusher-duty motors and Design D high slip motors) may have unique operational requirements such as high starting torque.[1-12] Motors also may feature a variety of enclosure types or be designed for special or definite purpose applications—such as close-coupled pump, C-face, vertical shaft, severe-duty, washdown duty, totally enclosed air over (TEAO), right angle drive gear, or hazardous location motors. The person doing the survey must be able to safely work around electrical equipment and rotating machinery and attach metering equipment to motor leads when the equipment is shut down.[1-5] Only the plant electrician should attach measurement devices to energized equipment.

Begin the motor survey by obtaining any motor information that has previously been collected. Questions to ask include: Does the facility use a computerized maintenance management system (CMMS)? If so, has motor nameplate data been entered? Or is motor purchase and repair information kept in card files in the maintenance department? Newer industrial plants may find that motor lists were supplied for their process equipment, or that equipment lists are attached to layout or design drawings. Typically, only partial or incomplete information is available, but the equipment lists may indicate the number of motors in a plant, and may provide their locations and horsepower ratings.

Plant personnel often estimate that they have a certain number of motors at a particular location. However, the experience of auditors shows that, when the motors are counted, the actual number can be up to three times the original presumption.[1-5]

When motor data is available electronically, it can be imported into the U.S. Department of Energy's (DOE) MotorMaster+ motor energy management software tool (or one of many others available from utilities or motor manufacturers). For those who need to conduct motor surveys and enter data into a motor inventory management system, a Motor Nameplate and Field Test Data Form is included in Appendix A.

Motor Survey Filter Criteria

While it might be desirable to inventory all motors in a facility, it is not always possible or necessary.[1-5] Focus first on constantly loaded, general purpose, single-speed, three-phase, NEMA or International Electrotechnical Commission (IEC) metric frame alternating current (AC) induction motors rated from 20 through 500 horsepower (hp). Motors of lesser priority from an energy savings standpoint include single-phase, DC, synchronous, hermetically-sealed, centrifuge, crane/hoist, or punch press motors, motors already coupled to an adjustable speed drive, or motors that operate with intermittent, cyclic, or fluctuating loading.

Initially focus on non-specialty motors with easy access and readable nameplates. Place less priority on motors with cost premiums such as high torque/high slip NEMA Design D motors and motors with synchronous speeds of 720 revolutions per minute (RPM) or less, which are often not covered by NEMA's minimum motor full-load efficiency standards.[1-13] For these motor classes, there often is no reliable way of knowing the original or replacement motor efficiency. Medium voltage motor efficiency test procedures are defined in NEMA MG 1-2011 and these motors should be included in the overall motor efficiency improvement plan. For additional information, see "Improve the Efficiency of your Medium Voltage Motors" in **Chapter 7**.

Confine your initial motor survey to the "vital few"—the 20% of operating motors that account for 80% of electrical energy consumption. First consider the largest motors, running the longest hours, and with the highest constant load.[1-13] Given an electricity cost of $0.08/kWh, it costs about $150 per day to operate a continuously operating fully-loaded 100 hp motor.[1-5] Many facility managers consider 60- to 500-hp motors as large, and 1- through 50-hp motors as small. When 1- through 50-hp motors fail, it may cost more to repair the motors than to purchase a new premium efficient replacement. Consider determining a "horsepower breakpoint" for your facility (for more information on this decision-making approach, see **Chapter 7**, "Motor Efficiency Improvement Planning"). Because the motor replacement decision for small general purpose motors is obvious (to replace, depending on availability, rather than repair) you should focus your information gathering and analysis on the large motor population.

Start with problematic systems. Include systems where motors or components are scheduled for maintenance or replacement.[1-4] All large motors operating more than one shift per day or 2,000 hours per year should be inventoried.[1-4, 1-10] Spares should also be included in the survey of large motors. Each motor should be tagged with a permanent identification or equipment number and cataloged. Add new motors to the inventory database when they are purchased and note the storage location of spares.[1-10] Begin to track motor maintenance actions and identify motors that have required repair in the past.

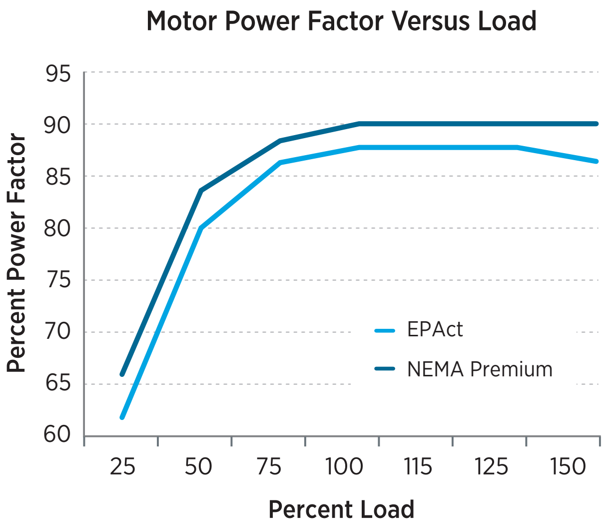
As time permits, expand your information gathering and analysis efforts to include smaller motors. Look for identical or similar units used in the same application.[1-13] Consider systems that have blowers, fans, pumps, or compressors, especially when the flow is controlled by dampers or throttling valves.[1-4] Concentrating attention only on large motors provides an accurate picture of energy flows, but not of energy waste. For example, a 100-hp motor might have a full-load efficiency of 94%—meaning approximately 6% of the energy supplied to the motor—or 4.75 kilowatts (kW)—is converted into electrical resistance heating losses in the copper winding in the stator and in rotor bars, magnetic losses in the stator and rotor, friction in the bearings, and energy absorbed by the cooling fan.[1-14] Now consider twenty 5-hp motors, each with a full-load efficiency of 88%. The total wasted energy is equal to 12% of the input energy or 10.1 kW—more than twice the amount lost by the large motor.[1-15] The availability of a complete motor inventory helps plant staff track motor warranties, maintain data for tax depreciation, and ensure that an appropriate and sufficient stock of spares is maintained.

Motor Load and Operating Hour Estimates

Just because a motor has a nameplate horsepower rating of 50 hp does not mean that it is loaded to constantly deliver 50 shaft hp. Industrial energy auditors have found that, on average, motors are sized so they deliver about 70%-75% of their rated load.[1-5] Actual motor loading in horsepower can be determined by using multi-meters or a true root mean square (RMS) Wattmeter to record the supply voltage, amperage, or power supplied to the motor. Motor load and efficiency estimation techniques are discussed in **Chapter 5**. Motor loading and efficiency can be determined after entering both motor nameplate and field measurement information into the MotorMaster+ in-plant inventory module.

Motors loaded to less than 50% of their rated output are candidates for replacement with a downsized (lower HP) motor. Be cautious when considering downsizing, however; existing motors may have been oversized for legitimate reasons, such as high starting torque requirements or occasional short duration peak loads.[1-10] Because modern energy efficient and premium efficient motors are efficient over a wide range of loads, motor oversizing does not greatly compromise or sacrifice efficient operation.

Most general purpose three-phase induction motors operate at peak efficiency when they are loaded to about 80% of their full-rated load. The charts on this page show the effect on efficiency and power factor due to both light motor loading and overloading. The performance of lightly loaded motors will be discussed in more detail in **Chapter 8**.



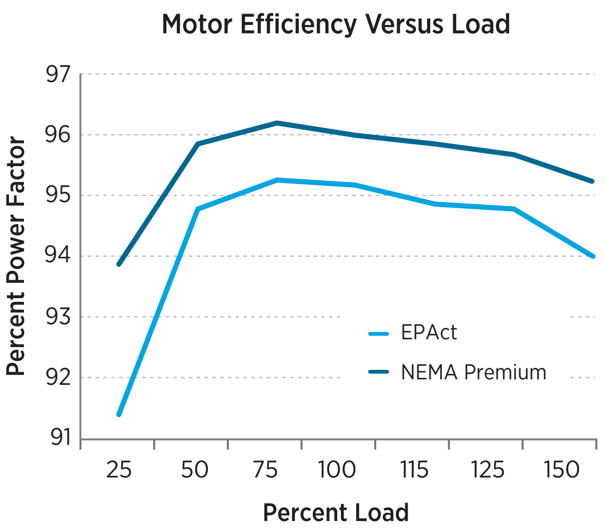


Figure 1-1. Motor Efficiency and Power Factor Versus Load.
Illustration from Baldor Electric

Consult with equipment operators to gain their input and support. Ask mechanics, maintenance staff, process equipment operators, and facility engineers how each piece of motor-driven equipment is operated.[1-13] Identify whether sporadic or continuous operating problems occur.[1-4] Questions to ask include:

- Does the motor operate for one, two, or three shifts?
- Is a backup pump available and is the pump operation rotated to produce even wear?

If automatic controls cycle a motor on and off, on-time versus off-time will have to be estimated. A study conducted by an electrical utility compared predictions of motor annual operating hours to results obtained with data loggers. The study found a wide variation between estimates provided by the end user and the field-measured annual operating hours. The study concluded that end users have a difficult time providing accurate estimates of annual motor run times.[1-16] For constantly loaded motors, remember that projected energy savings are directly proportional to the motor's annual operating hours.

Identifying Motor Energy Efficiency Opportunities

Chapter 6 contains an overview of motor energy, demand, and dollar savings analysis techniques. Motor management involves the immediate or gradual replacement of standard efficiency and energy efficient motors in your plant with higher efficiency models. Before discussing the benefits of replacing operating motors with premium efficiency models, it is useful to summarize some efficiency definitions.

- Standard efficiency motors include many (but not all) motors manufactured before the Energy Policy Act of 1992 (EPAct) took effect in 1997. EPAct required that certain types of motors sold in the United States after October 1997 must meet or exceed minimum full-load efficiency standards for energy efficient motors. EPAct covers general purpose NEMA Design A and B motors, with open or totally enclosed enclosures, rated at 230 or 460 volts (V), sized from 1 to 200 hp, and with synchronous speeds of 3,600, 1,800, and 1,200 RPM. EPAct does not address special purpose motors or require the replacement of older standard efficiency motors. Industrial end users can repair old standard efficiency motors and return them to service if they wish.[1-17] Additional information is included in **Chapter 4**.

- Energy efficient motors are those with nominal full-load efficiency values that equal or exceed the values contained in Table 12-11 of NEMA MG 1-2011. This table is identical to the EPAct requirements but is expanded to include motor ratings up to 500 hp and motors with a synchronous speed of 900 RPM.
- Premium efficiency motors exceed the performance of the energy efficient motors by 1 or 2 percentage points. The minimum nominal full-load efficiency standards for low voltage premium efficiency motors are given in Table 12-12 of NEMA MG 1. The premium efficiency motor standard has expanded to cover medium voltage (5,000 V or less) form-wound motors rated between 250 and 500 hp, as given in Table 12-13 of NEMA MG 1-2011.

Standard efficiency motors up to approximately 200 hp are often considered "economically obsolete." You can identify candidates for replacement by entering utility rate, rebate, and motor nameplate and operating information into the MotorMaster+ in-plant inventory module. Then use the software to quantify energy and dollar savings and indicate which standard efficiency motors should be phased out.

Following are some motor energy efficiency strategies:

- Specify premium efficiency motors when purchasing new motors or rotating equipment.
- Immediately replace standard efficiency "problem" motors with premium efficiency motor models. Conduct a root cause failure analysis for these motors, correct system issues, and consider enclosure upgrades. Chronic motor failures can be due to misuse, misapplication, unsuitability for the operating environment, misalignment/vibration, or poor maintenance practices.
- Immediately replace standard efficiency motors with premium efficiency models when cost-effectiveness criteria are met or replace standard efficiency motors with premium efficiency motor models when standard efficiency motors fail and when cost-effectiveness criteria are met.
- Replace oversized standard efficiency motors with premium efficiency motors that are matched to the load requirements, i.e., operating at about 80% of the rated motor horsepower. This results in the motors operating near their peak efficiency points and provides for longer thermal life. Consider locked rotor or starting torque and load cycling requirements when selecting the replacement motor. Include the cost of a frame adapter or conversion base when considering motor downsizing.
- Correct adverse operating conditions such as voltage variations, voltage unbalance, and high ambient temperatures.[1-7]
- Proactively manage your inventory of spare motors.[1-6, 1-8]

When rewinding standard efficiency motors that will be repaired and returned to service, additional energy and reliability savings are obtained by using "model" repair standards based on best practices.[1-18, 1-19] Consider adjustable speed drives for those in-plant motors connected to variable or constant torque loads (centrifugal fans, pumps, and compressors) that must meet variable process flow requirements. DC motors supplied by a motor-generator (MG) set should be upgraded with solid state controls or replaced by an AC motor with adjustable speed drive flow control.

Creating Your Motor Management Action Plan

Chapter 7 provides additional details on motor management planning. One of the major goals of a plant manager is to reduce the "total cost of ownership" of plant assets.[1-20] Many plant managers, however, do not realize that electrical energy costs can account for over 97% of a motor's lifetime costs.[1-8] Significant savings can be achieved through increasing motor and driven-equipment efficiency, resulting in a reduction in the amount of energy required per unit of production. The motor management team should examine energy usage and operating costs for each plant process and piece of motor-driven equipment. They should then determine how purchasing and installing premium efficient motors can reduce these costs.

Some industries have attempted to decrease ownership costs through standardization, e.g., replacing old U-frame motors with T-frame motors or through purchasing only motors with totally enclosed fan-cooled enclosures or establishing a corporate policy to purchase all motors from a single manufacturer. Motor manufacturers or distributors often reward volume purchasers with a larger discount on motor list prices. Another important goal is to improve uptime by installing reliable motors. Many industries are attempting to reduce downtime by specifying the purchase of severe-duty or Institute of Electrical and Electronics Engineers (IEEE) 841 petroleum and chemical duty motors.[1-20] The food and beverage and pharmaceutical industries require frequent equipment sanitation, and special washdown duty motors have been developed for that application.

Motor repair/replace decision rules are sometimes presented in the form of a "horsepower breakpoint" chart. For a selected number of annual operating hours and for the electrical energy rate in effect at your plant, the breakpoint chart indicates the motor horsepower rating above which you repair failed motors and below which you recycle rather than repair the motors.[1-10] Recycled motors are to be replaced with premium efficiency motor models. For additional information on horsepower breakpoint charts, see **Chapter 4** "Premium Efficiency Motor Application Considerations" of DOE's *Premium Efficiency Motor Selection and Application Guide.*

For the use of breakpoint charts to be an effective repair/replace decision-making tool, separate charts must be constructed for each motor speed (3,600 RPM, 1,800 RPM, 1,200 RPM) and enclosure type present in your plant. Some breakpoint chart users recommend that the charts be prepared first and used as a motor survey filter. The motor surveys then start at or very near the horsepower breakpoint. Breakpoint charts can allow an energy management team to develop useful policy directions without gathering a huge quantity of information.

Ultimately, it is recommended that a comprehensive motor survey be completed and then the cost effective repair/replace action for each motor in your plant be determined using the MotorMaster+ software tool. Tag motors so the maintenance staff takes the correct action when an operating motor fails. See Figure 7-6 for Sample In-Service Motor Repair/Replace Tags.

Establish an on-site premium efficiency motor-ready (PEM-Ready) spares inventory to ensure that a premium efficiency motor is installed when it is the recommended replacement for a failed standard efficiency motor. A PEM-Ready spares inventory is established by identifying motor ratings and frame sizes where a number of standard efficiency motors are in operation and no premium efficiency spare is available in the event of a standard efficiency motor failure. Purchasing premium efficiency motors to store in the on-site spares warehouse ensures that a premium efficiency motor is installed when a standard efficiency motor fails and replacement is recommended. The failed standard efficiency motor should be recycled and a new premium efficiency motor purchased to replace the premium efficiency motor that was removed from the spares warehouse and put into service. In this manner, the PEM-Ready spare inventory automatically replenishes itself. A PEM-Ready spares inventory is necessary when replacement premium efficiency motors are not immediately available from a local distributor.

Helpful Tip

Avoid Decision-Making Based on Outdated Information or Energy "Myths."

Some industries have adopted "decision rules" to govern motor repair/replace actions. Often, decision rules are invalid because they are based on dated or incorrect information. One rule of thumb often found in motor management publications is that a premium efficiency motor should be purchased when the repair will cost more than 60% of the cost of the new motor.[1-10] Other industrial motor management planning guides recommend that when the cost of downtime per hour for a critical application exceeds twice the purchase price of a premium efficiency motor, the premium efficiency motor should be installed at the earliest possible opportunity.[1-10] Yet others suggest replacing failed large motors with premium efficiency motors after the motor has been in service for 10 to 15 years.[1-20] Another decision rule is that older standard efficiency motors (with full-load efficiency values below MG 1 Table 12-11) should *not* be rewound. The failed motor should be scrapped and replaced with a premium efficiency motor.[1-4] Others recommend that old standard efficiency motors operating for 2 or 3 shifts per day should be immediately replaced with premium efficiency models, while standard efficiency motors operating for a single shift per day should be replaced upon failure.[1-21]

The adoption of generalized decision "rules of thumb" should be avoided as they can lead to incorrect decisions. Decisions should be based on the motor management action plan, which considers actual operating schedules, utility rates, end-use applications, and motor repair versus new motor purchase costs in effect at your plant.

Implementing your motor management action plan begins with these steps:

- Assemble your motor management team.
- Create motor repair/replace breakpoint charts.
- Conduct a motor survey.
- Create a motor purchase policy.
- Make purchase decisions based on life cycle costing, not on first cost alone.

- Adopt best practices repair standards based upon ANSI/EASA AR100-2010.
- Immediately replace problem motors or motors that are shown by predictive maintenance or condition assessment techniques to be progressively deteriorating and/or in danger of failure.
- Consider the immediate replacement of operating motors with premium efficiency motors when the MotorMaster+ software indicates it is cost-effective.
- Consider downsizing motors loaded at less than 50% of full-load.
- Determine the availability of utility incentives.
- Investigate price discounts available through volume purchases.
- Determine the appropriate action to take upon motor failure. Know which motors should be repaired using best practices. Tag standard efficiency motors that should be replaced with premium efficiency models when they fail.
- Establish a PEM-Ready spares inventory.
- Use environmentally acceptable methods for recycling motors.[1-4]
- After premium efficiency motors have been installed, take the measurements necessary to validate the energy and dollar cost savings. Take the measurements necessary to validate the energy and dollar cost savings after premium efficiency motors have been installed.
- Make your program visible. Share successes to build support so that your motor efficiency improvement efforts can be extended to include process modifications and efficiency measures for driven-equipment.

System Efficiency Improvement Opportunities

Chapter 8 addresses energy savings from motor systems. The system definition usually includes a distribution transformer, motor starter, soft starter, or adjustable speed drive, electric motor, mechanical power transmission components (belts/pulleys or gear reducers), and the driven equipment. Energy savings may come from matching motor driven-equipment to load requirements, from mechanical power transmission system (belt and gear) upgrades, and from adjustable speed drive retrofits. The primary energy efficiency opportunities in fluid handling equipment exist beyond the shaft of the motor. Extend your efforts to optimize the performance of pumping systems, compressed air systems, fan systems, chilled water systems, and fuel-fired equipment such as furnaces, boilers, and ovens. Many systems use constant speed motors with process flows mechanically regulated by throttling valves, discharge dampers, inlet guide vanes, or fluid couplings. These devices are inherently inefficient, as energy dissipates across the throttling device.[1-4] Many techniques are available to match fan, pump, and blower operations to actual system requirements, including speed modulation, equipment modifications, equipment resizing, booster or pony pump applications, and changing inlet or outlet conditions.[1-22]

Power Factor Correction

Chapter 9 includes the definition of power factor, discusses utility imposed low power factor penalties, and provides examples of how to determine the benefits associated with the installation of power factor correction capacitors. The chapter also discusses capacitor sizing for individual motors or entire plant loads and provides tips on locating capacitors. Also included is a section on the secondary benefits due to power factor correction and a discussion of how to avoid harmonic resonances when installing capacitors.

Use the success of your motor management program to launch your inclusive corporate energy management program. DOE has produced a wealth of tools and information to assist industrial plant staff in their energy management efforts. This information includes eGuide and eGuide lite, energy tip sheets, best practices sourcebooks, technical case studies, and performance spotlights.

In addition to MotorMaster+, DOE makes available the following software tools at no cost. These tools are designed to assist the facility or corporate energy manager with tracking energy use and identifying and analyzing savings from efficiency opportunities. These tools include:

- Plant Energy Profiler (ePEP)
- MotorMaster International
- Pumping System Assessment Tool (PSAT)
- AirMaster+: A Compressed Air System Assessment Tool
- Fan System Assessment Tool (FSAT)
- Steam System Assessment Tool (SSAT)
- 3EPlus Insulation Thickness Optimization Tool

- Process Heating Assessment and Survey Tool (PHAST)
- Chilled Water System Analysis Tool (CWSAT)
- Combined Heat and Power (CHP) Tool
- NOx and Energy Assessment Tool (NEAT)

For additional information or resources on efficiency improvement measures for motors or motor-driven equipment, visit DOE's Advanced Manufacturing Office (AMO) Energy Resource Center *(www.eere.energy.gov/manufacturing/tech_assistance/ecenter.html)*.

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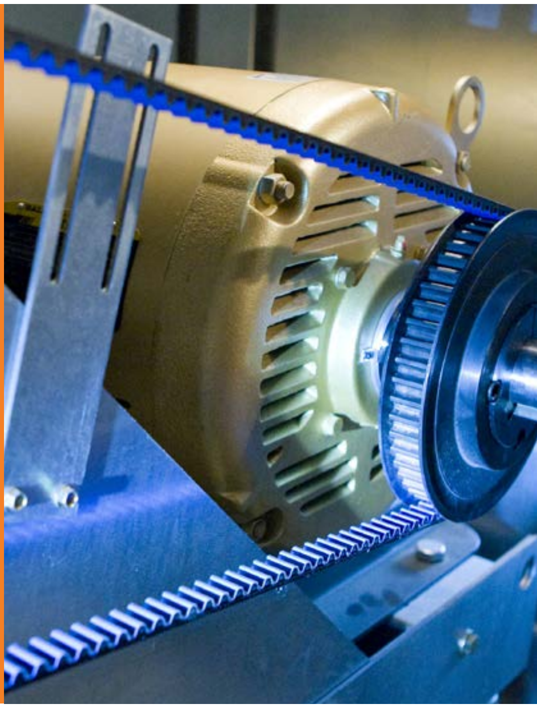
CHAPTER 2

UNDERSTAND YOUR UTILITY BILL



This section illustrates various billing strategies that may be applicable at your facility. Contact your utility account representative for detailed information about your rate schedule.

The first step in reducing energy costs is knowing where your energy dollars are being spent.[2-1, 2-2] How much is used for lighting, air conditioning, air compressors, and refrigeration systems? What portion of the electric bill is for electrical energy consumption (kWh) versus peak power demand (kW)? Are demand charges ratcheted, i.e., are monthly charges linked to the highest 15-minute or 30-minute power draw over the preceding year? Is a power factor penalty or kilovolt-ampere (kVA) charge levied? Are rates seasonally differentiated or higher during certain periods of the day? Is a declining or inverted block structure used for assessing energy charges? The answers to these questions tell you where to look for both energy and cost savings.[2-2]

Helpful Fact

Concepts of Power and Energy

The basic unit of power in electrical terms is a watt (W). Because this unit is very small, a unit 1,000 times as large (the kilowatt or kW) is frequently used. One megawatt (MW) is 1,000 kW. One horsepower is 746 W or 0.746 kW.

Power is the rate of energy use. The amount of energy used by a motor-driven system is directly proportional to the power required by the system times the period of time it is operating. Since power is expressed in kilowatts and time in hours, the conventional unit of energy is kilowatt-hours (kWh).[2-1]

Power and energy measurements are used to determine loads on equipment, energy consumption, operating costs, and to verify proper system sizing and operation. To measure power, use a power meter or take advantage of the fact that power is proportional to the product of circuit voltage (V), amperage or current (I), and power factor (PF).[2-1] For a three-phase system:

$$\frac{P_i = V \times I \times PF \times \sqrt{3}}{1{,}000}$$

Where:

P_i = three-phase power, in kW

V = root-mean-square (RMS voltage, mean line-to-line of 3 phases)

I = RMS current, mean of three phases

PF = power factor as a decimal

Organize Utility Bills and Production Data

Energy accounting involves recording and analyzing both energy use and cost data. This process helps you establish a baseline for energy use at your facility and [2-3]

- Accounts for current energy use
- Identifies areas with the greatest savings potential
- Justifies capital expenditure decisions
- Quantifies the results of investments in energy efficiency measures
- Gains management support
- Detects spikes in demand or increases in energy use
- Identifies billing errors
- Allows for comparison of the energy efficiency of your facility or process with that of similar facilities or processes.

To establish an energy accounting program:

- Locate all meters and submeters within your facility.
- Determine which building(s) or process(es) are served by each meter.
- Obtain copies of all utility bills for at least 1-year.
- Ensure the facility is on the proper utility rate schedule. Often, electrical utilities offer different schedules—such as general service, large general service, primary general service, high-voltage general service, or high-voltage interruptible service—based on the type and reliability of services provided.[2-1] The best schedule for your facility may change over time.
- Obtain monthly and annual feedstock, production, or throughput data at the facility or process level (or both).
- Sort utility bills by building or meter and organize bills into 12-month blocks using meter read dates.
- Organize historical energy and production data so that energy management performance can be measured

Figure 2-1. Energy Use Profile Reports. Illustration from EM4MDS

against a baseline year. Typically, the year before an energy management program begins is selected as the baseline.[2-3]

- Establish a benchmarking metric that makes sense for your business. Benchmarks are often expressed as energy use per unit of product, such as kWh/gallon, kWh per million board feet, or kWh per bale of pulp.

Information about energy use can be presented in a graphical format, as shown in Figure 2-1. For industrial facilities, energy efficiency is properly expressed in terms of the energy performance indicator (EnPI). The EnPI is the energy required per unit of feedstock consumed or energy used to produce a unit of product. Units of production may reference the number of products produced, product weight, or volume. Energy savings are then reflected in a reduction in the energy-intensity ratio—often expressed as million Btu (MMBtu) or kWh/square foot per year or MMBtu, or kWh/unit of production per year.

Electricity use information is often presented in graphs such as the following:[2-3]

- Electricity consumption by month (kWh) for a given facility, meter, or process
- Electrical demand by month (kW)
- Energy and demand costs by month
- “Rolling average” energy consumption
- “Rolling average” energy intensity (MMBtu or kWh/unit of product)
- Facility production by month.

Helpful Tip

The Plant Energy Profiler (ePEP) software tool is available to help companies profile their energy use and identify potential cost savings. It is available from AMO's Energy Resource Center *(www.eere.energy.gov/manufacturing/tech_assistance/ecenter.html)*.

Establish your Facility Baseline Energy Use

An energy baseline is the reference point against which future improvements in plant energy performance must be compared.[2-4] A baseline creates a benchmark for comparing energy performance from year to year.[2-5] The baseline typically encompasses one year's time period, and can be established at the company, facility, department, or process level.[2-4]

Energy use over time is often dependent upon one or more independent variables, such as weather, operating schedule, feedstock variations, or change in product mix. A single or multi-variable regression analysis may be required to track energy use over time.[2-4, 2-6] A regression equation allows for an estimate of future energy consumption based on changes in these independent variables. This technique provides reliable projections of future energy consumption and is necessary for the subsequent determination of energy savings.[2-4]

DOE's EnPI Tool (*https://ecenter.ee.doe.gov/EM/tools/Pages/EnPI.aspx*) assists industries with their energy baselining and regression analysis efforts.[2-7] Access the tool at AMO's Energy Resource Center *(www.eere.energy.gov/manufacturing/tech_assistance/ecenter.html)*. In addition, the U.S Environmental Protection Agency maintains a database of energy performance indicators for many energy-intensive industries. This database allows you to benchmark your facility against similar production plants by making plant-to-plant energy efficiency comparisons. The EPA database may be accessed at *www.energystar.gov/index.cfm?c=in_focus.bus_industries_focus*.

Once a baseline energy consumption profile is established, you should break out the total connected horsepower and estimate the quantity of energy used by type of

Table 2-1. Sawmill Energy End Use Summary.

Process	Electricity Use, kWh	Percentage of Total Use	Cost
Blowers	484,600	4.8%	$12,115
Chippers	101,600	1.0%	$2,540
Air Compressors	1,911,200	19.0%	$47,480
Hog	76,700	0.8%	$1,917
Hydraulic Motors	857,800	8.5%	$21,445
Saw Motors	2,092,000	20.8%	$52,300
Planer Motors	132,700	1.3%	$3,317
Kiln Fans	2,033,800	20.2%	$50,845
Boiler Fans	268,900	2.7%	$6,722
Lights	376,400	3.7%	$9,410
Misc.	1,741,390	17.3%	$43,534

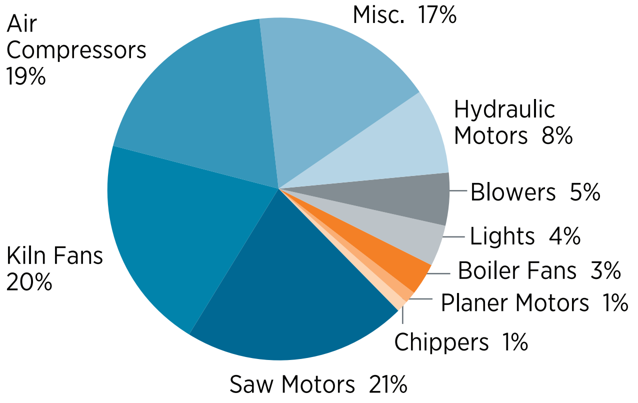


Figure 2-2. Sawmill Energy Consumption Disaggregation.

plant load (pumps, fans, compressors) or determine the annual energy use for each industrial process. You can then focus your efforts on identifying and analyzing energy efficiency opportunities. You should also verify annual energy and cost savings from installed efficiency measures, examine seasonal loads, consumption trends, and anomalies or unexplained peaks in energy use or demand. Such peaks may indicate equipment malfunction or a meter reading error.[2-3] An example of the types of energy end uses at a sawmill is summarized in Table 2-1 and shown in Figure 2-2.

Interpret Utility Charges

A typical electric bill is shown in Figure 2-3. If you look at your own electric bill, it probably tells you how much to pay, but generally does not tell you where the total came from. In contrast, most industrial facility bills include two, three, or more basic charges plus multiple "riders" or energy and demand cost adders.[2-1, 2-2] These different charges vary widely from utility to utility. Therefore, your strategies to reduce energy costs depend heavily upon the rate structure applicable to your facility.

Some industries purchase energy from a third-party supplier with the local utility only assessing transmission and distribution charges. In this case, the energy manager must obtain monthly billing statements from both the local utility and the third-party energy supplier.

While your utility bill indicates how much energy and power you used, the rate structure is your guide for determining how costs are allocated and computed.[2-2] Let's examine the most common charges shown in Figure 2-3, a sample monthly commercial/industrial billing statement. The descriptions below relate to the numbers in Figure 2-3.

1. **Service days:** The number of days in the billing cycle.
2. **Meter number:** The number shown on the face of the meter.
3. **Meter type:** There could be one or more of the following types of meters:
   A. **Energy consumption and demand:** This measures kWh and kW.
   B. **Reactive energy only:** This measures kVARh (kilovolt-amp-hour reactive), which is used to bill for low power factor (generally less than 95%).
   C. **Energy, demand, and power factor:** This meter can measure all three.
4. **Meter reading:** The actual reading taken from the meter.
5. **Multiplier:** The multiplier is stamped on the front of the meter and is used in calculating the kW demand, total kWh consumption, or total kVARh consumption.
6. **Consumption:** The actual meter reading multiplied by the meter multiplier in kWh or kVARh. Reactive power is the nonworking power caused by magnetizing currents required to operate inductive devices such as transformers, motors, and lighting ballasts, and it is used as the basis for power factor charges.
7. **Demand:** This is the actual kW demand and is calculated by multiplying the kW meter reading by the meter multiplier. The demand kW shown is the highest kW recorded by this meter in any 15-minute duration over the monthly billing period.
8. **Power factor (PF):** The PF percentage shown on the bill is determined from the kVARh consumption described above, along with the real (working) power and apparent (total) power. The actual charge for PF below 95% is calculated by multiplying the kVARh consumption by the kVARh rate.
9. **Rate code:** This is the rate that applies to the meter number shown. For customers with multiple meters, more than one rate schedule may apply.
10. **Unit charge:** The rate being charged for the rate code shown. If the rate is not shown, you could have a time-of-use meter. In that case, a second statement is included with your bill that shows the off-peak and on-peak schedule charges.

11. **Service charge:** A monthly charge often referred to as the basic, facilities, or customer charge. It is generally stated as a fixed cost based on transformer size.

12. **Cost adders:** Including taxes and social benefit charges. These can be in the form of $/kWh or $/kW charges, or both.

Service Charge

This monthly charge is often referred to as the basic, facilities, or customer charge. The service charge is designed to recover fixed utility costs associated with activities such as operations and maintenance, administration, metering, and billing. It is generally stated as a fixed cost based on transformer size. Some utilities establish a minimum billing amount or offer a variable service charge, which is dependent upon peak demand.[2-2] One California utility offers a series of pumping rate schedules that have service charges based on the total horsepower of connected load. These service charges apply in every billing period, including months when little or no energy is actually used. Typical service charge structures are given in Example 2-1.

Basic monthly charge: **$760**

Facilities charge: **$2,865/month**

Example 2-1. Basic Service Charge Structures

Account Number	Service Address	Due Date	Amount Due
		09-06-12	50,990.19

Customer Name		
	Previous Charges	62,970.32
	Payments – Thank you	62,970.32 CR
	Balance Forward	.00

Billing Period				Meter Reading		Multiplier	Consumption kWh	Demand kW	Power Factor	Rate Code	Unit Charge	Amount
Start	End	Meter Number	Type	Present	Previous							
07-24-12	08-22-12	219839	kWh	40983	30538	10	104450		89	8		146.23
07-24-12	08-22-12	040597	kWh	98236	7721310	2 0230				34		6,760.30
07-24-12	08-22-12		Dmd	35.75		10		357.5				464.75
07-24-12	08-22-12	116281	kVh	74697	70763	10	39340		91	81		55.00
07-24-12	08-22-12	110989	kWh	96391	27739	10	86520			34		2,370.65
07-24-12	08-22-12		Dmd	24.80		10		248.0				322.50
07-24-12	08-22-12	011252	kWh	10080	9988	40	3680			31		121.44
07-24-12	08-22-12	049054	kVh	39082	36249	100	28830		91	81		396.62
07-24-12	08-22-12	048202	kWh	48924	42490	100	648400			39		10,775.10
07-24-12	08-22-12		Dmd	.01		100		1383.0				815.97
07-24-12	08-22-12	028489	kWh	56973	51611	1	5362			31		176.95
07-24-12	08-22-12	091219	kVh	54215	41505	10	127100		94	61		177.94
07-24-12	08-22-12	089971	kWh	58139	20687	10	374820			35		9,557.91
07-24-12	08-22-12		Dmd	59.64		10		638.4				827.32
07-24-12	08-22-12	090690	kVh	33085	30610	10	24750		78	81		34.65

Total Charges This Period	50,990.19
Service Charge	1,000.00
Amount Due	$51,990.19

Figure 2-3. Utility Billing Statement.

Energy Charges

All utility rate schedules include an energy charge (sometimes called "usage").[2-2] The energy charge is based on the total number of kWh consumed over the billing period. Many utilities offer energy charges that are seasonally differentiated, while some offer rates that vary with the time of day (time of use or TOU schedules). Some utilities charge the same rate for all kWh used, while others charge different rates for different quantities or "blocks" of energy. You must use the "tailblock" or marginal energy cost when calculating the cost-effectiveness and feasibility of investments in energy efficiency measures.

With a declining block schedule, the charge per kWh is reduced for each successive block, making the cost per unit less when more electricity is used.[2-1] With an "inverted" block structure, the unit price increases for each incremental block. You can consolidate meters to take full advantage of declining block rate schedules. A sample declining block rate structure is shown in Example 2-2.

3.636¢/kWh for the first 40,000 kWh

3.336¢/kWh for all additional kWh

Example 2-2. Declining Block Rate Structure

Demand Charge

Peak demand charges can account for more than half of the electric bill in an industrial plant. Demand charges are based on your maximum or peak rate of energy use. The demand charge is similar to a utility "overhead expense" as it is designed to recover costs associated with providing and maintaining enough transmission, switchyard, and distribution infrastructure to meet your peak electrical load.[2-8] Demand charges also cover the costs to the utility of building and operating standby electrical generators or peaking plants that must be brought on-line to meet peak loads. Industrial demands can vary greatly, and utility rate schedules are designed so the customers that create peak demands cover the costs to the utility of serving these peak demands.[2-9]

A typical demand meter averages demand over a specified "demand interval," usually 15 or 30 minutes. At the end of each interval, the meter resets to zero and the measurement begins again.[2-2] The meter then stores or records the largest average demand interval in the billing period. Other utilities base their peak demand on the highest "rolling average" 15- or 30-minute energy use over the billing period. These "sliding window" demand meters record demand and then scan for the largest demand interval regardless of starting time.[2-2] Short periods of intense use, such as an 8-second motor start-up, have little or no effect on recorded demand. A demand meter is depicted in Figure 2-4.[2-3] Utilities are increasingly using digital meters and make billing data available online.

A few utilities base their demand charge on a facility's instantaneous peak power requirement. In this case, short periods of intense use or motor start-ups after a power outage can significantly increase demand. You can eliminate demand spikes by sequencing the start-up of large motors so that their individual peak demands are staggered.

Helpful Tip

Your plant's electricity costs may be reduced by revising operating schedules, replacing inefficient equipment, or selecting a different utility rate schedule that better fits your pattern of electricity use.

Ask your electric utility representative for printed rate schedules that describe the various rates available and to illustrate how charges are calculated. Most electric utilities are willing to change a customer's rate schedule free of charge.[2-4] Some utilities require that customers remain on a rate schedule for a contract period of one year.

Types of Demand Charges

Direct Demand Charges

You may be billed directly for demand charges at a rate ranging from less than \$2/kW per month to more than \$25/kW per month, depending on your utility.[2-2] In the Northwest, both demand and energy charges are higher in the winter months than in the summer months due to the use of electricity for space heating requirements (heat pumps, baseboard heaters, central forced air systems). Winter peak demand charges are rare in the rest of the country as space heating demands are met by natural gas, fuel oil, or wood-fired appliances. In the Atlantic coast, Midwest, South, and Southwest, demand charges peak in the summer because of air-conditioning loads. Utilities often impose seasonally differentiated demand charges or demand cost adders when the facility peak demand occurs during the time of day when the utility load peaks—often during the late afternoon when air conditioning loads are highest.

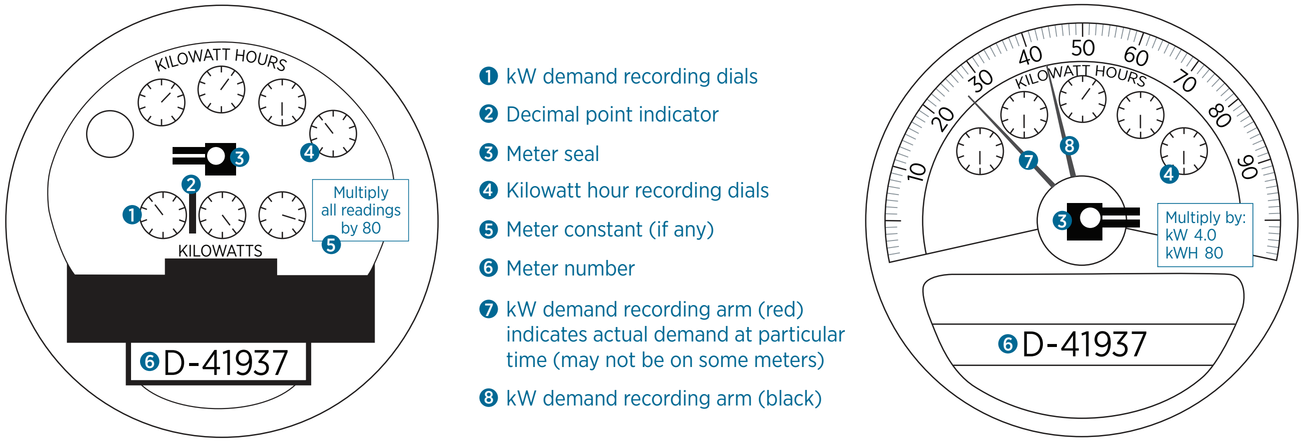


Figure 2-4. Electric Demand Meters.

Like energy charges, demand charges can be levied in a declining or inverted block structure. Sometimes the initial block is offered at no charge, and a fixed charge is assessed for all demand exceeding the minimum value. Typical rate schedule language for direct demand charges is illustrated in Example 2-3.

For each kilowatt of billing demand:

Winter	**Summer**
$12.69	**$13.78**

All kilowatts of maximum demand: **between 7:00 a.m. and 10:00 p.m., Monday through Friday at $7.25/kW**

Example 2-3. Direct Demand Charge

Demand Incorporated into Service Charges

Some utilities incorporate a demand component into their basic charges. Others vary the basic charge based on the facility demand. This type of rate structure is indicated in Example 2-4. This charge may be in addition to other demand charges.[2-2]

If load size is over 300 kW: **$115 + $5.80/kW**

Example 2-4. Incorporation of Demand into Basic or Service Charges

Linkage of Demand and Energy Charges

Some utilities have rate schedules that include demand payments in their energy charges. The energy charge in this case is broken into a block structure where block size varies according to facility demand. For instance, you might pay a higher rate for the first 100 kWh per kW of demand, and a lower rate for all additional energy use. This type of rate structure is depicted in Example 2-5.

6.510¢/kWh for the first 85 kWh per kW of demand but not less than the first 1,000 kWh	Use in excess of 2,500 kWh/month: **$0.058189/kWh**
4.199¢/kWh for the next 8,000 kWh	Use in excess of 190 hours times the peak demand: **$0.051588/kWh**
3.876¢/kWh for all additional kWh	Use in excess of 300 hours times the peak demand: **$0.046789/kWh**

Example 2-5. Linkage of Demand and Energy Charges

Ratcheted Demand Charges

Some utilities use what is called a “ratchet” clause. The concept is that the demand charge should reflect the generating, transmission, and distribution capacity required to meet your peak demand over the entire year, not just for the current billing period. For example, your monthly demand charge may be the greater of the metered demand for all or a percentage of the greatest demand recorded during the preceding 11 months. With this type of rate structure, indicated in Example 2-6, abnormal electrical consumption from using backup equipment during a plant upset or from a plant restart can affect demand charges over an entire year.

Success Story

An examination of a year's worth of billing statements for a regional wastewater treatment plant revealed that demand charges were constant over the last 7 months. This is not expected for a plant with variable inflows, so the energy analyst suspected that the fixed demand charges were due to a peak demand event and a ratchet clause. Plant operators revealed that they had experienced an upset in their anaerobic digesters and lost their supply of biogas that fueled a boiler used for digester heating. A backup 4,000 kW electric boiler was placed into service. The plant operators did not realize that turning this boiler on—for as little as 15 minutes—would result in more than $250,000 in excess annual demand charges. The electric boiler was later decommissioned and replaced with a backup boiler with fuel supplied by a dedicated natural gas pipeline.

The minimum charge is 100% of the maximum demand charge established during the preceding 11 months.

Billing months of April through November:
The highest demand established during the month, but not less than 60% of the highest demand established during the previous winter season.

Example 2-6. Ratcheted Demand Charges

Minimum Demand Charges

Some utilities build a minimum monthly charge into their assessment of demand charges. With this type of rate structure, given in Example 2-7, energy conservation or demand-limiting measures would produce no additional cost benefit once the monthly demand drops below the minimum value.

$5,500 for the first 3,000 kVA or less;
$1.10 for each additional kVA.

The highest average 30-minute demand recorded during the month, or 4,400 kVA, whichever is higher.

Example 2-7. Minimum Demand Charges

Helpful Tip

Reduce ratchet charges by reducing your maximum demand.

When feasible, avoid simultaneously operating large pumps and compressors that are needed only occasionally. Carefully plan when to operate large equipment during the months of your greatest electric demand. The more uniform your month-to-month demand, the closer you will come to only paying for actual demand each month.[2-10]

Success Story

A consultant was analyzing energy costs for three beef packing plants. All were owned by the same parent company and purchasing power from the same utility under the same rate schedule. Average total energy costs were $0.0508/kWh, $0.0467/kWh, and $0.1046/kWh. The third plant, the smallest of the three, had a recorded demand of 317 kW. The utility rate schedule imposed demand charges based upon the greater of 1,000 kW or the metered demand, whichever is greater. With demand charges set at $7/kW/month, switching the third plant to a more favorable rate schedule would save more than $57,000 per year.

Power Factor Charges

Inductive motor loads require an electromagnetic field to operate. Reactive power, measured in kVAR, circulates between the generator and the load to excite and sustain the magnetic field. Reactive power does not perform "work" and is not recorded on the utility's energy or demand meters, yet the utility's transmission and distribution system must be large enough to provide it. Working power, measured in kW, and reactive power together make up the apparent power (measured in kVA).

Power factor is the ratio of working power to apparent power. Power factor measures how effectively electricity is being used. A high power factor indicates the effective and efficient use of electrical power, while a low power factor indicates poor utilization of the incoming electrical current supplied by the utility.[2-11] See **Chapter 9** of this publication for additional information on power factor and power factor correction.

Utilities often assess a penalty for low power factor on their commercial and industrial rate schedules. Various methods exist for calculating the penalty. Understanding your utility's calculation method enables you to determine the benefits associated with potential power factor improvements.

Types of Power Factor Penalties

kVA Billing

As shown in Example 2-8, the utility may measure and bill for every kilovolt-amp of apparent power or primary period (peak) kVA supplied, including reactive current.

Demand charge:
$2.49/kVA of billing demand

Primary kVA charge:
$24,000, which includes 2,000 primary kVA plus $12.10 for each additional primary kVA.

Example 2-8. kVA Billing

Direct Reactive Energy Charges

As indicated in Example 2-9, reactive power may be measured and a reactive energy charge levied (in ¢/kVARh).

Reactive power charge: 0.061¢/kVARh

Example 2-9. Direct Reactive Energy Charges

Demand Billing with a Power Factor Adjustment

In the following calculation, the utility bills the customer at normal demand rates with a demand surcharge or multiplier included to account for low power factor.

$$kW_{BILLED} = \frac{kW_{DEMAND} \times 0.95}{PF}$$

kW_{BILLED} = Adjusted or billable demand

kW_{DEMAND} = Measured electric demand, in kW

PF = Power factor, as a decimal

Equation 2-1

Given a facility power factor of 84%, the utility would obtain a 13% increase in billable demand (95/84) = 1.13. With this form of low power factor penalty, a facility with a metered demand of 1,000 kW would have a billable demand of 1,130 kW. At $10/kW/month, the penalty due to low power factor is 130 kW × $10/kW/month × 12 months/year = $15,600 annually. This low power factor penalty can be eliminated through the installation of capacitors at individual motors or at the plant service entrance.

Example 2-10 shows an example of a rate schedule with a penalty for facilities operating below a power factor of 95%.

The demand charge, before adjustment for power factor, will be increased 1% for each 1% by which the average power factor is less than 0.95 lagging.

The demand charge increases by 1% for each 1% the power factor is less than 85% and decreases by 1% for each percent the power factor is above 90%.

Example 2-10. Demand Billing with a Power Factor Adjustment

Excess kVAR Reactive Demand Charges

With this low power factor penalty method, the utility imposes a direct charge for the use of magnetizing power in excess of some percentage of kW demand. For example, if the charge was $0.60/kVAR for everything over 40% of kW, and the peak load was 4,000 kW, then the utility would provide up to 1,600 kVAR at no cost. Excess kVAR is billable at the specified rate. This type of rate structure is illustrated in Example 2-11.

The maximum 15-minute reactive demand for the month in kVAR in excess of 40% of the kilowatt demand for the same month will be billed at $0.45/kVAR of such excess reactive demand.

Example 2-11. Excess kVAR Reactive Demand Charges

Optional Rate Schedules

Time-of-Use Rates

By charging more during the peak period, when incremental costs are highest, time-of-use utility rates send accurate marginal-cost price signals to customers. Periods of heavy electricity use are typically defined as "peak" hours; periods of lower use are "shoulder" hours, and times of lowest use are deemed "off-peak." Energy charges between peak and off-peak times might vary by more than $0.10/kWh.

Similarly, your demand charges may be computed at a much higher rate if your highest-demand interval occurs during the peak hours.[2-10]

Interruptible, Curtailment, and Customer Generator Rates

At the electric utility's request, customers on interruptible rates must lower their demand. They can do this by turning off some or all of their large electrically driven equipment, or they can use emergency generators or engine-driven pumps instead of utility-supplied power.[2-10]

Helpful Tip

If you are on a time-of-use rate, you should consider shifting as many operations to the off-peak period as possible, along with other demand control measures. Significant investments in added equipment may be justified by savings in energy and demand charges.

If your facility is not on a time-of-use rate, find out whether your electric utility offers such rates. You may be able to reduce costs by switching to time-of-use rates.

Helpful Tip

Find out whether your electric utility offers interruptible, curtailment, or customer generator rates. If you are considering using an emergency generator on a regular basis, analyze operating conditions as well as your ability to maintain the generator. Talk with your utility account representative about a load management agreement.

To obtain interruptible, curtailment, or customer generator rates, the customer enters into a load management agreement to interrupt or reduce plant loads at the request of the power company during the occasional times of peak demand. In return, the power company applies lower rates to the demand charge on the bill for the duration of the agreement. Penalties for nonconformance, however, are high.[2-10]

Use Billing Data to Identify Savings Opportunities

Understanding your electric utility bill—knowing how your demand meter works and how power factor penalties are assessed—is crucial. Energy and demand costs are controllable, and the benefits of implementing energy conservation, demand management, or power factor correction are directly related to the way your facility operates and the structure of your rate schedule. While power factor correction is not generally undertaken for energy conservation reasons, it can result in a reduction in electrical resistance (I^2R) losses within the plant distribution system; it can be very cost-effective and therefore can result in significant reductions in your utility bills.

For a specific utility rate schedule, it is useful to quantify the energy charges and demand charges for a constant 100-kW load operating for a single shift, two shifts, and three shifts, or continuous operation.

Many efficiency measures reduce peak demand and result in energy use reductions. Avoid basing cost savings on "average" energy costs that are based on total monthly or annual utility costs divided by total electrical energy use. Always determine the expected demand reduction and energy savings for an efficiency measure, and then determine cost savings by multiplying the reductions by the appropriate demand and marginal or incremental energy charges.

Another way you can assess the feasibility of demand management measures is by computing your facility load factor. Contact your utility account representative to determine if the utility can provide load data by hour or 15-minute intervals. Often, energy data can be downloaded from "smart" meters. (A smart meter is an electrical meter that records consumption of electric energy in intervals of an hour or less and that provides remote reporting to a Web portal. The portal is often accessible by the facility operator's personal computer (PC), iPhone, iPod, or Android application.

Figure 2-5. Utility Rate Schedule with High Demand Charges

Utility 1			
Large General Service (1,000 kW to 10,000 kW)			
Demand Charge = $13.43/kW/month (Average Annual)			
Avg On-peak Energy Charge = $0.01792/kWh (7 a.m. – 8 p.m.)			
Avg Off-peak Energy Charge = $0.00902/kWh			
	Single Shift	**Two Shifts**	**Three Shifts**
Total Demand Cost	$16,116	$16,116	$16,116
Total Energy Cost	$3,582	$6,275	$10,466
Demand Charges %	81.8%	72%	60.6%

The rate schedule for Utility 1 (shown in Figure 2-5) is characterized by a high demand charge and low energy charges—particularly for off-peak energy. **Demand-related charges account for more than 81% of total utility costs for an industrial plant operating a single shift in this utility's service territory.** Energy charges account for only 19% of a typical utility bill. This brief analysis indicates that consideration of demand management measures, such as load limiting controls, energy storage, or chiller cycling could provide significant benefits at this site. Efficiency measures such as light-emitting diode (LED) parking lot and security lighting would provide energy savings, but minimal cost savings for plants purchasing energy under this rate schedule.

Example 2-12. Breakout of Operating Costs for Utility with High Demand Charges

Load factor (LF) is the ratio of your facility's average to peak demand and indicates how effectively demand is allocated. A low load factor indicates a possible potential for demand reduction through load scheduling that results in "clipping peaks" and "filling valleys." Calculate your monthly load factor for a 12-month period so monthly minimum, maximum, and an annual average load factor can be determined.[2-12] A sample load factor calculation is given in Example 2-14.

Figure 2-6. Utility Rate Schedule with Moderate Demand Charges

Utility 2			
Large General Service			
Demand Charge = $7.71/kW/month (June–Sept.), $6.30/kW/month			
Energy Charge = $0.04225/kWh			
	Single Shift	**Two Shifts**	**Three Shifts**
Total Demand Cost	$8,124	$8,124	$8,124
Total Energy Cost	$8,788	$17,576	$37,011
Demand Charges %	48.0%	31.6%	18.0%

In contrast, demand charges account for less than 50% of total utility costs for a plant running a single shift and purchasing energy and power under Utility 2's rate schedule (see Figure 2-6). Given a three-shift operation, demand charges account for only 18% of total utility costs. In this instance, investing in efficiency measures that save energy would provide significant utility cost reductions.

Example 2-13. Breakout of Operating Costs for Utility with Moderate Demand Charges

If your load factor varies significantly from billing period to billing period, you should carefully review your operation. Many software tools and/or commercial services are available to assist a company in analyzing their energy use patterns. Opportunities for in-plant demand reduction measures likely exist when an annual load factor is less than 80%. In contrast, if your facility has a load factor that is constantly above 80%, there is probably little potential for demand-limiting measures.[2-12]

If your facilities have low load factors, you must determine the load profile—or load variation by time of day or month—for major processes or pieces of equipment within the plant. Compile load data by conducting periodic data logging equipment.

$$LF = \frac{kWh}{kW_{DEMAND} \times 24 \times N} \times 100\%$$

Where:

LF = Load factor in %

kWh = Monthly electrical energy use in kWh

kW_{DEMAND} = Electric demand in kW

N = Number of days in billing period

Sample Billing Information:

Energy Use	Demand	Period
1,132,000 kWh	2,880 kW	30 days

Sample Load Factor Calculation:

$$LF = \frac{1{,}132{,}000}{2{,}880 \times 24 \times 30} \times 100\% = 54.6\%$$

Example 2-14. Determining Your Load Factor

Finally, you will need to become familiar with a host of energy efficiency, load limiting, and other demand-management approaches. Demand management requires that you know how and why tasks are performed at specific times; you can then determine whether any jobs can be scheduled at a different time with little or no effect on production.[2-12] You must also understand the weekly demand profile in each season to determine whether opportunities exist to reduce peak demands or shift load to off-peak periods.

Demand control measures include energy efficiency measures plus equipment scheduling, load shedding, time clocks and duty cyclers, interlocks, programmable controllers, energy management systems, adjustable speed drives, thermal energy storage, and the use of emergency generators to displace large loads during peak demand periods.[2-12]

Helpful Tip

Ask your utility account representative the following questions:[2-10]

- What other rate schedules are available for the plant? Would they be less costly?
- What are the months in the power company's "peak season?"
- Do time-of-use rates exist? How are the peak, shoulder and off-peak periods defined, and what are the corresponding energy costs?
- Is there a demand ratchet clause? Which months in the past year were affected by the ratchet clause? What was the additional annual cost?
- What was the peak month kW demand? How much lower must it be to eliminate ratchet charges in the future?
- Are there any power factor penalties in effect for this plant? What is the annual cost?
- Is a "customer generator" or other load management rate available? What are the requirements? What are the benefits?

Checklist for Electricity Cost Savings

- Compare rate schedules and use the one best suited to your operation.
- Train operators and maintenance workers to be aware of the time of day when utility on-peak charges are imposed. Run motors and other electric loads off-peak whenever possible.
- Encourage routine energy-saving practices and follow recommended maintenance procedures.
- Use sequenced start-ups and avoid scheduling periodic equipment testing during peak hours.
- Install capacitors to reduce low power factor penalty charges.
- Implement demand control measures to reduce peak demand.[2-10]

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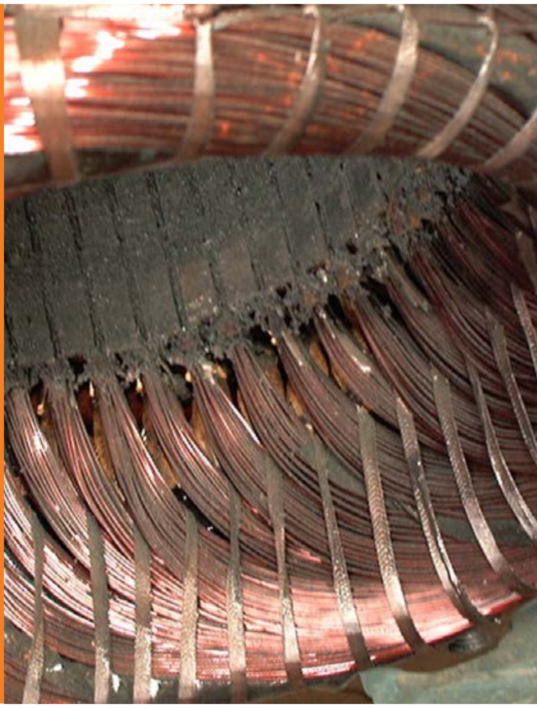
CHAPTER 3

CONDUCTING A MOTOR SURVEY



Conducting a field evaluation of motors is essential in making informed decisions regarding motor selection and use. The amount of money you can save by purchasing a premium efficiency motor instead of an energy-efficient motor depends on the horsepower rating of the motor, annual hours of use, load factor, efficiency gain (at the load point), and the serving utility's charges for electrical energy and demand.[3-1] Field measurements are necessary to establish the load imposed on an existing motor by its driven equipment and to determine motor efficiency at its load point.

Motor Survey Techniques and Information Requirements

It is impossible to manage something when you do not know what you have.[3-1] Experience shows that facility personnel usually underestimate the number of motors in operation at their plant. When motors are actually counted, the actual number of motors can be two-to-three times the original presumption.[3-1, 3-2]

The first step in a motor management program is to prepare a strategy for obtaining nameplate, application, and operating data for both operating and spare motors. Has your plant electrician or maintenance manager compiled an electronic motors database or does he or she maintain an inventory management system?

Many large organizations use CMMS software that contains an equipment list. At many facilities, even when an electronic motor database is available, it is often inaccurate, incomplete, outdated, or otherwise not well-maintained. Medium and small industrial facilities sometimes rely on a card file for record-keeping while a surprising number of facilities have no information on their motor population whatsoever. Do not be surprised if the needed information for each motor is missing or incomplete. Often, only the motor identification number (motor ID), location, horsepower rating, synchronous speed, and full-load current values are recorded and available.

Companies that operate predictive maintenance programs or that employ condition assessment techniques often use a motor analyzer that contains an internal motor database plus a field measurements database that allows for the "health" of individual motors to be monitored and trended. Condition assessment activities often focus on only a subset of a plant's motor population, i.e., on critical motors, larger motors, or motors that are thought to be approaching end of life or where an impending failure is thought to be imminent. Use of common equipment identification numbers allows the condition assessment program's field measurements library to be merged into the broader motor inventory database.

Even when an electronic motors database is available, it is not unusual for the motor's full-load efficiency value to be missing. As one plant electrician stated, "That information is just not useful for me." Motor full-load efficiency values are critical inputs for a motor energy management team as they indicate the efficiency class (standard, energy efficient, premium efficiency) of the motor.

Sometimes, a motor inventory includes only in-service or operating motors. In these instances, nameplate information for spare motors must be obtained. Other times, equipment lists or motor inventories include entries for motors, driven equipment, and process lines that have been taken out of service, are obsolete, or are inoperable.

The assignment of equipment numbers is often chronological. Motors are assigned progressively higher numbers when they are purchased, for example, MO-001… to MO-867. When purchase or installation dates are also available, the motor identification number can then be used to quickly identify the pre-1997 motors that are likely to be of older, standard efficiency designs. Some motor manufacturers stamp the date that the motor was manufactured onto the motor nameplate.

Gathering nameplate information and taking field measurements can be a daunting task as a large industrial facility may have several thousand operating motors plus hundreds of spares.[3-3] While maintenance staff might desire complete information on ALL motors in the plant—for maintenance logging and inventory management purposes—the energy management team may reduce its workload by applying filtering criteria so it focuses on the motors that cost the most to maintain and operate. These are the motors that are large, heavily loaded, run long hours, and are in poor condition.[3-4]

When initiating a motor survey, first consider the single-speed, three-phase, low voltage AC induction motors in a plant that are rated between 20 to 500 horsepower. These motors are covered by the premium full-load efficiency standards. On the initial survey, do not include single-phase, hermetically sealed, submersible pump, DC or synchronous motors, NEMA Design C and D motors, centrifuge, crane/hoist, or punch press motors, motors with synchronous speeds of 720 RPM or lower, motors already controlled by an adjustable speed drive, motors that operate with intermittent, cyclic, or fluctuating loading, or motors designed to operate above 600 V (medium voltage motors).[3-4] Some facilities adopt policies, based upon cost-effectiveness criteria, that call for immediately recycling small general purpose motors—e.g., 50 hp and below—when they fail and replacing them with premium efficiency motor models.[3-5] In this example, those doing a motor assessment should focus on critical general purpose motors without special features that are rated between 60 and 500 hp.

A staff member should be assigned the task of gathering motor nameplate data, operating hours, and application information. This individual should have knowledge of the plant layout and be able to identify motor and equipment types while working safely around electrically energized and operating equipment.[3-1, 3-2]

Motor nameplates are often hidden behind other equipment, painted over, covered with grease or grime, corroded, or even missing. Helpful tools when conducting a motor survey include a degreaser, rags, a wire brush or steel wool to clean nameplates, a mirror to allow for viewing of inaccessible nameplates, and a flashlight.[3-1, 3-2, 3-4] Information on some nameplates is finely scribed and difficult to read without producing a shadowing effect by holding the flashlight at a low angle to the nameplate.

Other motor manufacturers provide nameplates with embossed or raised lettering. Sometimes using a small digital camera or phone camera will show a nameplate that is not easily viewable.

The individual conducting the motor survey should be able to identify motor enclosure types (such as totally enclosed fan cooled [TEFC] and open drip proof [ODP] motors) and to properly recognize NEMA frame, IEC, metric, and various types of special and definite purpose motors such as washdown-duty motors, close-coupled pump motors, brake motors, and right-angle gear drive motors. Several motor types are shown below.

Metric motors are fairly common in North American industrial plants as they often accompany imported equipment. While NEMA frame motors have standardized frame sizes specified in inches, the IEC frame sizes are given in millimeters.[3-6, 3-7] Metric motors are easily recognized by their frame designations (90L, 160M, 250S). General purpose NEMA frame motors usually have a “T” following the frame number (145T, 254T, 404TS). Older motors will have a “U” suffix or no letter at all. While frame sizes for foot-mounted motors correspond fairly closely between the two standards and compatibility tables exist, changing out an IEC motor with a NEMA equivalent may require mounting bolt hole modifications.

TEFC Motor

ODP Motor

Washdown-duty

Photos from Baldor Electric Company

Brake Motor

Shaft dimensions also differ, which may necessitate a new coupling. For face- and flange-mounted motors, NEMA and IEC dimensions are not compatible and it is recommended that standard efficiency IEC motors (IE1) be replaced with premium efficiency IEC motors (called IE3 motors) of the same frame size.[3-6, 3-7] Many motor manufacturers offer premium efficiency IE3 metric motor product lines.

Those doing motor surveys will also encounter dual (230/460 V) or tri-voltage motors (208-230/460 V). These motors can be connected in series or parallel and operate at all indicated utilization voltages. Always indicate the "wired-for" or actual operating voltage when you encounter dual or tri-voltage motors. Record the full-load amperage value from the motor nameplate that is consistent with the wired-for-voltage. For dual- and tri-voltage motors, full-load amp values are given for each voltage and are usually separated by a slash, for example: 60/30. Tri-voltage motors may use both a dash and a slash: 66-60-30 to indicate the full-load amps consistent with each potential utilization voltage.

Depending on the size of the plant and the complexity of the manufacturing process, it may be appropriate to gather information only on the motors that exceed criteria for minimum size and operating duration. Each plant will have to establish appropriate survey and inventory management thresholds. Typical filter or selection criteria include:

- Three-phase, NEMA Design A and B motors
- Larger motors: 20 to 500 horsepower
- General purpose motors with synchronous speeds of 3,600, 1,800, and 1,200 RPM
- Annual operation exceeds 2,000 hours (approximately continuous operation for a plant operating a single shift)
- Motors driving centrifugal loads (centrifugal fans and pumps)
- Constant or varying load (intermittent, cyclic, or fluctuating loads may be candidates for adjustable speed drive operation)
- Older, low-efficiency motors
- "Bad Actors"
- Easy access
- A readable nameplate
- Non-specialty motors.

"Bad Actors" are motors that have suffered repeated failures and may be mismatched to their load requirements or have the wrong level of environmental protection. Conduct a root cause failure analysis for these motors, correct system issues, and consider enclosure upgrades. Chronic motor failures can be due to misuse, misapplication, unsuitability for the operating environment, misalignment/vibration, or poor maintenance practices.

Acquiring Motor Nameplate Data

Begin your motor survey by making copies of the Motor Nameplate and Field Test Data Form, found in Appendix A of this publication. Attach the forms to your clipboard and begin recording data. An experienced motor surveyor can usually gather data for 10 to 12 motors per hour. A typical motor nameplate, as indicated in Figure 3-1, contains both descriptive and performance-based data, such as full-load efficiency, power factor, amperage, and operating speed. You can later use this information to determine the load imposed on the motor by its driven equipment and the motor efficiency at its load point.

Information that you should record is summarized in Table 3-1.[3-8, 3-9] Essential information is listed in bold face. Other information is optional.

Depending on the age of the motor and manufacturer's nameplate marking practices, the motor nameplate might not contain all the information you need. For example, it is not unusual for both efficiency and power factor to be missing. When such data are missing, you will have to assume the motor in question is a standard efficiency motor or attempt to obtain performance information elsewhere. Providing nameplate information to the motor manufacturer is the best place to start.

The motor installation date (used to compute motor age in years and for warranty tracking) and its repair history should also be recorded. You can obtain motor purchase

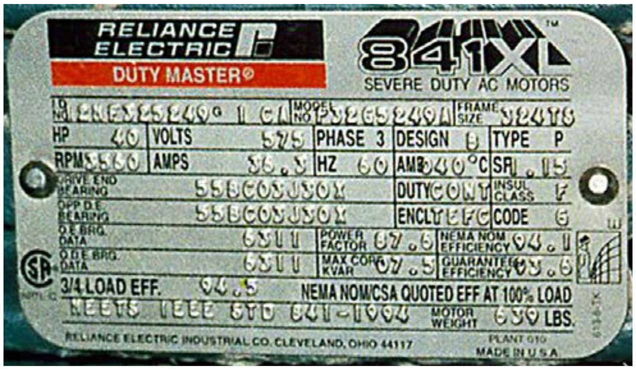


Figure 3-1. Motor Nameplate. Photo from Baldor Electric

Table 3-1. Motor Nameplate Information

Motor Manufacturer	**Location**
Motor ID#	**Motor Model**
Serial Number	**Frame Size**
NEMA Design	Synchronous Speed (RPM)
Horsepower Rating	**Voltage Rating**
Enclosure Type	**Wired-for or Operating Voltage**
Definite or Special Purpose	**Full-load Current**
Full-load Speed (RPM)	Full-load Power Factor (%)
Full-load Efficiency (%)	Service Factor
Insulation Class	kVA Code (locked rotor kVA/hp)
Ambient Temperature (°C)	Bearing Number (drive and ODE)

Table 3-2. Typical Motor Load Types

Variable Torque	Constant Torque
Centrifugal Fans	Conveyors/ Screw Feeders
Centrifugal Pumps	Extruders
Centrifugal Compressor	Blenders/Mixers/ Agitators
Centrifugal Blower	Positive Displacement Pumps
Others	Positive Displacement Blowers
Machine Tools (Lathes, Grinders, Saws)	Rotary Screw Air Compressors
Milling	Reciprocating Air Compressors
Planers	Cranes and Hoists
Sanders	Packaging Machines
	Winders

Quick Fact

The assumption that older motors are standard efficiency models is valid, as proven by motor testing conducted under the 2006 Advanced Energy "100 Motors" study.[3-10] This study, designed to characterize industrial motor performance, involved removing 100 operating motors rated between 50 and 150 hp from a variety of participating industrial plants. The industrial facilities were given free premium efficiency motors as replacements for the motors they contributed to the study. The old motors were shipped to Advanced Energy's motor testing laboratory, where their full and part-load efficiencies were determined using a dynamometer. Out of the 46 motors that did not have an efficiency value stamped on their nameplate, none had a measured full-load efficiency value that met or exceeded the current NEMA energy efficient motor standard.

Table 3-3. Coupling Types[3-5]

Belts and Chains	Gears
V-Belt	Worm
Notched Belt	Helical
Synchronous (Timing) Belt	Bevel
Roller Chain	Helical/Bevel
Silent Chain	Planetary
Flat Belt	Spur
	Cyclodial
Direct Shaft Coupling	Cranes and Hoists

and installation dates and repair histories from maintenance histories from maintenance records, work orders, or from people who have worked at the plant and can recall motor histories. Once motor data have been gathered, a "motor tree" can be used to provide a snapshot of the in-service and spare motor population in the plant (see Figure 3-2.)

Obtaining Application Information

Use the "Motor Nameplate and Field Test Data Form" contained in Appendix A when conducting your motor survey. Describe the motor load (the device being driven), identify the coupling type, indicate whether load modulation devices such as throttling valves or inlet guide vanes are in use, and record the driven-equipment speed. This information should prove useful in future energy management efforts, such as replacing V-belts with synchronous or notched belts or when considering adjustable speed drives for centrifugal equipment with variable flow requirements. See Tables 3-1 and 3-2 for lists of load and coupling types.

The nature of the load being served by the motor is also important. Motors coupled to variable-speed drives, operating with low load factors, or those that serve intermittent, cyclic, or randomly acting loads may not be cost-effective candidates for an efficiency upgrade.

Annual Operating Hour Assumptions

An estimation of annual operating hours and motor load is needed to determine energy and cost savings from any motor efficiency improvement measure. These are critical pieces of information, as energy savings vary directly with assumptions regarding motor load and annual operating hours. At the same time, an evaluation has shown that customer-provided estimates of operating hours can deviate significantly from actual operating hours. One electric utility provided a rebate for the purchase and operation of high efficiency electric motors in commercial and industrial settings. The rebates were awarded at the time of purchase based on customer-supplied operating hour values. To verify to utility regulators that the predicted energy savings were realized, the utility performed field monitoring

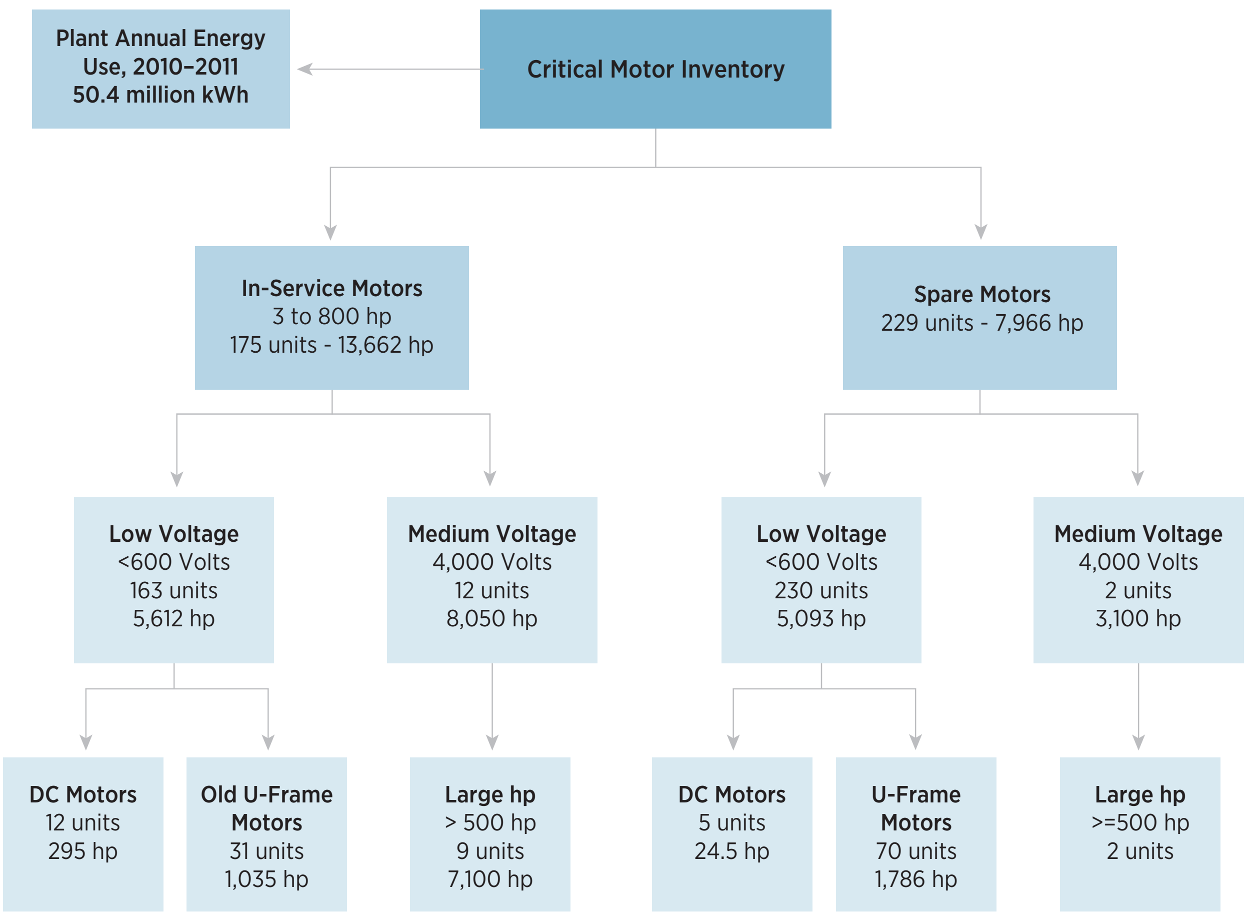


Figure 3-2. A "Motor Tree" for In-Service and Spare Motors

of a subset of the installed high efficiency motors.[3-12] TOU data loggers were installed to record motor start and stop times by sensing the magnetic field created when the motor is operating. Loggers were left on 59 motors (83% were industrial applications) for an average of about 1,600 hours (9.5 weeks). The study found considerable variance between the customer-reported and measured annual operating hour values, and concluded that "customers have a difficult time accurately estimating annual motor run time" and "customers may not be able to accurately estimate operating hours for individual motors." [3-12]

The wide variation between customer-reported and measured motor operating hour values is shown in Figure 3-3. The vertical axis indicates measured operating hour values with the horizontal axis giving customer-reported hours. With this type of plot, good agreement is evident when the value falls on the 45º line. The plot shows that good agreement was rarely achieved. Measured or "true" values ranged from 0 to 8,000 hours per year for a customer-assumed value of 2,000 hours; and from 500 to 8,760 hours for estimates of 6,500 hours.

Assumptions regarding annual motor operating hours can be improved through talking directly with the plant engineer and plant operations staff. Ask how many hours a motor is used on each shift. In food processing plants, the third shift might involve sanitization activities with a different group of motors being heavily utilized. Does the motor operation change on weekends? Is a backup pump

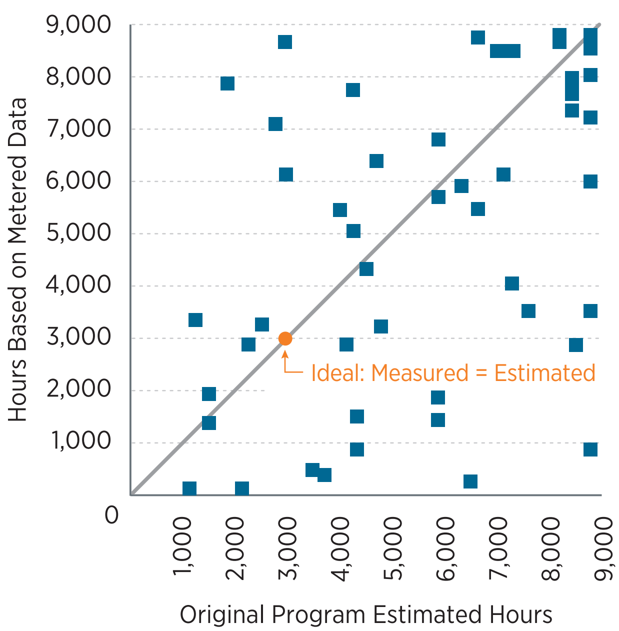


Figure 3-3. Operating Hour Assumptions Versus Measured Values[3-12]

or redundant process train available for a particular application? For instance, a boiler might have two feedwater pumps, with the units rotated each week to equalize wear. This type of operation must be reflected in motor operating hour estimates.

Estimating Motor Load

Various studies have shown that motors are often loaded to between 65% and 75% of their rated output. In this load range, motors often operate at an efficiency that is greater than their full-load efficiency. In addition to monitoring operating hours, the PGE study involved taking field measurements at 39 operating motors. On average, the 39 motors were found to be operating at 74% of their rated horsepower. Field measurements taken of 324 motors at a naval shipyard showed an average load of 67.6%.[3-13] Measurements taken for 102 motors at a pulp mill indicated an average load of 70.1%.[3-14]

To estimate the actual load imposed upon the motor by its driven equipment, it is necessary to measure all of the following at each motor:

- Power, in kW, or
- Line-to-line voltage between all three phases, and
  - Current values for all three phases, or
  - Operating speed of the motor and driven equipment.

The equipment necessary for these measurements includes:

- Voltmeter, multimeter, or power meter
- Clamp-on ammeter
- Power factor meter
- Tachometer.

Meters should be of adequate quality to read true root mean square (RMS) values. This guidebook assumes that the electrician uses meters of adequate accuracy.

Methods of determining motor load from field measurements are given in **Chapter 5**. When the motor operates at a constant load, only one set of measurements is necessary. When the motor drives a variable load or operates at two or three distinct load points, data logging of input power or current over time is required. The electrician can then determine the weighted average motor load or develop a load profile that shows the percentage of operating hours at each load point (for additional information on load profiles see **Chapter 8**).

Motor and driven-equipment speeds must be measured as closely as possible, ideally with a strobe tachometer. Motor speed is important, because a replacement motor should duplicate the existing motor speed. When driving centrifugal loads (fans and pumps), the motor load is highly sensitive to operating speed. A premium efficiency motor usually operates at a slightly higher speed than a standard efficiency motor. The higher speed may result in an increase in speed-sensitive loads; this can negate savings resulting from improving motor efficiency. A speed/load correction is necessary to properly evaluate savings from a premium efficient motor energy efficiency opportunity.[3-15, 3-16]

Quick Fact

Sensitivity of Motor Load to Operating Speed

For centrifugal loads such as fans or pumps, even a minor change in a motor's full-load speed translates into a significant change in load and annual energy consumption. Fan or "affinity" laws indicate that the horsepower loading imposed on a motor by centrifugal load varies as the third power or cube of its rotational speed. In contrast, the quantity of air flow or water delivered varies linearly with speed.

Some premium efficiency motors tend to operate with reduced "slip" or at a slightly higher speed than their standard-efficiency counterparts. This small difference—on the order of 5 to 10 RPM for 1,800 RPM synchronous speed motors—is significant. A seemingly minor 20 RPM increase in a motor's full-load rotational speed from 1,740 to 1,760 RPM can result in a 3.5% increase in the load that the rotating equipment places on the motor, completely offsetting the energy and cost savings typically expected as a result of purchasing a premium efficiency motor.[3-15] See **Chapter 4** of DOE's *Premium Efficiency Motor Selection and Application Guide* for an in-depth discussion of variations in motor load with respect to motor operating speed.

To maximize energy savings with variable torque loads, be sure to select a premium efficiency replacement motor with a full-load operating speed that is the same or less than that of your original motor. When a motor is controlled with an adjustable speed drive, replacement motor full-load speed does not change energy consumption. With belt-driven equipment, motor speed is not critical when you can replace pulleys so that the original rotating equipment speed is maintained.

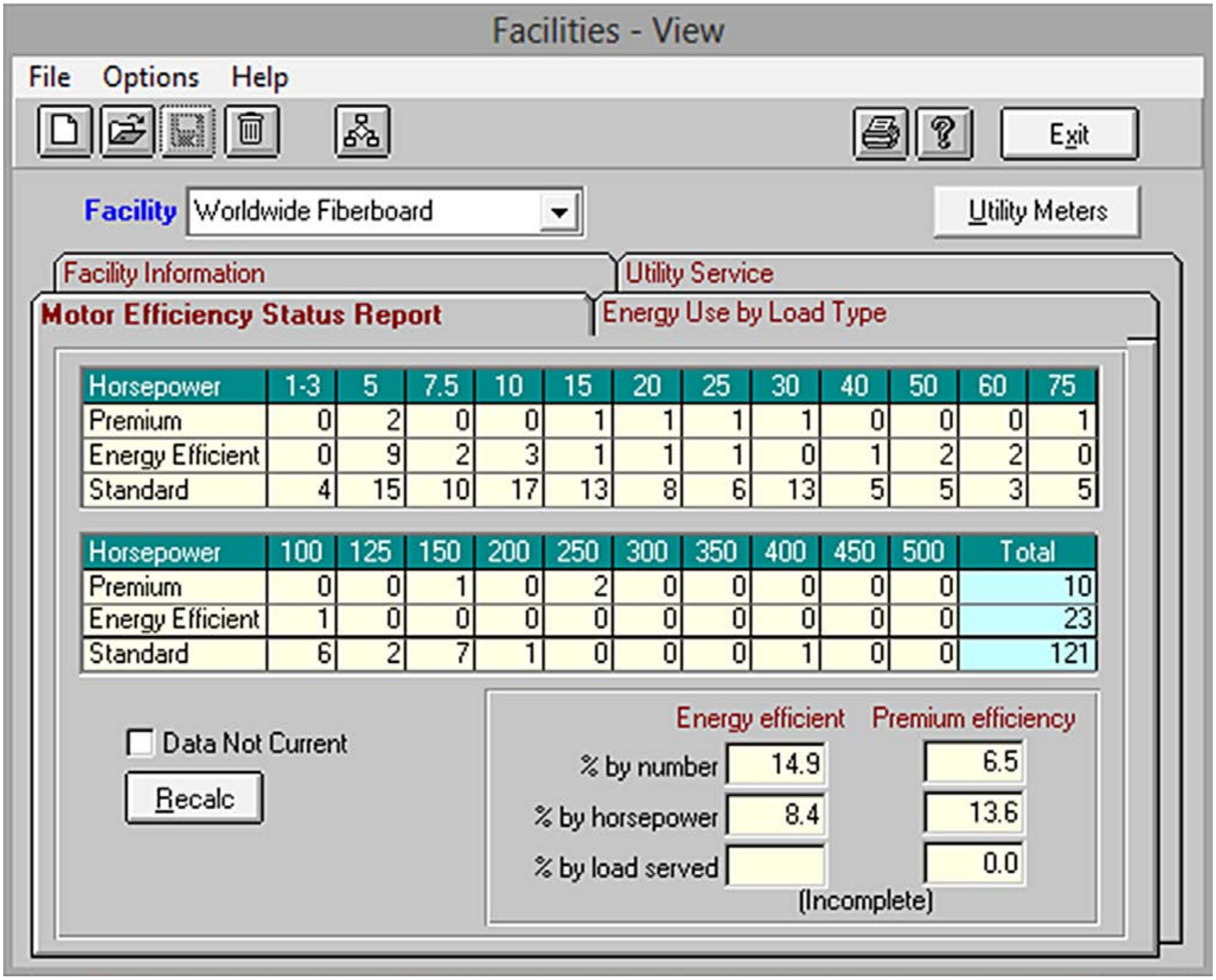
Once you have collected nameplate, annual operating hours, and operating data for each motor in your filtered or short list of motors, you can enter this information into DOE's MotorMaster+ software tool. MotorMaster+ allows users to create an in-plant motor inventory database with a record for each motor. When utility cost data and field measurements are available, the software tool automatically calculates the annual energy use and costs for each motor. When field measurements are entered (see the "Taking Field Measurements" section of this chapter), the software tool determines the load on the motor, average operating voltage, and voltage unbalance. MotorMaster+ load and efficiency estimation algorithms are discussed in the tool users guide and in **Chapter 5**.[3-17] MotorMaster+ motor management capabilities are discussed in detail in **Chapter 7**.

MotorMaster+ also provides a Motor Efficiency Status Report (see Figure 3-4). This report provides a motor efficiency metric for an industrial plant by showing the number of in-service premium efficiency, energy efficient, and standard efficiency motors—by horsepower rating and in the aggregate. When field measurements are provided for all motors, the report shows the percentage of premium efficiency and energy efficient motors by number, by connected horsepower, and by load served.

Taking Field Measurements of In-Service Motors

A diagram of a typical three-phase power system serving a "delta" motor load configuration is shown in Figure 3-5. To evaluate the motor's operation, you will need to collect nameplate data and use a multimeter and analog power factor meter to record voltage, amperage, and power factor on each service phase or leg. It is best to take readings on all three legs and average them. Figure 3-6 indicates how measurements are taken with hand-held instruments. It is also useful to use a strobe tachometer to measure the speed of both the motor and the driven equipment.

Power supplied to the motor can be measured with a single instrument when a "direct-reading" meter is available. The direct-reading meter uses current transformers and voltage leads to reliably sense and display power in watts or kilowatts.



Horsepower	1-3	5	7.5	10	15	20	25	30	40	50	60	75
Premium	0	2	0	0	1	1	1	1	0	0	0	1
Energy Efficient	0	9	2	3	1	1	1	0	1	2	2	0
Standard	4	15	10	17	13	8	6	13	5	5	3	5

Horsepower	100	125	150	200	250	300	350	400	450	500	Total
Premium	0	0	1	0	2	0	0	0	0	0	10
Energy Efficient	1	0	0	0	0	0	0	0	0	0	23
Standard	6	2	7	1	0	0	0	1	0	0	121

Figure 3-4. MotorMaster+ Motor Efficiency Status Report

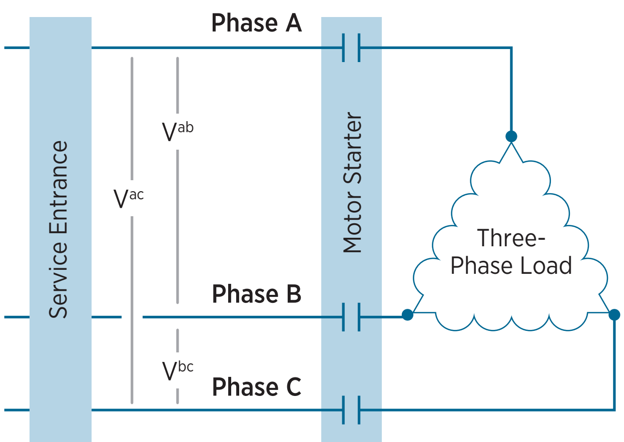


Figure 3-5. Industrial Three-Phase Circuit.
Illustration from EM4MDS

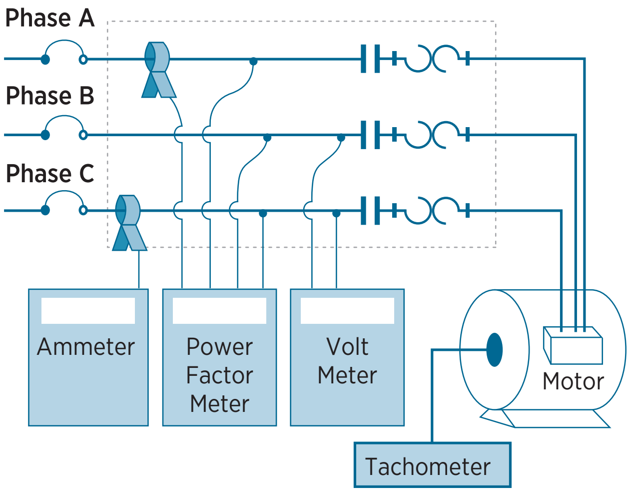


Figure 3-6. Instrument Connection Locations.
Illustration from EM4MDS

Safety Considerations

The field measurements recommended in this document should only be performed by qualified personnel.

Safety is an important consideration when using test instruments. Plant electricians and equipment operators should be well trained in safety procedures and guided by company policies for working close to live circuits and moving machinery. This guidebook will occasionally recommend caution in making certain measurements, but this is not intended to be a replacement for thorough safety training and adherence to company policies. Always follow safety requirements imposed by Occupational Safety and Health Administration and the National Electrical Code (National Fire Protection Association [NFPA] 70E-2012—Standard for Electrical Safety in the Workplace).

The absence of a caution statement certainly does not mean an action is inherently safe, however. Company policies vary depending on plant environment, insurance requirements, government regulations, and management's commitment to safety. **Omit any action in this book that conflicts with your company's safety procedures, conflicts with your safety training, creates exposure beyond your normal workday experience, or simply seems unsafe!**

Particular caution is recommended when working with current- or power-recording devices. Many of these are either assembled from components or designed with the expectation that they will be connected when circuits are not powered, then left alone after they are powered. Some have alligator clips that require your fingers to be close to conductors or that are hard to connect when you are wearing personal protection equipment. Some (particularly multichannel devices intended for research-oriented monitoring) have wiring panels that do not separate 480 V terminal areas from low-voltage sensor wires. Others have metal enclosures that require grounding, which can be a challenge in portable applications. Some have enclosures that may not be sufficient for the environmental exposure they will experience while deployed. Use of any recording device may require that control panel doors be left open, exposing personnel to danger unless you mark the area with ribbon and signs. Most voltage leads are unfused. If possible, leads should be fused, ideally at the clip end. Fuses should be fast-blow and 1/4 amp or less. Even 1/4 amp can be fatal or cause permanent neurological damage if it is sustained for several seconds.

Safety Issues in Data Gathering

Only qualified personnel, following all applicable safety regulations, should make electrical measurements. Whenever possible, de-energize and lock out equipment prior to connecting metering equipment.

- Follow the requirements of NFPA 70E-2012, "Standard for Electrical Safety in the Workplace." This standard defines Personal Protective Equipment procedures and requirements including a hood with a face shield for arc-flash protection, flame resistant clothing, lineman's gloves with leather protectors, safety glasses, and hearing protection.
- Hand-held instruments are not recommended for sensing voltage levels above 600 V.
- The unconnected leads of some current transducers (CTs) can inflict a dangerous electrical shock. This is of significance when you are connecting a CT to a separate readout or recording device. The wound or conventional CTs have either a voltage or current output. The safer (voltage output) type is an internally loaded current transformer, i.e., one that has an internal precision shunt resistor shorting the secondary; the output leads are connected across the internal shunt to provide a low voltage output. The current output type is merely an unloaded transformer, so the output is a current, requiring a current-sensing device.

Always connect a current output CT to the recording device before closing it around a live conductor. Otherwise, dangerously high voltage will appear across the open leads.

Voltage Measurements

Field measurements are necessary to determine the load imposed on an in-service motor by its driven equipment. Once the motor load and the motor's nameplate full-load efficiency values are known, the MotorMaster+ software tool can be used to determine the efficiency at the motor's operating load point.

Utilization Voltage

Utilization voltage should be checked first. A convenient place to take measurements is at a motor starter enclosure. A hand-held voltmeter or multimeter can be used to measure the phase-to-phase voltages. In a three-phase system, the electrician should measure three values: V_{ab}, V_{bc}, and V_{ca} (see Figures 3-5 and 3-6). The voltage unbalance should be calculated.

The utilization voltage unbalance should not be greater than 1%. ***System voltage unbalance and over- and under-voltage problems should be corrected before valid motor energy savings analyses can take place.*** Correcting voltage unbalance greater than 2% may yield greater cost savings than the premium efficiency motor upgrades being considered. A system voltage unbalance exceeding 1% aggravates motor performance to the extent that recorded data may be meaningless.

See DOE's Motor Systems Tip Sheet #7 *Eliminate Voltage Unbalance* *(www.eere.energy.gov/manufacturing/tech_assistance/pdfs/eliminate_voltage_unbalanced_motor_systemts7.pdf)* for information on how determine and correct voltage unbalance.

Service Voltage

When the utilization voltage unbalance is greater than 1%, the electrician must check the voltage values at the service entrance. Optimal voltage limits as defined in ANSI C84.1 "Electric Power Systems and Equipment—Voltage Ranges" call for the utility to deliver power to the 480 V industrial user's service entrance in a range from a low of 456 V to a high of 504 V (480 V ± 5%).

Measurements should be made at or as close to the service entrance as possible. This set of measurements allows the electrician to determine voltage balance as delivered by the utility. If the service voltage unbalance is less than 1%, the utilization unbalance problem is within the plant distribution system. It is then the electrician's responsibility to find and resolve the problem.[3-16]

Service voltage unbalances greater than 1% should be brought to the attention of the local electric utility for correction. Data acquisition techniques discussed in this guidebook are intended for the secondary side of in-plant distribution system power transformers. Hand-held instruments are not recommended for sensing voltage levels above 600 V.[3-16]

Current Measurements

A hand-held ammeter with a clamp-on CT is convenient and effective for measuring the line current. It is only necessary to enclose the conductor within the clamp-on device. You can read the current directly from the meter. Current readings—designated I_a, I_b, and I_c—should be taken for each phase.

Power Factor Measurements

Power factor can be measured with a power factor meter. Measure phase power factor by clamping the current sensing element on one phase while attaching voltage leads to the other phases. Take care to use the proper voltage lead with the current sensing device.

Dedicated power factor meters are becoming less common. They are being supplanted by multifeatured power analyzers that connect in similar ways but provide more data output, e.g., for power factor, kW, and kVAR, and often for the harmonic content of both current and voltage. If you only have data for either power or the power factor, you can calculate the other variable (see **Chapter 5**, Equation 5-1).

Helpful Tip

To conduct a valid motor energy savings analysis, first you will need to correct any system voltage unbalance and undervoltage problems.

Motor Testing Instruments

When shopping for electrical testing instruments, it is easy to be overwhelmed by the variety of choices and the wide range of prices. Three factors tend to affect the price: harmonics handling capability, range, and features. Being a smart shopper requires some knowledge of your plant environment.

Most manufacturers are well represented in industrial catalogs that market instruments. Many manufacturers also use an extensive chain of independent local representatives or “local reps.” It is a good idea to connect with a local rep, because a good local rep can usually supply extensive manufacturer’s information about a product and might also represent competing products for comparison. Ideally, the local rep will have a good understanding of the advantages and disadvantages of each product.

Voltage Meters

Hand-held multimeters usually are used for measuring AC and DC voltage, current, and resistance. The upper voltage range should not exceed 600 V. *Do not attempt to measure higher voltages with hand-held instruments.*

Multimeters are used mainly as voltmeters in an industrial plant. Resistance scales generally do not go low enough for measuring motor winding resistance; at high resistance scales, multimeters do not have sufficient source voltage to measure insulation resistance. The ampere scales are not directly useful for measuring motor current, but many product lines accommodate a clamp-on, AC CT as an accessory. Some manufacturers even have clamp-on accessories that can be used in conjunction with voltage leads for measuring power and or power factor.

Current Meters

Clamp-on current meters (ammeters) are nearly as commonplace as multimeters. Two kinds are in common use. One is a clamp-on CT that feeds an output signal to a separate multimeter for reading on the milliamp or millivolt scale. The other is a self-contained direct clamp-on device. Reading the instrument may be a challenge if you use the latter (the self-contained device), because it might have to be squeezed deep inside a box and oriented at an inconvenient angle to access a conductor. Many instruments accommodate this problem with a pivoting display or a hold switch that can lock the display for reading after the instrument is removed from the conductor. This is an important feature.

Clamp-on current meters sense current in one of two ways—either by means of a simple current transformer or a Hall-effect sensor. The latter is less common and more expensive. Both have operable iron jaws that clamp around the conductor, forming an iron ring in which magnetic flux is induced by the conductor current. The current transformer type has a simple multi-turn winding around the ring to inductively sense the changing flux. The Hall-effect

Voltage Meter. Photo from the Fluke Corporation

Current Meter. Photo from the Fluke Corporation type does not have a winding but rather a narrow gap in the iron ring in which a sensor is placed. The advantage of the Hall-effect sensor is its frequency range. It works for DC and very low frequencies and responds better to higher frequencies. Current and power meters intended for use on either side of variable-frequency drives often use Hall-effect current sensors to handle the severe harmonics and sometimes low fundamental frequencies.

Range is particularly important with ammeters or current transducers. These generally do not span the entire range of plant needs without overloading at the high end or providing poor accuracy at the low end. Take care to select the product or products that will span the necessary range. Power monitors that use a lot of CTs because of unbalanced three-phase capability or multichannel monitoring usually have internally shunted CTs. Often, a wide range of relatively inexpensive CTs can be provided and accommodated with a minor scaling change to the recorder's program.

Physical size is also a limitation. It can be difficult to squeeze large CTs into a small panel. Likewise, it can be difficult to reach around large conductors with CTs of lower range, which tend to be smaller.

Tachometers

There are several types of tachometers. Some require making contact with rotating machinery and others do not. It is best to avoid the contact type.

The most common type of noncontact tachometer is the strobe tach. Strobe tachs are simply electronic strobe lights with an adjustable strobe rate and a very precise readout in flashes per minute. Battery-powered units are somewhat less common than 120 V plug-in models, but for most users the convenience is definitely worth the extra cost. Strobe tachs are very accurate but subject to certain operator errors, which can be reduced with practice. The operator adjusts the strobe rate until the rotating equipment appears to freeze or stop in the light. The speed (measured in RPM) of the equipment should be equal to the strobe rate displayed, but it might also be an integer multiple of the displayed strobe rate. Rotating equipment with repeating features (like blades on a fan) also trick the user. Fluorescent lighting can also cause erroneous readings. Always watch a single feature, like a shaft keyway, and start at the lowest plausible strobe rate.

Some noncontact tachometers are passive, i.e., they do not require the operator to adjust a strobe rate while watching for motion to freeze. These determine speed by sensing reflected natural light or light from an internal source, such as a laser. This can be convenient, but beware of models that require you to stop the machinery and affix a reflector to the rotating part before reading the speed.

Power Logger. Photo from the Fluke Corporation

Power and Power Factor Meters

Many instruments are available that measure power, power factor, or both. The ability to directly read power eliminates the need to calculate it, as described in **Chapter 5**. The simplest instruments have connections as shown in Figure 3-6. Be sure to choose a model with three-phase capability; many instruments can be switched between three-phase and single-phase.

Some three-phase power meters have only one CT and are inaccurate in the presence of a current unbalance. However, many one-CT models have instructions and accommodations for accurately measuring unbalanced three-phase power by moving the CT from one phase to another, making use of a principle called the "two watt meter method." In some instruments this requires summing the readings, while in others the summing is done automatically.

When the load is varying under unbalanced conditions, good results can be obtained only by using an instrument with three CTs. These tend to be more expensive, especially if they are configured as a multifunction power analyzer. The three-CT models are also bulkier and have more components and leads to attach and stow.

Probably the most complicated instrument system likely to be used in a plant is a multichannel power logger. These are available in more than one configuration. In packaged units, there is usually a central module with three voltage leads and a terminal block for two or more trios of CTs.

The central module is both a logger and a transducer; it computes power based upon voltage and the current from the CTs and records the power. All loads must be on the same voltage source, since there is only one set of voltage leads. CTs are marked by phase, so phase identification markings must be present at each load.

Among the many variations on the configuration above, some products consist of a central logger with remote power transducers. Interconnections typically follow voltage, current, or pulse conventions used in industrial programmable logic controller (PLC) systems. Often, they can be equipped with a computer interface, phone modems, or radio transmitters for remote data retrieval. For some tiny battery-powered models, the logger is no bigger than the CTs that attach them. This can be very convenient in an industrial environment, because the entire logger can be closed up in the motor controller box for the monitoring period with no external power connection.

Quick Fact

Power Quality Considerations

If variable-speed drives, induction heaters, or other electronic loads are on the system, expect the presence of voltage harmonics. Extreme current harmonics are present in circuits feeding these loads. The purchaser should describe this electrical environment to the equipment supplier and determine the ability of alternative devices to measure such “dirty” power accurately.

At a minimum, devices that sense voltage or current must operate on a true RMS principle. Those that do not will read inaccurately in the presence of harmonics.

Knowing that an instrument operates on a true RMS principle is not completely sufficient, however, as all instruments are limited by the magnitude and frequency of the harmonics they can handle while still reading accurately. One index of this capability is the crest factor, which is the ratio of peak value to RMS value of a wave form. A perfect sine wave has a crest value of 1.414. True RMS instruments should have a crest factor of 3.0 or better.

Unfortunately, crest value alone is not a complete descriptor of harmonic content. Harmonics caused by most electronic loads cause the current crest factor to be higher and the voltage crest factor to be lower than sinusoidal. An instrument needs to be able to measure accurately across the frequency range of the harmonics. The frequency of harmonics is expressed either in hertz (Hz) or in the order of harmonic. To convert order to frequency, simply multiply by 60. Most high-quality electrical testing instruments specify the frequency range over which their accuracy is maintained.

Motor Analyzers

A variety of products fall under the heading of “motor analyzers.” Several portable units recently appeared on the market to measure motor performance, including motor efficiency. Other efficiency analyzers have gone out of production, perhaps because of a market preference for analyzers oriented more toward predictive maintenance. Several current-signature analysis predictive maintenance analyzers that have entered North American markets have features for estimating efficiency.

All high-end analyzers have connections to the motor to sense current, voltage, and speed. Speed is sensed magnetically or optically. Certain nameplate information must be entered using a keyboard. These devices all require winding resistance, which must be obtained when the motor is shut down; usually the required micro-ohmmeter is built into the tester. Most require no-load or low-load data, which must be obtained with the motor uncoupled and running at idle. Fortunately, none of them require any sort of torque sensor, because it would be nearly impossible to affix one in many field situations.

Motor analyzers are costly sophisticated products; different models have different capabilities and operating requirements. They also vary as to difficulty of use. It is important to study alternatives carefully to find the best match for your budget and staff capabilities.

Metering technologies, equipment, and applications are discussed in DOE’s Federal Energy Management Program publication, *Metering Best Practices: A Guide to Achieving Utility Resource Efficiency* (*www.eere.energy.gov/femp/pdfs/mbpg.pdf*). [3-18]

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CHAPTER 4

MOTOR SPECIFICATION AND SELECTION CONSIDERATIONS

When specifying a motor, the purchaser must indicate the desired motor horsepower rating, nominal voltage, synchronous speed, enclosure type, frame size, insulation class, and efficiency class (or minimum full-load efficiency value). For some applications, definite or special purpose motors are required. This chapter discusses motor choices, performance, and associated efficiency implications.

Motors drive many kinds of loads, which vary greatly as to what they require of the motors. For example, the driven equipment might provide constant fluid flow and be powered by a constant speed general purpose motor. Alternatively, the driven equipment could provide variable flows with flow control provided by an inverter-duty motor controlled by an adjustable speed drive. Loads also might create a constant or cyclic torque demand at a given speed. In comparison to its running torque, a load might have high inertia and require high starting and accelerating torque. The motor might operate in a hostile environment where temperature, humidity, dust, or industrial chemicals are present. And it might need to operate continuously or only occasionally. For every load, a motor must be chosen that can successfully start and run under all conditions—one that can endure the stresses of the specific environment and operating requirements. And it must do this at the lowest possible life cycle cost.

Mandatory Motor Full-Load Efficiency Standards

Mandatory minimum full-load motor efficiency standards currently in effect in the United States have been established through two pieces of legislation:

- Energy Independence and Security Act of 2007 (EISA)
- EPAct

The initial set of federal mandatory commercial and industrial motor performance standards were created by the EPAct. By October 1997, new general-purpose, three-phase induction motors and most definite-purpose motors sold in the United States had to equal or exceed the energy efficient motor full-load efficiency levels prescribed by the EPAct. These efficiency levels were identical with those given in Table 12-6c of NEMA Standard Publication MG 1-1989 Motors and Generators. Motors with full-load efficiency values below the energy efficient standards were deemed "standard efficiency" motors.

The EPAct applied to single speed, general purpose, T-frame, continuous rated, foot-mounted, polyphase, squirrel-cage induction motors of NEMA Designs A and B. Ratings covered under the legislation include 1 to 200 hp; 230/460 V; 3,600, 1,800, and 1,200 RPM motors in open and closed enclosures. These standards applied to motors manufactured alone and as a component of another piece of equipment.[4-1, 4-2]

After the mandatory EPAct standard was established, NEMA in 1994 extended the coverage of the "energy efficient" efficiency standard through 500 hp and renumbered Table 12-6c (it is currently referred to as Table 12-11). From 250 to 500 hp, the term "energy efficient" still designates relatively high-efficiency motors.

In August 2001, NEMA introduced a premium energy efficiency motor standard. Under its program, a motor may be marketed as a premium motor if it meets or exceeds a set of NEMA nominal full-load efficiency levels as defined in NEMA MG 1-2011, Tables 12-12, 12-13, 20-B, and 20-C. These levels are higher than the minimum full-load efficiency standards for energy efficient motors incorporated into the EPAct and listed in MG 1-2011, Table 12-11, and 20-A.

Premium efficiency motor standards apply to NEMA Design A and B, three-phase low voltage induction motors rated from 1 hp to 500 hp and designed for service at 600 V or less (see Table 12-12 of NEMA MG 1-2011). Covered products include foot-mounted motors with speeds of 3,600, 1,800, 1,200, and 900 RPM with ODP, explosion-proof, and TEFC enclosures. Also covered under the standard are severe-duty, washdown, IEC metric frame motors, and brake motors.

A second premium efficiency standard was developed for medium voltage motors (form wound, rated for service at 5,000 V or less). Minimum nominal full-load efficiency values apply to open and enclosed motors rated from 250 hp to 2,500 hp and with synchronous speeds of 3,600, 1,800, 1,200, and 900 RPM (see Table 12-13, 20-B, and 20-C of NEMA MG 1-2011).

Under EISA, the **mandatory** minimum nominal full-load efficiency for low-voltage general-purpose motors with a power rating up to 200 hp was raised to the premium efficiency level as given in Table 12-12 of NEMA MG 1-2011. The premium efficiency requirement applies to motors purchased alone, imported into the country, or purchased as a component of another piece of equipment. EISA is much more stringent than EPAct.

EISA also requires NEMA Design B motors with power ratings between 201 and 500 hp to have a full-load efficiency that meets or exceeds the NEMA energy efficient motor standards (given in Table 12-11 of NEMA MG 1-2011). End users may voluntarily purchase premium efficiency Design B motors in these ratings. The EISA motor efficiency standards took effect in December 2010. Canadian national motor efficiency standards mostly match the EISA requirements (except that they cover all motors rated at <600 V instead of 230/460 V motors).

EISA also expanded the term "general purpose" motor to include a number of motor subtypes that were not covered by the earlier EPAct motor efficiency standards. These motors now must have full-load efficiency values that meet or exceed the NEMA energy efficient motor standards given in Table 12-11 of NEMA MG 1-2011. Motors in the 1 hp to 200 hp ratings that are covered by this mandatory minimum full-load efficiency standard include:[4-3, 4-4]

- U-frame motors
- Design C motors
- Close-coupled pump motors
- Footless (C-face or D-flange without base) motors
- Vertical solid shaft normal thrust motors (P-base)
- Eight-pole (900 RPM) motors
- Polyphase motors with a voltage of not more than 600 V (other than 230 V or 460 V motors). This applies to 200 V and 575 V motor model lines
- Fire pump motors.

Motor efficiency standards are constantly evolving, both in the United States and overseas. The IEC has proposed an above premium efficiency (or IE4) standard level. The minimum full-load efficiency values under discussion may exceed the performance capability of AC induction motor technology.[4-5]

In March 2010, DOE adopted energy efficiency standards for fractional horsepower polyphase and single-phase motors. These standards cover motors operating at 3,600, 1,800, and 1,200 RPM and include capacitor-start/induction run and capacitor-start/capacitor run open motors rated between 0.25 hp and 3 hp. These standards will be applicable beginning March 2015.[4-6]

Motors not Covered by EISA[4-4]

- Single-phase motors
- DC motors
- Two-digit frames (42-48-56)
- Multispeed motors
- Medium voltage motors
- Totally enclosed non-ventilated (TENV) and TEAO enclosures
- Motors with customized original equipment manufacturer (OEM) mountings
- Intermittent duty motors
- Submersible motors
- Encapsulated motors
- Motors that are integral with gearing or brake where the motor cannot be used separately
- Design D motors

Helpful Tip

Always replace single-phase motors with three-phase motors when possible.[4-4]

Full-load efficiency values for a 5 hp 1,800 RPM motor are given below:

- Typical Single Phase: **80.0%**
- Premium Single Phase: **86.5%**
- Premium Three Phase: **90.2%**

Nameplate Efficiency Labeling Protocols

Energy efficiency, annual operating hours, and motor load are the main factors that determine the lifetime cost of owning and operating a motor. Energy costs typically exceed initial motor purchase costs within a year of continuous operation. NEMA Standard MG1 requires that a "nominal" full-load efficiency value appear on the motor nameplate. This nominal efficiency must be derived from tests conducted in accordance with IEEE Standard 112, test method B. The nameplate efficiency represents the efficiency at full-rated load with all three phases at nominal voltage.

Table 4-1. Motor Nameplate Efficiency Marking Standard.
Source NEMA MG 1-2011, Table 12-10

Nominal Efficiency	Minimum Efficiency	Nominal Efficiency	Minimum Efficiency
99.0	98.8	91.0	89.5
98.9	98.7	90.2	88.5
98.8	98.6	89.5	87.5
98.7	98.5	88.5	86.5
98.6	98.4	87.5	85.5
98.5	98.2	86.5	84.0
98.4	98.0	85.5	82.5
98.2	97.8	84.0	81.5
98.0	97.6	82.5	80.0
97.8	97.4	81.5	78.5
97.6	97.1	80.0	77.0
97.4	96.8	78.5	75.5
97.1	96.5	77.0	74.0
96.8	96.2	75.5	72.0
96.5	95.8	74.0	70.0
96.2	95.4	72.0	68.0
95.8	95.0	70.0	66.0
95.4	94.5	68.0	64.0
95.0	94.1	66.0	62.0
94.5	93.6	64.0	59.5
94.1	93.0	62.0	57.5
93.6	92.4	59.5	55.0
93.0	91.7	57.5	52.5
92.4	91.0	55.0	50.5
91.7	90.2	52.5	48.0
		50.5	46.0

A somewhat complex set of procedures is used to determine the exact nominal efficiency that will appear on the nameplate for each model line. IEEE 112B testing is conducted on a population of motors within each model line, and an "average efficiency" is determined as the arithmetic mean efficiency of that population. NEMA recognizes that manufacturing tolerances will lead to variations in efficiency for individual motors within a population. NEMA has confronted this issue by defining a lower "minimum" efficiency that must be equaled or exceeded by all motors in a motor model line.

One might expect that the nominal (nameplate) efficiency would be the same as the average efficiency, but it is not. NEMA MG 1 has established efficiency bands topped by specific nominal efficiencies that can be placed on the nameplate. Those bands are reproduced here as Table 4-1. After determining the actual average efficiency, the manufacturer must label the motor with a nominal efficiency from the table that is equal to or less than the average efficiency. For every nominal efficiency band, the table contains a corresponding minimum efficiency value.

The purchaser can be comfortable using NEMA nominal efficiency from the nameplate in making motor purchasing decisions. This is not to imply that all new motors arrive free of manufacturing flaws that reduce efficiency and other performance parameters. Such flaws appear periodically, and purchasers should conduct receiving inspection tests to check for them. Record nameplate information into your motor tracking system when new motors are delivered.

For nearly every category and rating of motor there are multiple manufacturers, and each one offers several models. The various models span a range of nominal efficiencies. It is important to know what efficiencies are available within each group of competing models and how to specify the highest economically justifiable efficiency. This task is made easier by the adoption of mandatory minimum full-load efficiency standards. Standards also provide a basis for various premium or enhanced efficiency motor rebate or incentive programs sponsored by electric utilities.

Horsepower Ratings

Motor "size" generally implies a shaft output power or horsepower rating. IEC metric motors are rated in kW. Motors can be oversized and still serve a load satisfactorily and (to a point) efficiently. They deliver the horsepower the load requires, not their rated horsepower. Most motors above the fractional horsepower range maintain a high efficiency to about 50% load. You can find full and part-load efficiencies down to 25% of full-load in MotorMaster+. There are some advantages to moderate motor oversizing. You have a greater margin of safety from overheating, a "cushion" to accommodate errors in estimating or load spikes, faster acceleration to operating speed, greater tolerance to undervoltage operation, and potentially higher efficiency.

Motors typically operate at their highest efficiency when loaded to about 70% to 80% of full-load. This performance characteristic occurs because above 60% load the motor's shaft or output horsepower varies linearly with current. Resistance losses, however, vary with respect to the square of the current. Motor efficiency is equal to output (output + losses) and efficiency increases when resistance losses are reduced faster than the delivered output.

Underloaded motors operate at lower power factor, although this disadvantage is minor if power factor is corrected with capacitors, low power factor is not penalized by the utility, or the motor is controlled by an adjustable speed drive that corrects for power factor. Oversized motors draw more current because of their reduced power factor at part-load. In addition, they draw a higher starting current, because starting current is a property of the motor and is not affected by the magnitude of the load. Motor efficiency and power factor as a function of load are shown in Figure 1-1. Oversized motor performance is discussed in detail in AMO's *Premium Efficiency Electric Motor Selection and Application Guide*.[4-7]

Synchronous Speed

AC motor speed is controlled primarily by the stator winding configuration, which determines the number of magnetic poles in the stator. The rotational speed of the magnetic field is known as the motor's ***synchronous speed***, and it is always 120 times the line frequency divided by the number of poles. Wherever a 60 Hz line frequency is used, this works out to speeds of 3,600 RPM (two poles), 1,800 RPM (four poles), 1,200 RPM (six poles), and 900 RPM (eight poles). In countries with a 50 Hz power supply, 2-, 4-, 6- , and 8-pole motors would rotate at 3,000, 1,500, 1,000, and 750 RPM, respectively.

For all AC motors except the commonplace induction motor, rotor and shaft speed are exactly the same as synchronous speed. Induction motors have ***slip***; they run slower by a few percent than synchronous speed. That is why induction motor nameplate full-load speeds are a little lower than the motors' synchronous speeds.

Slip is the difference between a motor's synchronous speed and its operating speed. The motor's full-load speed is its synchronous speed less the slip that occurs when the motor is fully loaded. Slip varies from less than 1% of synchronous speed for large premium efficient motors (and lightly loaded motors) to greater than 5% for many fractional horsepower motors and motors used in special applications. Slip represents one of several energy loss categories in a motor. For this reason, induction motor designers try to keep slip low; however, manufacturing costs and other operating parameters, like starting current and torque, tend to move in the wrong direction if slip is too low.

Synchronous speed minus the slip is the motor operating speed. Operating speed is very important in centrifugal pump and fan applications where input power requirements are speed sensitive. For centrifugal fans and centrifugal circulating water pumps (i.e., pumps used in a non-static lift application), fluid flow is proportional to the shaft speed; the power requirement, however, is proportional to the cube of the shaft speed. Even small speed differences are significant as a 1% increase in operating speed shifts the fan or pump performance curve so the system curve intersects it at different location. The result is higher flow, and a higher discharge or outlet pressure resulting in an overall 3% power increase. Energy use increases even in applications like a pump filling a tank—where the tank will be filled in less time.

For a given motor, speed and slip are not constant; they vary with load and voltage. See **Chapter 5** for information on determining motor load from measurements of its speed.

Full-Load and Locked-Rotor Torque

All motors of the same horsepower and speed rating have the same full-load torque. They differ, however, in the torque they can provide at start-up and throughout acceleration. NEMA has several three-phase induction motor design designations, denoted by the letters A, B, C, and D. These should not be confused with other parameters that NEMA also classifies by letter, such as locked-rotor current and insulation temperature tolerance. A variety of motor performance parameters are set by the design letter, horsepower rating, and synchronous speed of a motor, but the most important is the minimum delivered torque at start-up and during acceleration of the motor. Figure 4-1 shows typical torque-speed curves during acceleration of motors of different NEMA designs.

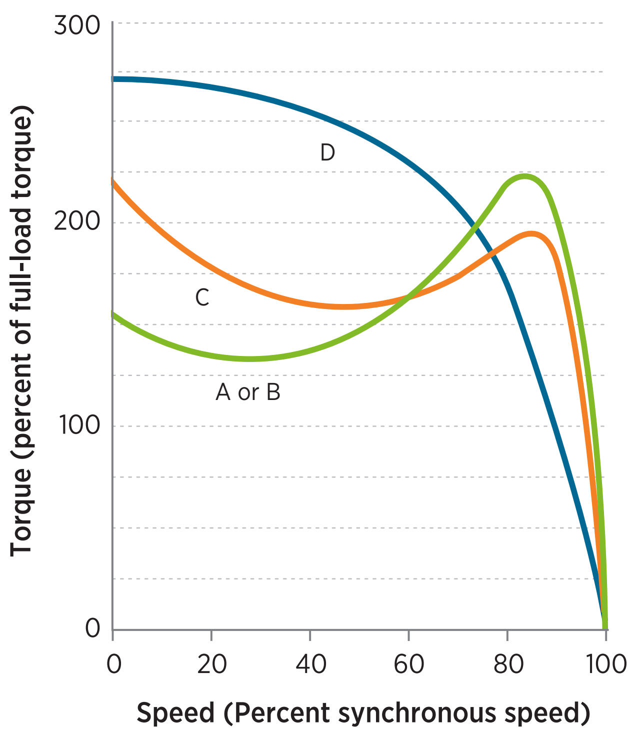

Figure 4-1. Torque-Speed Curves for NEMA Design A-D Motors

At the moment acceleration begins, the torque developed is called the "locked-rotor torque." For motors in the NEMA Design A, B, and C categories, torque actually drops somewhat as acceleration begins and reaches some minimum value, which is still higher than the steady-state torque at rated load and speed. This minimum is called the "pull-up" torque. As acceleration proceeds, a torque maximum called the "breakdown" torque is reached. The load also has a speed torque curve. When overlaid, the motor torque curve must be greater than the load torque curve at every speed point. Otherwise, the motor will overload and stall before reaching its breakdown torque.

Even within a NEMA Design letter category, motor models of the same rating can differ in locked rotor and accelerating torque—remember that NEMA only specifies **minimum** locked rotor and pull-up torque values that a motor must equal or exceed. If starting or accelerating torque is critical, you can obtain measured locked rotor torque values from manufacturer's data or from MotorMaster+.

NEMA has placed a maximum limit on the starting current of Design B, C, and D motors (which are the most common). Design A motors are quite similar in performance to a Design B motor, but there is no limit on starting current. Design C motors are designed for higher starting torque and are most often used in material handling applications, when an initial high torque is needed to overcome static friction or material compaction. Design A through C motors all have the same maximum allowable slip, but Design C motors tend to exhibit higher slip within that limit.

Design D motors are high-slip machines for use on loads that cycle several times per minute in their torque demand. Such applications include punch presses and rocking beam oil well pumps. In these applications, a flywheel is used to supplement the motor through the high torque moments; otherwise, it would stall. The flywheel decelerates as a result of contributing momentum to the load shaft during the high torque moments. The motor re-accelerates the flywheel during the low torque demand part of the cycle. Figure 4-1 makes it clear that designs other than Design D would reach a breakdown torque with very little deceleration of the load. A Design D motor's breakdown torque is essentially the same as its locked-rotor torque.

Never use a Design C or D motor in an application where a Design A or B motor would work because Designs C and D motors are considerably less efficient.

Full-Load and Locked-Rotor Current

A motor's full-load current or amperage rating is important for sizing the electrical service and protection. At rated load, the current rating is listed on the nameplate in amperes. For multivoltage motors, the amperages for each connectable voltage are given in the same sequence as the voltages to which they correspond.

It is very important to provide for the high locked-rotor current that occurs when a motor starts and accelerates. Locked-rotor current varies but tends to be around six times the rated full-load current. The code letter that pertains exclusively to locked-rotor current is usually just designated "Code" on the nameplate, and it should not be confused with the NEMA Design letter. These letter codes are associated with a range of kVA per rated horsepower.

To determine the actual locked-rotor amperage rating, obtain the code letter from the nameplate or catalog and look up the kVA per horsepower (kVA/hp) corresponding with the code letter from Table 4-2, which has been taken from NEMA MG 1. Next, multiply the table number by the rated horsepower of the motor and then divide by 1.732 times the motor voltage rating in kV, e.g., 0.46 kV for a 460 V motor. MotorMaster+ provides the locked-rotor or starting current for new motors directly in amps. For multi-voltage rated motors, MotorMaster+ lists the

Table 4-2. NEMA Locked-Rotor Code Letter Definitions

Letter Designation	kVA/hp*	Letter Designation	kVA/hp*
A	0.00–3.15	K	8.0–9.0
B	3.14–3.55	L	9.0–10.0
C	3.54–4.0	M	10.0–11.2
D	4.0–4.5	N	11.2–12.5
E	4.4–5.0	P	12.4–14.0
F	5.0–5.6	R	14.0–16.0
G	5.5–6.3	S	16.0–18.0
H	6.3–7.1	T	18.0–20.0
J	7.1–8.0	U	20.0–22.4
		V	22.5 and up

*The locked kVA per horsepower range includes the lower figure up to, but not including, the higher figure. For example, 3.14 is designated by letter A and 3.15 by letter B.

full-load and locked-rotor amperage for the highest voltage connection. The amperage is inversely proportional for other potential utilization voltages, e.g., if the full-load current is 50 amps with the 460 V connection, it will be 100 amps with a 230 V connection.

With the efficiency improvements of the last several years, NEMA and the National Electrical Code (NEC) have dealt with one more important category of motor current. This is the ***instantaneous inrush current***, and it should be carefully distinguished from ***locked-rotor current***. Locked-rotor current is an RMS current, which means current has to have been established for at least one full AC cycle before it can be defined or measured. Instantaneous inrush current is the peak instantaneous current that occurs on any phase within the first half-cycle after starting contacts close.

A premium efficient motor is liable to have a greater instantaneous inrush current than a standard efficient counterpart with the same locked-rotor current. No NEMA Design limits instantaneous inrush current although many Design B motors must be reclassified as NEMA Design A motors when redesigned as a premium efficient motor. This is of no consequence in most situations because of its brief duration. But inrush current can be a problem in situations where so-called instantaneous magnetic-only circuit protectors are used. If nuisance tripping occurs after an efficiency upgrade where instantaneous circuit protectors are used, consult Section 430 of the latest revision of the NEC. The code has been modified to allow adjustments to a higher trip setting when nuisance tripping occurs. For additional information, see DOE Motor Systems Tip Sheet #6, *Avoid Nuisance Tripping with Premium Efficiency Motors* (www.eere.energy.gov/manufacturing/tech_assistance/pdfs/avoid_nuisance_motorsys_ts6.pdf).

Frame Size

Motor frame sizes were not standardized prior to 1952. In 1952, NEMA established a set of standards for U-frame motors. As upgraded insulation systems were developed, T-frame motor standards were introduced in 1964. T-frame motors are smaller than U-frame motors of a comparable horsepower rating. U-frame motors can be identified by the frame designation on the motor nameplate (for 1- to 100-hp motors, 182, 184, 213, 215, 254U, 256U, 284U, 324U, 326U, 364U, 365U, 404U, 405U, 444U, 445U). T-frame motors have the letter "T" following the frame number (i.e., 143T, 145T, 182T, 184T, 213T, 215T, 254T, 256T, 284T, 284T, 324T, 326T, 364T, 365T, 404T, 405T). A frame number ending in TC designates a 'C-face' motor, while LP, HP, or VP indicates a P-base or vertical shaft motor. Close-coupled pump motors have frame numbers ending with JP or JM.

For small machines, the frame number is 16 times the distance of the shaft centerline height above the motor baseplate (when measured in inches). For larger machines (140 frame and above), the first two digits of the frame number are four times the distance that the shaft height is above the motor baseplate (when measured in inches). With IEC motors, the frame designation indicates the shaft height in millimeters (mm).

To be assured of a proper fit without having to modify the mounting, purchase replacement motors with the same frame size designation as that of the original motor. Premium efficiency T-frame and U-frame motors are available in the same range of frame sizes as the older motors they replace. Frame size is predominantly associated with the dimensions of all mounting and contact surfaces, including the shaft height and diameter.

While premium efficiency U-frame motors are available, they are considerably more expensive than equivalent rated T-frame motors. Frame adapters or transition bases are available so that old U-frame motors can be replaced by premium efficiency T-frame motor models. The transition bases accommodate the mounting bolts for both the T-frame and U-frame motors and line the T-frame motor shaft height up with the driven equipment shaft.[4-8] Some industries have replaced all of their older U-frame with modern T-frame motors to reduce their spares inventory.

Some exterior dimensions that do not pertain to mounting are not controlled by frame size, so take care that your new motor does not interfere with structures having close clearances. Premium efficient motors sometimes extend beyond the opposite-drive-end mounting feet.

Enclosure Type

Various enclosure designations pertain to the design features that facilitate the cooling of the motor and protect it from the surrounding environment. The most common NEMA enclosures are TEFC and ODP. NEMA's MG 1 describes the circumstances and criteria for using each type of enclosure. Basically, an ODP enclosure permits the passage of cooling air around the windings of the machine. The ventilation openings are constructed so operation is not interfered with when drops of liquid or solid particles strike the enclosure at any angle from 0° to 15° from the vertical. A TEFC machine is enclosed to prevent the exchange of cooling air between the inside and outside of the enclosure. The TEFC enclosure is designed to prevent dust from interfering with machine operation. NEMA also includes a "suggested standard for future design" that follows the lead of the IEC. The IEC ingress protection (IP) enclosure rating approach assigns numeric values that indicate the degree of protection against intrusion of solid objects and the ingress of liquids. For most industrial applications, IP22 relates to ODP motors, IP54 to TEFC, IP45 to weatherproof, and IP55 to washdown duty motors.[4-9]

Hazardous location is another important type of motor enclosure (often referred to as "explosion-proof" motors by manufacturers). They are designed for use in harsh industrial environments that contain hazardous gas and vapor that may have explosive properties. A common misperception is that explosion-proof motors are sealed so tightly that no dust or other contaminants can enter. This is not true. The motor can breathe as the air inside expands and contracts, just as a TEFC motor does. The explosion-proof motor has a "flame path" at the endplate to frame joint to quench any flames from an internal fire or arcing fault before it can propagate and ignite flammables in the air surrounding the motor.

Explosion-proof motors are designated under the NEC as compatible for use in Class 1 Group C and D environments, or are rated for operation in Class II Group E, F, and G environments. Equivalent IEC motors are designated as "flame-proof" motors.[4-9] Premium efficiency explosion-proof motors are available from most manufacturers. Always make sure that a standard efficiency explosion-proof motor is replaced by a premium efficiency motor that is rated for the same environment.

Additional enclosure types include totally enclosed non-ventilated (TENV), TEAO, totally enclosed blower-cooled (TEBC), and weather protected (WP).

Insulation Class

NEMA has established standards for motor insulation system design, temperature rating, and motor thermal capacity. Four classes of insulation are available, each with an allowable temperature rise above ambient (ambient is defined as 40ºC or 104ºF) and maximum allowable temperature. A motor's insulation class is a system rating based on insulation materials including the wire coatings, varnish, slot liners, lead wire insulation, and topsticks. Motor insulation systems are based on temperature endurance for 20,000 hours and are designated as class A, B, F, or H. Class A insulation systems are shown by experience or test to have a suitable operating life when operated at a maximum temperature of 105ºC. A Class B system shows acceptable thermal life when operated at 130ºC; a Class F system can be operated at a limit of 155ºC; while a Class H system can be operated at a limiting temperature of 180º C.[4-1] Class A insulation is rarely used today; Class B is the "baseline" insulation system; while Class F insulation is considered standard for most energy efficient and premium efficiency motors.

Because a motor is supplied with a Class F or H insulation system does not mean that the motor's actual temperature rise or operating temperature increases. A higher insulation class can result in an improved insulation life. The life of the insulation doubles for every 10ºC cooler the motor runs relative to its maximum thermal limits.

Service Factor

The service factor of an AC motor is a multiplier which, when applied to the rated motor horsepower, indicates a permissible loading for continuous operation at rated load under usual service conditions. While operation within the service factor is permissible, it is not recommended as a motor operating continuously at any service factor greater than 1 will have a reduced life expectancy. Both insulation life and bearing life are reduced by service factor loads. Most general purpose motors have a service factor of 1.15. This service factor is reduced to 1.0 when the motor is controlled by an electronic pulse-width modulated variable frequency drive.

Definite and Special Purpose Motors

A general purpose motor is an AC induction motor designed according to NEMA (or IEC) standards to meet a broad variety of applications. A definite purpose motor is produced in standard ratings and with standard operating characteristics for particular applications or other than usual service conditions.

A special purpose motor is designed with special operating characteristics for a particular application. Examples include inverter-duty motors, brake motors, and integral gear motors.

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CHAPTER 5

MOTOR LOAD AND EFFICIENCY ESTIMATION TECHNIQUES

To compare the operating costs of an existing standard efficient motor against those of a premium efficient replacement unit, you must determine operating hours, motor load, and the efficiency of each motor at its load point. Part-load is a term used to describe the actual load served by the motor in comparison to the ability of the motor to deliver shaft horsepower at its rated full load. The actual motor load can be estimated using input power, amperage, or speed measurements. Several load estimation techniques are briefly summarized.

Input Power Measurements

When "direct-read" power meters are available, use them to measure the input power supplied to the motor and the load that is imposed upon the motor by the driven equipment. With measured parameters taken from hand-held instruments, you can use Equation 5-1 to calculate the three-phase input power to the loaded motor. You can then quantify the motor's part-load by comparing the measured input power when operating under load with the power that would be required if the motor was to operate at rated capacity (from Equation 5-2). The relationship that estimates motor loading based on power measurements is shown in Equation 5-3.

$$P = \frac{V \times I \times PF \times \sqrt{3}}{1000}$$

Where:

P	=	Three phase power in kW
V	=	RMS voltage, mean line-to-line of three phases
I	=	RMS current, mean of three phases
PF	=	Power factor as a decimal

Equation 5-1. Using Field Measurements to Determine Motor Input Power

$$P_R = \frac{HP \times 0.7457}{\eta_R}$$

Where:

P_R	=	Input power at full rated load in kW
HP	=	Nameplate rated horsepower
η_R	=	Efficiency at full rated load

Equation 5-2. Calculating the Full-Load Motor Input Power

$$LOAD = \frac{P}{P_R} \times 100\%$$

Where:

Load	=	Output power as a % of nameplate rated power
P	=	Measured three phase power in kW
P_R	=	Input power at full rated load in kW

Equation 5-3. Estimating Motor Load using the Input Power Measurements

An existing motor is a 40-hp, 1,800-RPM unit with an open drip-proof enclosure. The motor is 12 years old, has a full-load efficiency of 90.2%, and has not been rewound. The electrician makes the following measurements:

Measured Values:

V_{ab} = 467 Volts	I_a = 36 Amperes (A)	PF_a = 0.75
V_{bc} = 473 V	I_b = 38 A	PF_b = 0.78
V_{ca} = 469 V	I_c = 37 A	PF_c = 0.76

Average Voltage = (467 + 473 + 469)/3 = 469.7 V

Average Current (I) = (36 + 38 + 37)/3 = 37 A

Power Factor (PF) = (0.75 + 0.78 + 0.76)/3 = 0.763

Equations 5-1 through 5-3 reveal that:

Input Power
$P = 469.7 \times 37 \times 0.763 \times \sqrt{3} / 1000 = 22.9$ kW

Power at Rated Load
$P_R = 40 \times 0.7457 / 0.902 = 33.1$

Load = P / PR = (22.9 / 33.1) × 100% = 69.3%

Example 5-1. Input Power and Load Calculations

Line Current Measurements

The current load estimation method is recommended when only voltage and amperage measurements are available. The amperage draw of a motor varies linearly with respect to load, down to about 50% of full load (see Figure 5-1). Below the 50% load point, power factor degrades due to reactive magnetizing current requirements and the amperage curve becomes increasingly nonlinear. Below 50% load, current measurements are not a useful indicator of motor load.

$$\text{Load} = \left(\frac{I}{I_R} \times \frac{V}{V_R}\right) \times 100\%$$

Where:

Load = Output power as a % of rated power

I = RMS current

I_R = Nameplate rated current

V = RMS voltage, mean line-to-line of three phases

V_R = Nameplate rated voltage

Equation 5-4. Voltage Compensated Amperage Ratio Motor Load Estimation Technique

Both nameplate full-load and no-load current values apply only at the rated motor voltage. Thus, RMS current measurements should always be corrected for over- or under-voltage. If the utilization voltage is below that indicated on the motor nameplate, the measured amperage value is correspondingly higher than expected under rated conditions and must be adjusted downwards. The converse is true if the supply voltage at the motor terminals is above the motor rating. Equation 5-4 shows the relationship of motor load to measured current values.

The Slip Method

As noted earlier, the actual speed of the motor is less than its synchronous speed, with the difference between the synchronous and measured motor operating speed referred to as slip. The amount of slip is proportional to the load imposed on the motor by the driven equipment. Motor rotational speed measurements are generally easy to obtain with a contact tachometer or a strobe light as most motors are constructed so that the shaft is accessible.

The primary reasons to use the slip method to determine motor load are simplicity and safety advantages.[5-1] While the voltage-compensated slip method is attractive for its simplicity, it lacks accuracy. The slip method is generally not recommended for determining motor loads in the field and should be used **only** when motor voltage and operating speed measurements are available.

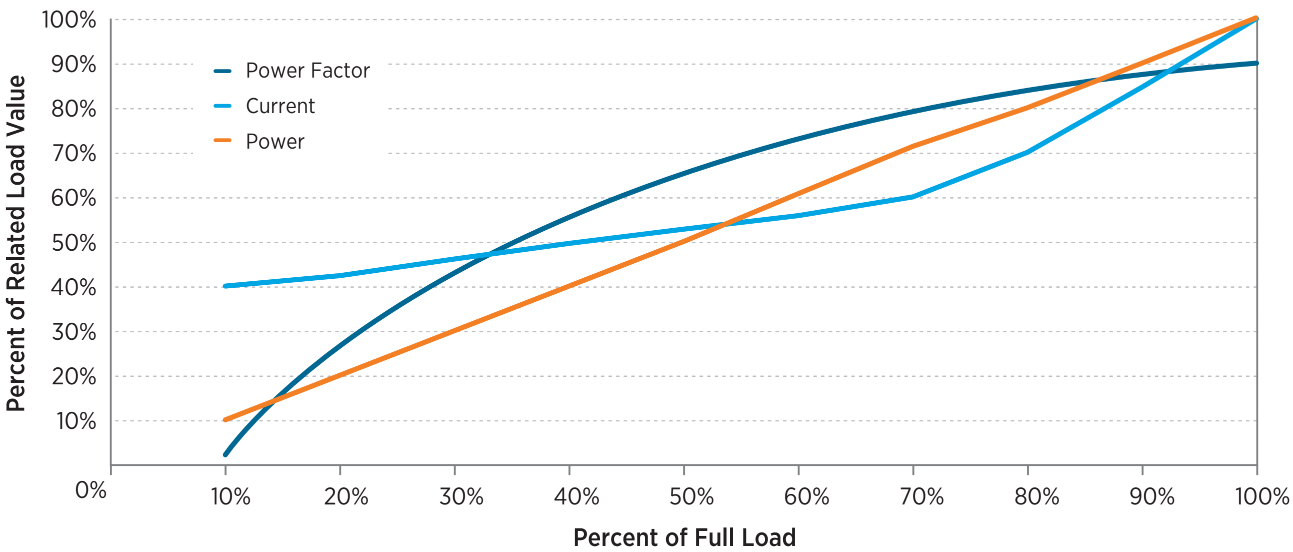

Figure 5-1. Relationships Between Power, Current, Power Factor, and Motor Load. Illustration from EM4MDS

The synchronous speed of an induction motor depends on the frequency of the power supply and on the number of poles for which the motor is wound. The higher the frequency, the faster a motor runs. For a given frequency, the more poles the motor has, the slower it runs. Table 5-1 indicates typical synchronous speeds.

The motor load can be estimated with slip measurements as follows (see Equation 5-5 and Example 5-2).

$$\mathbf{LOAD} = \frac{\mathbf{SLIP}}{(S_S - S_R)} \times 100\%$$

Where:

Load	=	Output power as a % of rated power
Slip	=	Synchronous speed – measured speed in RPM
S_S	=	Synchronous speed in RPM
S_R	=	Nameplate full load speed

Equation 5-5. Slip Motor Load Estimation Technique

Given:

Synchronous speed in RPM	=	1,800
Nameplate full load speed	=	1,750
Measured speed in RPM	=	1,770
Nameplate rated horsepower	=	25 hp

Determine actual output horsepower:

$$\mathbf{LOAD} = \left(\frac{1{,}800 - 1{,}770}{1{,}800 - 1{,}750}\right) \times 100\% = 60\%$$

Actual output horsepower is $\left(\frac{60\%}{100}\right) \times 25\text{ HP} = 15\text{ HP}$

Example 5-2. Using the Slip Technique to Estimate Motor Load

The accuracy of the slip method is limited by multiple factors. The largest uncertainty relates to the 20% tolerance that NEMA allows manufacturers in reporting nameplate full-load speed.[5-1] Given this broad tolerance, manufacturers generally round their reported full-load speed values to some multiple of 5 RPM. Although 5 RPM is a small percentage of the full-load speed and might be considered insignificant, the slip method relies on the difference between full-load nameplate and synchronous speeds.

Table 5-1. Synchronous Speeds (RPM) for Induction Motors

Poles	60 Hz	50 Hz
2	3,600	3,000
4	1,800	1,500
6	1,200	1,000
8	900	750
10	720	600
12	600	500

$$\mathbf{LOAD} = \frac{\mathbf{SLIP}}{\left|(S_S - S_R) \times (V_R / V)^2\right|} \times 100\%$$

Where:

Load	=	Output power as a % of rated power
Slip	=	Synchronous speed – measured speed in RPM
S_S	=	Synchronous speed in RPM
S_R	=	Nameplate full load speed
V	=	RMS voltage, mean line-to-line of three phases
V_R	=	Nameplate rated voltage

Equation 5-6. Voltage Compensated Slip Motor Load Estimation Technique

Given a 40 RPM "correct" slip, a seemingly minor 5 RPM uncertainty results in a 12% change in calculated load.

Slip also varies inversely with respect to the motor terminal voltage squared, and voltage is subject to a separate NEMA tolerance of ±10% at the motor terminals. A voltage correction factor can, of course, be inserted into the slip load equation. The revised slip load can be calculated by using Equation 5-6.[5-2]

An advantage of using the current-based load estimation technique is that NEMA MG1-12.47 allows a tolerance of only 10% when reporting nameplate full-load current. In addition, motor terminal voltages affect current linearly, while slip varies with the square of the voltage.[5-3] While the current ratio technique is superior to the slip method at motor loads above 50%, potential errors are not insignificant. Use input power measurements to determine motor load whenever possible.

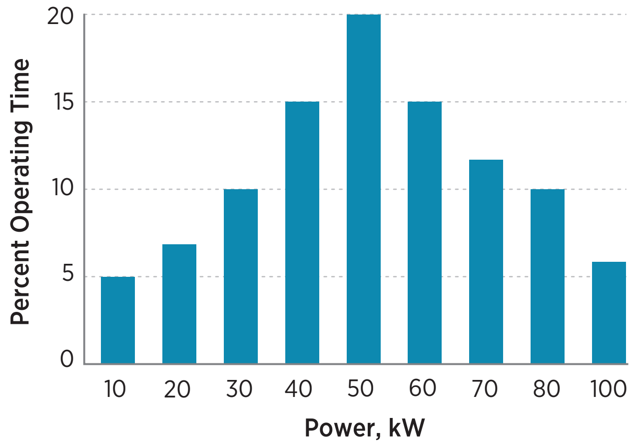

Figure 5-2. Power Logging Data Displayed in Histogram Format

Variable Loads

When the motor load varies over time, you can determine the average load or load profile imposed on the motor. This can be accomplished through long-term monitoring of the input power. If there are two load levels (for instance, a rotary screw compressor with load/unload controls or a water supply pump motor that operates continuously but against two different static heads), the power required at each operating point and the motor load can be determined with a kW meter. Ammeter measurements can then be used to indicate the amount of time spent at each operating point. Determine the weighted average load by timing each motor load period. Characteristics of various load types are given in Table 5-2.[5-3, 5-4] Ammeters are sometimes available on loan from your local utility or from companies operating energy efficiency programs.

When many load levels exist or when loads fluctuate randomly, hand-held instruments provide only a glimpse of the overall load profile. To obtain valid data for variable load applications you must conduct power logging over a period of time. Variable power requirements can be displayed in a histogram bar chart as shown in Figure 5-2. This histogram shows the percentage of time during the power logging period that the motor input power falls

Table 5-2. Characteristics of Motor Loads

Description of Motor Use	Type of Load
Centrifugal Supply Air Fan Motor	Constant, but will change slightly with outside air temperature
Conveyors	Constant or intermittent operation, load will vary based on weight of the items placed on the conveyor
Boiler Feed Water Pump Motor, "On-Off" Control	Starts/stops; constant while on
Hydraulic Power Unit Motor, "On and Bypass" Control	Two levels of different but constant values
Air Compressor Motor with "Inlet Valve" Modulation	Variable Load
Saws and Machine Tools	Variable and random load

within different kW "bins." The load associated with individual kW bin values can be determined through use of the load estimation technique given in Equation 5-3. When load values are substituted for the kW values, the resulting plot indicates the load profile or load-duty cycle for the motor-driven application.

The MotorMaster+ software tool inventory module is designed to accommodate field measurements for in-plant motors with variable loading. The user may specify the percentage of operating time for up to six load "bins." Actual motor loads are automatically determined within the software tool from the measured data entered for each load bin or operating point (The user may enter operating voltage, amperage, power factor, operating speed, or power readings). Both motor load and the efficiency at each load point are determined for the in-service motor. The efficiency values are derived from default part-load efficiency tables that are embedded within the software tool. Default efficiency tables are available for motors of different enclosure types (ODP, TEFC), horsepower ratings, synchronous speeds, and efficiency classes.

MotorMaster+ determines energy savings due to replacing the old in-service motor with a premium efficient motor by superimposing the load-duty cycle for the operating motor onto the replacement premium efficient motor. The efficiency of the premium efficient motor is automatically calculated for each operating load point and aggregate energy savings are determined by summing the calculated savings for each operating bin. This "bin analysis" approach considers the existing motor's load profile, full-load speed, operating hours, and efficiency at each load point to determine the efficiency improvement and operating cost savings given that the incumbent motor is replaced with a specific premium efficient motor. Accurate energy and cost savings results can thus be determined for variable-loaded motors.

Determining Motor Efficiency

Motor loss mechanisms, factors affecting losses, and variations in losses with motor load are discussed in **Chapter 2** of DOE's *Premium Efficiency Motor Selection and Application Guide.* The NEMA definition of energy efficiency is the ratio of a motor's useful mechanical power output to its total electrical power input. This is usually expressed as a percentage, as shown in Equation 5-7.

Motors convert electrical energy to mechanical energy. Motor losses are the difference between the motor input and output power (see Figure 5-3). Once you have determined the motor efficiency and know the input power, you can calculate motor losses and the shaft power delivered to the rotating equipment. By definition, a motor of a given rated horsepower is expected to have the ability to deliver that quantity of power in a mechanical form (brake horsepower) at the motor shaft.[5-5, 5-6]

NEMA Design A and B motors up to 500 hp are required to have a full-load efficiency value stamped on the nameplate (selected from the table of nominal efficiencies, Table 4-1). Many analyses of motor energy efficiency improvement savings assume that the existing motor is operating at its nameplate efficiency. This assumption is reasonable above the 50% load point, because motor efficiencies generally peak at around 75% to 80% load and, for larger motors, performance at 50% load is almost identical to that at full-load. Some larger horsepower motors can exhibit a relatively flat efficiency curve down to 25% of full-load.

It is more difficult to determine the efficiency of a motor that has been in service a long time. It is not uncommon for the nameplate on the motor to be lost or painted over.

$$\eta = \frac{(0.7457 \times HP \times LOAD)}{P}$$

Where:

η = Efficiency as operated in %

HP = Nameplate rated horsepower

Load = Output power as a % of rated power

P = Input power (in kW)

Equation 5-7. Determination of Motor Efficiency

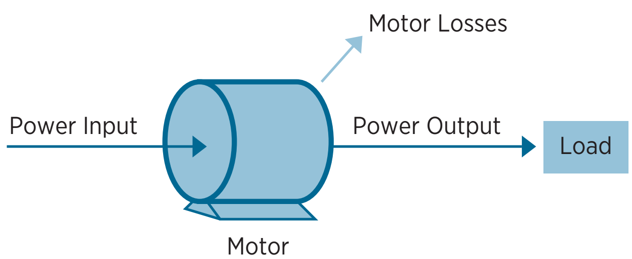

Figure 5-3. Depiction of Motor Losses.

In that case, it is almost impossible to locate efficiency information. Also, there is a possibility that the motor efficiency has been degraded if the motor was rewound prior to the adoption of best practices repair standards.

When nameplate efficiency is missing or unreadable, you must determine the efficiency value at the operating load point for the motor. Record significant nameplate data, if available, and contact the motor manufacturer. With the model, catalog number, type, and serial number, the manufacturer can identify approximately when the motor was manufactured. Often, the manufacturer will have historical records and can supply nominal efficiency values as a function of load for a family of motors.[5-5, 5-6] Prior to 1980, reported motor efficiencies might have been "catalog" versus tested efficiency values.

If the manufacturer cannot provide motor efficiency values, you may use estimates from Appendix B, which contains nominal efficiency values at full, 75%, 50%, and 25% load for typical standard efficiency motors of various sizes and with synchronous speeds of 3,600, 1,800, 1,200, and 900 RPM. Appendix B is derived from the MotorMaster+ database and indicates "industry average" full- and part-load performance values for older (pre-1997 vintage) standard efficiency motors.

Three steps are used to determine motor load and efficiency. First, use power, amperage, or slip measurements to estimate the load imposed on the operating motor. Second, obtain a motor part-load efficiency value consistent with the approximated load either from the manufacturer or by interpolating from the data supplied in Appendix B. Finally, derive your final load estimate using both the power measurement at the motor terminals and the part-load efficiency value, as shown in Equation 5-8. This approach yields load and efficiency values that are consistent with the input power measurements. Of course, the easiest way to determine motor load and efficiency at its load point is to enter the motor nameplate information and field measurements into the MotorMaster+ software tool.

Motor efficiency should not change with age or by a motor's repair history when repair "best practices" are followed. A study conducted by EASA and the Association of Electrical and Mechanical Trades (AEMT) shows that, when best practices are followed to repair or rewind motors, they can maintain their original efficiency, within the range of accuracy for the efficiency test method. In several instances, efficiency of the repaired motor slightly improved.[5-7]

$$\text{LOAD} = \left| \frac{P \times \eta}{HP \times 0.7457} \right|$$

Where:

Load = Output power as a % of rated power

P = Three phase input power in kW

η = Efficiency as operated in %

HP = Nameplate rated horsepower

Equation 5-8. Determination of Motor Load

Motor Load and Efficiency Estimation Techniques

Oak Ridge National Laboratory developed the Oak Ridge Motor Efficiency and Load (ORMEL), a computer program that uses an equivalent-circuit method to estimate the load and efficiency of an in-service motor. Only nameplate data and a measurement of rotor speed are required to compute both the motor efficiency and load factor. Dynamometer tests have shown that the method produces efficiency estimates that average within ±3 percentage points of actual. This level of accuracy holds for motor loads ranging from 25% to 100% of rated capacity.[5-8] The program allows the user to enter optional measured data, such as stator resistance, to improve the accuracy of the load and efficiency estimates. The ORMEL load estimation algorithms are embedded in and available with the MotorMaster+ software tool.

Motor efficiency estimation methods and devices were evaluated at the Motor Systems Resource Facility at Oregon State University.[5-9] Efficiencies calculated by three motor analyzers and several algorithms and computer programs were compared with dynamometer-determined efficiencies on five motors under numerous operating conditions. Motor analyzer errors were less than 3% for all motors and less than 1% for newer motors in good condition on a balanced power supply. (Unfortunately, power supplies are not always balanced in industrial settings). The motor analyzers also were evaluated in the field, but they were not embraced because the need to uncouple motors from the driven equipment disrupted production.

Performing a no-load test is also labor intensive. The analytical methods avoid the need to purchase an expensive motor analyzer, but still require a power meter with good accuracy at a very low power factor.

Manufacturers of motor current-signature predictive maintenance analyzers have introduced products that advertise their capability for determining efficiency without the need for uncoupling motors from their driven equipment. Connecting through existing potential transducers and current transducers also allows testing on medium voltage motors. These devices also were evaluated at Oregon State's Motor Systems Resource Facility. The evaluation examined accuracy, lack of intrusion, and ease of use. Both analyzers tested exhibited efficiency errors generally under 2% at high and intermediate motor loading.[5-10, 5-11] Errors or uncertainties of this magnitude make it difficult to reliably evaluate potential energy savings due to replacement of an older standard efficiency motor with a new premium efficiency model.

Sophisticated electronic equipment is now available to measure efficiency of motors while they remain connected to their driven equipment. These new efficiency testers are accurate to within 0.5% of the readings one would obtain in a laboratory with a dynamometer.

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CHAPTER 6

ANALYZING MOTOR EFFICIENCY OPPORTUNITIES

This chapter illustrates how to use field measurements to determine demand reductions, energy savings, and the simple payback on investment in a new or replacement premium efficiency motor.

Calculating Annual Energy and Demand Savings

To determine the annual cost savings from the purchase of a premium efficiency motor, first you need to determine the annual energy consumption and demand savings. Premium efficiency motors require fewer input kilowatts to provide the same horsepower output as a standard efficiency motor. The difference in efficiency between the premium efficiency motor and a comparable standard efficient motor determines the demand or kW reduction. For two similar motors operating at the same load but having different efficiencies, you can use Equation 6-1 to calculate the reduction in input kilowatts.[6-1] With the reduction in input power known, annual energy savings can be calculated as shown in Equation 6-2.

Equations 6-1 and 6-2 apply to motors operating at a specified constant load. For varying loads, you can apply the energy savings equation to each portion of the duty cycle where the load is relatively constant for an appreciable period of time. Total energy savings are then the sum of the savings for each load period. The equations are not applicable to motors operating with pulsating loads or to loads that cycle at rapid intervals.

You can use demand savings and annual energy savings, along with utility rate schedule information, to estimate your annual reduction in operating costs. This general calculation of total annual cost savings is shown in Equation

$$kW_{SAVED} = HP \times [\,LOAD\%/100\,] \times 0.7457 \times \left(\frac{100}{\eta_{STD}} - \frac{100}{\eta_{PREM}}\right)$$

Where:

kW_{SAVED}	=	Savings from efficiency improvement in kW
hp	=	Nameplate rated horsepower
Load	=	Output power as a % of rated power
η_{STD}	=	Efficiency of a standard motor as operated in %
η_{PREM}	=	Efficiency of premium efficiency motor as operated in %

Equation 6-1. Determining the Reduction in Electrical Demand due to Replacing a Standard Efficiency with a Premium Efficiency Motor

$$kWh_{SAVINGS} = kW_{REDUCTION} \times HOURS$$

Where:

$kWh_{SAVINGS}$	=	Annual electric energy saved in kWh
kW_{SAVED}	=	Savings from efficiency improvements in kW
Hours	=	Annual operating hours

Equation 6-2. Determination of Annual Energy Savings

$$SAVINGS = (kW_{SAVED} \times 12 \times RATE_D) + (kWh_{SAVINGS} \times RATE_E)$$

Where:

Savings	=	Total annual dollar savings
kW_{SAVED}	=	Savings from efficiency improvements in kW
$Rate_D$	=	Monthly demand charge in $/kW/mo
$kWh_{SAVINGS}$	=	Annual electric energy saved in kWh
$Rate_E$	=	Tailblock energy charge in dollars per kWh

Equation 6-3. Calculation of Total Annual Cost Savings

6-3. Apply seasonal demand charges appropriately and always examine declining block rate schedules to ensure that savings are based on marginal energy costs.

Assessing Economic Feasibility

Because of better design and low-loss/high-quality materials, premium efficiency motors typically cost 15% to 30% more than their energy efficient counterparts. In many situations (e.g., new motor purchases, repairs, or motor replacement) you quickly recover this price premium through energy cost savings. To determine economic feasibility, examine the total annual energy savings in relation to the full or incremental cost of purchasing and installing the premium efficiency motor. See Appendix C for a motor energy savings calculation form.

Most industrial plant managers base their energy efficient equipment purchase decisions on a simple payback analysis, and they require that investments be recovered through energy savings within 1 to 3 years. The simple payback is defined as the period of time required for the savings from an investment to equal the initial or incremental cost of the investment. For initial motor purchases or replacement of burned-out and non-rewindable motors, the simple payback period for the investment in a new premium efficiency motor is the incremental cost for the premium efficiency motor (less any available utility rebate) divided by the total annual cost savings. No installation costs are assessed as either the premium efficiency or energy efficient motor must be installed. This calculation is shown in Equation 6-4.

For the motor repair/replace decision, the simple payback is the total cost of the new premium efficient motor minus the repair cost and any utility incentive (if available), divided by the total annual electrical energy and demand reduction cost savings. Motor removal and installation costs are not considered as the failed motor must be removed and a replacement spare or premium efficient motor installed.

For replacement of in-service or operating motors, the simple payback is the ratio of the full cost of purchasing and installing a new premium efficiency motor relative to the value of the total annual electrical savings. Base or "bare" motor installation costs must include an overhead and profit multiplier when outside contractors are used. A labor cost adjustment should be applied to motors with restricted access or special handling requirements. The simple payback given replacement of an operable motor is given in Equation 6-5.

$$\mathbf{SPB} = \frac{\mathbf{\Delta\ COST - REBATE}}{\mathbf{SAVINGS}}$$

Where:

SPB	=	Simple payback in years
Δ Cost	=	Price premium for premium motor compared to an energy efficient motor
Rebate	=	Utility rebate for premium efficient motor
Savings	=	Total annual dollar savings

Equation 6-4. Simple Payback for the New Motor Purchase Scenario

$$\mathbf{SPB} = \frac{\mathbf{(COST + COST_{INST} - REBATE)}}{\mathbf{SAVINGS}}$$

Where:

SPB	=	Simple payback in years
Cost	=	New motor cost
$\text{Cost}_{\text{INST}}$	=	Installation cost
Rebate	=	Utility rebate for premium efficiency motor
Savings	=	Total annual cost savings

Equation 6-5. Simple Payback for the Replacement of an Operable Motor

The following analysis for purchasing a *new* 250-hp TEFC motor operating at 75% of full rated load illustrates how to use Equations 6-1 through 6-4. The analysis determines the cost effectiveness of purchasing a new premium efficiency motor having a 3/4-load efficiency of 96.2% (η_{PREM} = 96.2) instead of an energy efficient motor (η_{EE} = 95.5%). The motor is expected to be in operation for 8,000 hours per year. Electrical energy is purchased at a rate of $0.08/kWh with a demand charge of $8.00/kW/month.

Kilowatts saved (from Equation 6-1):

$$kW_{REDUCTION} = 250 \times 0.75 \times 0.7457 \times (100/95.5 - 100/96.2) = 1.06 \text{ kW}$$

This is the amount of power conserved by the premium efficiency motor during each hour of use. Multiply this by the number of operating hours at the indicated load to obtain annual energy savings.

Energy saved (from Equation 6-2):

$$kWh_{SAVINGS} = 1.06 \times 8{,}000 = 8{,}480 \text{ kWh/year}$$

Assuming utility energy and demand charges of $0.08/kWh and $8.00/kW/month (from Equation 6-3):

$$\text{Cost Savings} = (1.06 \text{ kW} \times 12 \text{ mo} \times \$8.00/\text{kW-mo}) + (8{,}480 \text{ kWh/year} \times \$0.08/\text{kWh}) = \$780/\text{year}$$

In this example, installing a premium efficient motor reduces the utility bill by $780 per year. The simple payback for the incremental cost associated with a premium efficiency motor purchase is the ratio of the price premium or incremental cost to total annual cost savings. Generally, premium efficiency motors might cost up to 15% to 30% more than a motor of an energy efficient design.

Assuming a price premium of $2,500 and no utility incentive, the simple payback on investment is as follows (from Equation 6-4):

$$\text{SPB} = (\$2{,}500 - 0) / \$780 = 3.2 \text{ years}$$

The additional investment required to purchase a premium efficiency motor is recovered within 3.2 years. Premium efficiency motors often pay for themselves rapidly through reduced energy consumption and operating costs. After this initial payback period, annual savings will continue to be reflected in lower operating costs, and they will add to a company's total profits.

Although the energy and cost savings associated with purchasing a premium efficiency motor can be impressive in many applications, selecting the premium efficiency unit is not always cost effective. Motors that are lightly loaded or infrequently used—such as motors driving control valves—may not consume enough electricity to allow the premium efficiency model to produce significant energy and cost savings. Remember, for a motor operating under a constant load, the electricity savings associated with an efficiency improvement are directly proportional to annual hours of operation. Special and definite purpose motors may carry a substantial price premium or may not be available in premium efficiency models.

Example 6-1

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CHAPTER 7

MOTOR EFFICIENCY IMPROVEMENT PLANNING

An industrial facility should adopt a new motor purchase policy and plan ahead in order to implement energy efficiency measures when opportunities arise. Take the following planning steps for each motor in the plant that meets the minimum size requirements:

- Make field measurements necessary to determine actual motor loads.
- Establish the existing motor efficiency at its load point.
- Determine annual operating hours.
- Contact your utility account representative to determine if the utility offers a premium efficient motor rebate or has other energy efficiency incentive programs.
- Identify in-service standard efficiency motors that are cost-effective candidates for immediate replacement with a new premium efficient motor.
- Improve plant reliability and productivity through replacement of “problem” motors, i.e., those with a history of frequent or repeated failures. Conduct failure analyses to determine the root cause of the failure, correct system issues, and replace these motors with motor designs better suited for the application. Without correcting the root cause of the failures, the reason for the continued failures may be passed along to the new premium efficient motor.
- Consider replacing motors that are less than 50% loaded with a downsized premium efficiency motor and a frame adapter.
- Consider the immediate replacement of older (pre-1964) U-frame motors with new premium efficiency T-frame motors.
- Conduct a repair/replace analysis to determine the cost-effectiveness of purchasing and installing new premium efficient motors versus rewinding or overhauling failed standard efficiency motors.
- Establish a premium efficiency motor-ready spares inventory.

MotorMaster+ Motor Energy Management Software

DOE has supported the development of MotorMaster+, a premium efficient motor selection and energy-management software tool.

MotorMaster+ software supports industrial energy management activities by providing the following:

- The ability to select the “best” available new or replacement motors using an internal database of price and performance information for more than 20,000 motors rated from 1 to 2,000 hp
- An in-plant motor inventory module in which motor nameplate data, operating hours and application information, and field measurements are linked to utility, facility, and process information
- The ability to automatically estimate in-service motor load and efficiency when field measurements are available
- The ability to scan for motors that operate under abnormal or sub-optimum power supply conditions
- Descriptor search capability to assist you in targeting energy-intensive equipment and replacing inefficient motors
- Inventory management functions, including maintenance logging and spares tracking
- Analysis features for rapidly determining the annual energy, demand, and dollar savings resulting from selecting and using a premium efficient motor in a new purchase or retrofit application
- The ability to conduct energy savings analyses for “batches” or selected populations of operating motors
- Energy accounting features, including summary reports on utility billing, plant production, energy efficiency measures installed, energy and dollar savings, and greenhouse gas emissions reductions
- Life-cycle costing capability, including the ability to compute the after-tax return on investment in energy efficiency measures.

In addition to MotorMaster+, the MotorMaster International software tool contains performance data for the 50 Hz IEC or metric motors in widespread use outside North America. It has all of MotorMaster+’s motor selection capabilities, including life-cycle costing. Both MotorMaster+ and MotorMaster International can be obtained at the AMO’s Energy Resource Center *(www.eere.energy.gov/manufacturing/tech_assistance/ecenter.html)*.

- Consider the accelerated replacement of in-service standard efficiency motors.
- Prepare an action plan. Mark or tag motors so that the appropriate repair/replace action is taken at the time of motor failure.

Establish a New Motor Purchase Policy

EISA imposes mandatory minimum full-load efficiency standards for most general purpose motors in the 1- to 200-hp size range (see **Chapter 4** for additional information). The result is that motors sold in or imported into the United States must already meet or exceed the premium efficiency motor performance standards. This requirement extends to foot-mounted motors with speeds of 3,600, 1,800, and 1,200 RPM and with ODP, TEFC, and explosion-proof enclosures.

EISA requires that general purpose motors with ratings between 201 and 500 hp must have a full-load efficiency that meets or exceeds the NEMA energy efficient motor standards. In addition, 1- to 200-hp U-frame, Design C, close-coupled pump, footless (C-face and D-flange), 900 RPM, vertical shaft normal-thrust, fire pump, and motors designed to operate on utilization voltages of 200 V and 575 V must also meet or exceed the energy efficient motor standards. While premium efficiency motors are available in most of these ratings, purchasing them is voluntary.

Consider a motor purchase policy that requires all new low and medium voltage motors in the 1- to 500-hp size range meet the NEMA premium efficiency motor standards. Premium efficiency motors would be specified when ordering equipment from OEMs or for all imported equipment or process trains.

In-Service Motor Energy Efficiency Opportunities

An immediate motor replacement should be scheduled when your analysis indicates that replacing an operating motor with a premium efficiency model yields a simple payback period that meets your company investment criteria. Most of the time, the "triggering event" for an energy decision occurs when an operating motor fails and must be replaced. By planning ahead, you can develop an action plan and treat the motor failure as an opportunity to improve energy efficiency within your plant.

There are two basic scenarios that must be investigated. One assumes the failure of an operating motor; the second assumes there has been no motor failure. Each event calls for a different type of analysis. In each scenario, there are a number of alternatives to consider and analyze. The situations and alternatives are as follows:

- **The In-Service Motor Fails**
  - Repair the motor.
  - Replace the motor with a new energy efficient motor (in ratings where they can still be sold).
  - Replace the failed motor with a new premium efficiency motor.
- **The In-Service Motor Does Not Fail**
  - Allow the motor to continue operating as is.
  - Replace the motor immediately with a premium efficiency model.

In either situation, the alternatives can include downsizing if the existing motor is oversized and underloaded.

When an Operating Motor Fails

When a motor fails, there are two options: repair the motor or replace it with a new one.

Repair the Motor

For larger motors, the least expensive approach in terms of capital costs is to repair the failed motor. Repair sometimes means rewinding the stator in addition to making mechanical repairs and replacing bearings. The motor will, of course, be out of service during repairs. To justify a major rebuild, the original stator and rotor must be in serviceable or reasonably repairable condition. Repair of significant rotor or stator core damage usually is cost effective only on larger motors.

It is not unusual to find industries paying more to repair smaller general purpose standard efficiency motors than they would pay to purchase a new premium efficiency motor. Figure 7-1—prepared from actual cost quotations—shows that the repair cost (rewind plus bearing replacement) for motors 25 hp and below is about the same as the cost of a new premium efficiency severe duty motor. Taking into account its list price discount for the purchase of new premium efficiency motors, for this industrial facility, 1,800 RPM general purpose motors 25 hp and below should ***always*** be replaced when they require rewinding, regardless of their annual operating hours. Note that not all repairs require a motor rewind.

Studies indicate that bearing failures account for approximately two-thirds of all motor failures with winding failures accounting for one-fifth of all failures.[7-1]

Even if a small operating premium efficiency motor were to fail, if it was not under warranty, it should be replaced with another premium efficiency motor instead of being repaired. Only repair the smaller special or definite purpose motors that have a significant price premium or are not available in a reasonable time frame. Premium efficiency motors generally cost about 15% to 30% more than standard efficiency motors.

Some industries determine a "horsepower breakpoint" that is used to establish and simplify their motor replacement policy. Motors larger than the breakpoint horsepower rating are typically rewound and returned to service when they fail; motors smaller than the breakpoint horsepower rating are recycled and replaced with new premium efficiency motors. Many process industries have established a horsepower breakpoint based upon cost-effectiveness at 50 hp.

The breakpoint horsepower for your plant is dependent on rewind costs, the list price discount your distributor applies to new premium efficiency motor purchases, utility rates and incentives, and annual operating hours for your motors. Appendix D contains a blank Motor Repair versus Replace Breakpoint worksheet. A completed worksheet provides the annual energy savings and simple payback periods from replacing failed standard efficiency motors of various horsepower ratings with premium efficiency models. The simple payback lengthens as the horsepower rating increases. Scroll down to the highest horsepower rating where your simple payback criteria are satisfied. This is the horsepower breakpoint for your plant. A tool for determining the horsepower breakpoint is available on the Advanced Energy website *(www.advancedenergy.org/portal/hp_breakpoint_tool/)*.

Industries typically cite simple paybacks in the range of 1 to 3 years for an energy efficiency project to be deemed as cost-effective. Reasons for lengthening the normal acceptable simple payback criteria for premium efficiency motor replacements include the secondary benefits associated with increasing both motor efficiency and durability—particularly when the replacement motor is of severe-duty or IEEE 841 design. While difficult to quantify, these secondary benefits occur due to the superior performance of the new premium efficiency motor in contrast to the performance of the rewound standard efficiency motor. The secondary benefits may include improved motor reliability and extended time between motor failures, warranty coverage if a motor does suffer an unexpected failure, and the potential for increased plant up-time accompanied by an increase in production.

Replace the Failed Motor with a New Premium Efficiency Model

When replacement is needed, it is often cost effective to purchase a new premium efficient motor. Exceptions can include when an energy efficient motor is in the spares

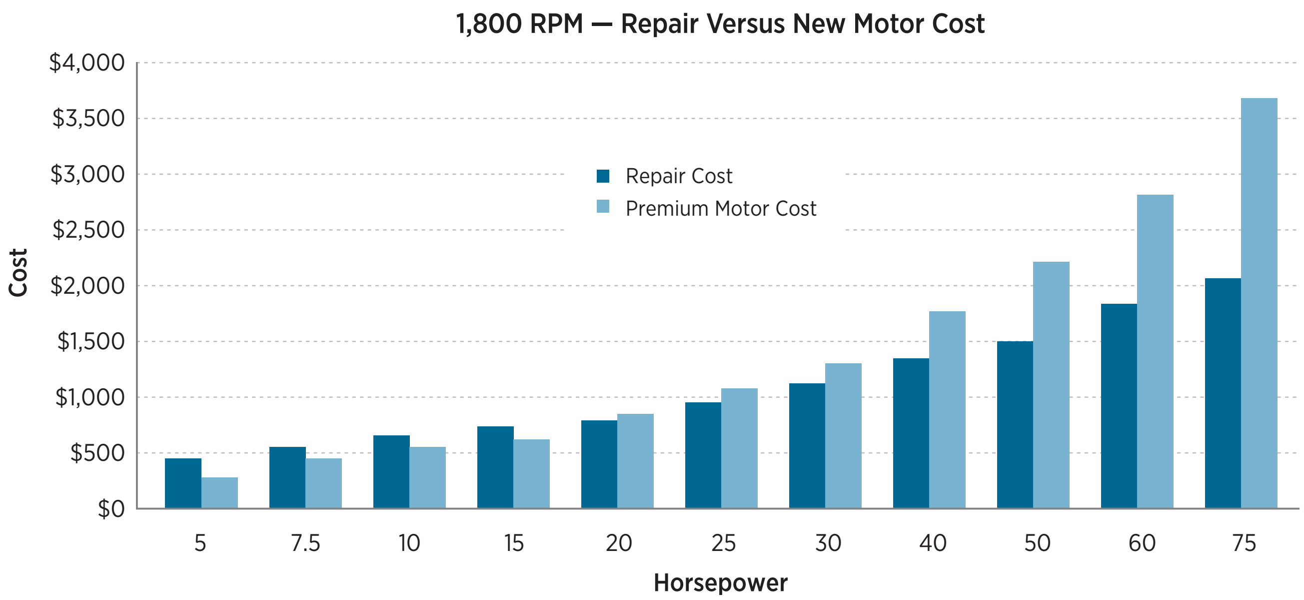

Figure 7-1. Repair and New Premium Efficiency Motor Costs (for 1,800 RPM TEFC Motors, 2011 Prices)

Table 7-1. Motor Rewind Versus Replacement Analysis (100 hp, 1,800 RPM, TEFC Motor)

	Repaired Standard Efficiency Motor	New Premium Efficiency Motor
Motor Rating (hp)	100	100
Load, %	75	75
Efficiency at Load Point, %	92.2	95.3
Motor Rewind Loss, %	0.5[1]	---
Annual Operating Hours	6,000	6,000
Cost (Rewind/Purchase)	$2,590	$5,940[2]
Motor Rebate		(None)
Annual Energy Use, kWh	366,002	352,256
Annual Energy Cost, $	$29,280	$28,180
Demand Charge, ($/year)	$5,856	$5,636
Savings Compared to Repair		
Energy (kWh/year)		13,746
Energy Value ($/year)		$1,100
Demand Reduction (kW)		2.3
Demand Savings ($/year)		$220
Total Savings ($/year)		$1320
Simple Payback (years)		2.5

[1] If repair best practices are followed, no efficiency loss reduction should be expected.

[2] Assumes a 50% list price discount.

inventory or annual operating hours that are very low, or both. When a previously rewound standard efficient motor fails, however, it should always be considered for replacement with a premium efficient motor.

The economic analysis for deciding whether to repair or replace a failed motor is straightforward. The "do nothing" alternative doesn't apply. The least-capital-cost alternative, overhauling (bearing replacement plus clean, dip, and bake) or rewinding and installing new bearings on the failed motor becomes the base case. The biggest challenge is estimating the cost of the repair and the motor's efficiency after repair. MotorMaster+ can be of help as it provides default motor repair costs (rewind plus bearings) plus default losses that might be incurred during the motor repair process if repair best practices are not followed.

Start your analysis by identifying the operating cost of each alternative action. It is then possible to compare both the incremental cost of the alternative and the operating cost reduction associated with it. Energy consumed in motor losses is given in terms of kWh. Differences in operating costs are easy to compute using information from the utility rate schedule. Always use marginal or incremental energy and capacity costs.

Results of a MotorMaster+ "repair versus replace" analysis are summarized in Table 7-1. Comparative performance values are based on an energy cost of $0.08/kWh and a monthly demand charge of $8.00/kW/month. You can also calculate these values with the equations provided in **Chapter 6**. Absent utility incentives, the analysis indicates a 2.5 year simple payback on the investment in a premium efficiency replacement motor. The failed motor could be rewound and retained as a spare, recycled, or sold for its salvage value.

The MotorMaster+ compare module allows for a side-by-side comparison of motors with different horsepower ratings. It can even adjust the output power for part-load operating speed differences for motor-driven "affinity law" loads (e.g., centrifugal pumps or fans).

You will have to weigh several factors to make a good repair versus replace decision:

- Cost of the replacement premium efficiency motor
- Efficiency of proposed premium efficiency motor
- Downtime cost for each alternative (if different)
- Cost to overhaul or rewind the existing motor
- Efficiency of the existing motor after repair
- Availability of a utility rebate.

Helpful Tip

For more information on the repair process, see the 2003 EASA/AEMT Rewind Study[7-4] *The Effect of Repair/Rewinding on Motor Efficiency* and DOE's *Model Repair Specifications for Low Voltage Induction Motors* available at the AMO's Energy Resource Center *(www.eere.energy.gov/manufacturing/tech_assistance/ecenter.html)*.

Information on premium efficiency motor costs and efficiency at various load points is available from MotorMaster+, the motor manufacturer, or your local motor distributor. Downtime costs are often the same for each alternative. In general, large or special-purpose motors can be repaired more quickly than they can be replaced, but distributors usually have premium efficiency general purpose motors in stock or can quickly obtain them from a motor manufacturer's regional warehouse.

The motor comparison window of MotorMaster+ provides a default cost for repair (rewind plus new bearings) for your existing motor, but it can be overwritten. In fact, it usually needs to be overwritten, because motor repair costs vary too much for users to rely on the default number for investment decisions. Repair costs vary with the extent of damage, geographical location, overtime requirements, and type of stator impregnation. Moreover, repairs are usually done by companies or shops rather than by manufacturers, so there is no annual update of repair costs in the MotorMaster+ database. You can obtain better information on repair costs in one of two ways. You can maintain your own cost database using records of recent repairs or request a price list from your local service center. Alternatively, you can subscribe to a motor repair cost guide that is updated annually. A widely used price estimator is available from Vaughens' Price Publishing Company.[7-2]

Motor rewind losses may range from a 0.50% to 1% efficiency reduction for 40 hp or smaller motors and 0.25% to 0.50% for motors over 40 hp if repair best practices are not followed.[7-4] If good repair practices are followed, no reduction in efficiency should be expected. Require that your service center adheres to the repair practices recommended in ANSI/EASA Standard AR100-2010.[7-3] Large industries maintain staff that regularly audit their motor service centers. Look for evidence of a quality management program such as Proven Efficiency Verification *(www.advancedenergy.org/programs/proven-efficiency-verification-for-motor-repair)*, the Green Motors Practices Group *(www.greenmotors.org/gmi.htm)*, ISO 9000, or EASA-Q.

When an Existing Motor Does Not Fail

If the monitor continues to function, the energy manager has two options: let the motor operate as usual or replace it with a new premium efficiency one.

Let the Motor Continue to Operate As Is

There are many demands on an energy manager's time; thus, reducing motor losses may not be a high priority in comparison to other important duties. In addition, there are no immediate costs associated with keeping a working standard efficiency motor operating. Savings may simply accrue too slowly to justify the investment in a new premium efficiency motor. Each plant is different, so decisions concerning the relative importance of projects are best left to those responsible for operating the plant.

Replace Operating Motor with a New Premium Efficiency Motor

A premium efficiency replacement motor can often be found in the same frame size as an existing standard efficiency T-frame motor, and with comparable starting torque and locked-rotor current. Frame adapters or conversion bases are necessary for pre-1952 motors, U-frame motors, and special designs. The average premium efficiency motor rotates at a fraction of a percent higher speed than its standard efficiency counterpart. In many centrifugal pump and fan applications, this will increase flow and energy consumption, which can offset or diminish the expected energy savings. Full-load speeds do vary among premium efficiency motors, and a model can often be found to closely match the speed of all but the slowest standard efficiency motors. You can change sheave or pulley sizes with belt-driven loads so the rotating equipment operates at its original or required speed. An increase in replacement motor full-load speed is not of importance when the motor is controlled by a variable speed drive.

Table 7-2 illustrates the benefits of replacing an existing in-service standard efficiency motor with a premium efficiency model (again, new motor price and performance information comes from MotorMaster+). Comparative performance values are based on an energy cost of $0.08/kWh and a monthly demand charge of $8/kW/month.

Replacing an operating motor is usually not cost effective. The 5.1-year simple payback in the example shown in Table 7-2 is much longer than the simple payback acceptable to most industrial plant managers. Payback, however, is very sensitive to individual circumstances. An operating time of 8,000 hours or availability of a utility rebate would reduce the simple payback period, and higher electrical energy and demand costs would reduce it even further.

Other factors besides cost can contribute to the decision to replace a working motor. For example, you might be nearing a scheduled downtime for a process line, and age or predictive maintenance trends may indicate trouble from an existing motor. It usually is wise to replace a motor before it fails rather than risk an unscheduled process-line shutdown.

Table 7-2. Operating Motor Replacement Analysis (75 hp, 1,800 RPM, TEFC Motor)

	Original Standard Efficiency Motor	New Premium Efficiency Motor
Motor Rating (hp)	75	75
Load, %	75	75
Efficiency at Load Point, %	92.0	95.5
Annual Operating Hours	6,000	6,000
Motor Cost		$4,640[1]
Installation Cost		$330
Annual Energy Use, kWh	273,751	263,639
Annual Energy Cost, $	$21,900	$21,091
Demand Charge, ($/year)	$4,380	$4,218
Annual Energy Savings (kWh/year)		10,112
Energy Savings ($/year)		$809
Demand Reduction (kW)		1.7
Demand Savings ($/year)		$162
Total Savings ($/year)		$971
Simple Payback (years)		5.1

[1]Assumes a 50% list price discount.

Motor Downsizing

Motor-driven systems are often designed for "worst case" operating conditions. Safety margins are then applied, and the motor is then sized up to the next rating.[7-5] As a result, in-service motors are often oversized and underloaded.

The power that a motor delivers is determined by the interaction between the motor and the load. An AC motor turns at a speed determined by the power supply frequency and its design (i.e., the number of magnetic poles). The motor determines the speed at which the load will run. Any load (e.g., a pump, fan, or conveyor) has a characteristic torque requirement; that is, for any running speed, it resists with a certain torque. This relationship is illustrated by a torque-speed curve. When the motor and the load are coupled, the motor dictates the running speed and the load dictates the torque requirements.

Power delivered by the motor is proportional to speed times torque (hp = torque × speed/5,252 when torque is in foot-pounds and speed in RPM). The load is oblivious to the rated power output of a motor—the load just requires the torque commensurate with its driven speed. Suppose a partially-loaded 1,800 RPM 100-hp motor delivers 50 shaft hp to its driven equipment. If it is replaced by an 1,800 RPM 50-hp motor, the motor will still deliver only 50 hp to the load. The replacement motor is now operating at 100% load and at its full-load speed and full-load efficiency.

Quick Fact

Slip and operating speed are dependent upon applied load. A motor begins to rotate slower as loads on it are progressively increased. At the full-load point, operation occurs at the full-load speed. Oversized and lightly loaded motors tend to operate closer to their synchronous speed. A downsized or fully-loaded premium efficiency motor, with a higher full-load RPM than the motor to be replaced, may actually operate at a slower speed than the original oversized motor. This speed shift can be significant for centrifugal loads and must be taken into account when computing both energy savings and electrical demand reductions.

Downsizing can be a money-saver for two reasons:

- When purchasing replacement motors, smaller motors tend to cost less.
- An under-loaded motor operates less efficiently and with lower power factor than a motor loaded at 75% to 100% of rated power.

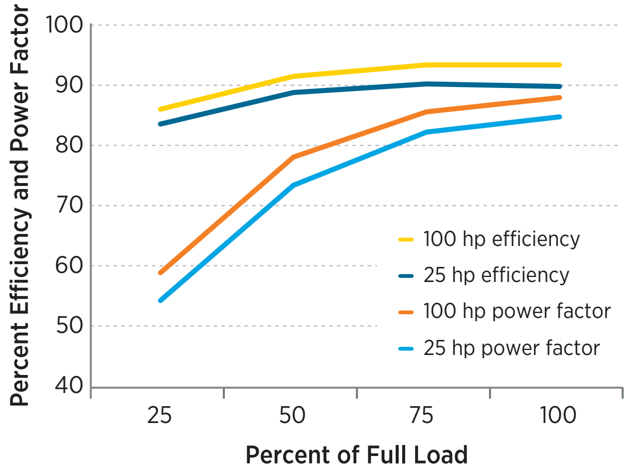

Figure 7-2. Motor Performance at Part-Load.
Illustration from EM4MDS

Motor efficiency curves vary by horsepower rating and synchronous speed, but most peak near 75% load and still provide near-nameplate efficiency at half-load. Below half-load, efficiency begins to drop off dramatically. Performance curves for two typical motors are presented in Figure 7-2. When determining energy savings due to replacing an in-service motor with a downsized model, you must determine the appropriate part-load efficiency for each motor. Since larger motors exhibit a higher efficiency over their load range, it is possible to find that the larger standard efficiency motor's half-load efficiency is comparable to or greater than the full-load efficiency of a premium efficiency replacement motor rated at half the power output.[7-6]

Table 7-3 summarizes the energy savings from replacing an in-service 40%-loaded 100-hp motor with downsized standard and premium efficiency motors of different horsepower ratings. The table shows the efficiency at the load point given that motors of different horsepower ratings and efficiency classes are used to satisfy the fixed 40-hp load. The analysis takes into account the motor efficiency at the load point and indicates the input power requirements (kW) for all of the replacement motor choices.

When the 100-hp standard efficiency motor is replaced with a 40-hp standard efficiency motor, the result is only a 0.37 kW reduction in input power (33.45 kW – 33.08 kW).

Table 7-3. Motor Downsizing Versus Efficiency Class of Replacement Motor. Source: WSU Motor Training Materials

Motor Rating, hp	Motor Oversizing 40% Load on a 100 Horsepower Motor			
	Standard Efficiency		Premium Efficiency	
	Efficiency at Load Point, %	Input kW	Efficiency at Load Point, %	Input kW
100	89.2	33.45	93.7	31.84
75	91.1	32.75	95.1	31.37
60	91.5	32.60	94.9	31.44
50	91.6	32.57	94.8	31.47
40	90.2	33.08	94.2	31.67

If the in-service standard efficiency motor is replaced by either a 100-hp or 40-hp premium efficiency motor, Table 7-3 indicates reductions in input power of 1.61 and 1.78 kW, respectively. Replacing an oversized standard efficiency motor with a downsized standard efficiency motor results in negligible energy savings. Energy savings are greatly increased when the oversized standard efficiency motor is replaced with a premium efficiency motor of either the same or a downsized hp rating.

The first step in considering downsizing is to determine the loading on the existing motor, using the methods discussed in **Chapter 5**. Don't downsize motors that have to start high inertia loads. As a rule of thumb, it is best not to downsize to the point where the replacement motor is more than 80% loaded. You can exceed this rule when you are certain of the maximum motor loading. Remember that downsizing requires an adapter plate to compensate for the difference in mounting bolt hole locations and shaft height. A new coupling might also be required. Overcurrent protection must also be modified when a downsized motor is installed.

The decision to change out and perhaps downsize an operating motor is also influenced by one or more of the following:

- Estimated remaining service life for operating motor
- Annual hours of operation
- Availability of a smaller premium efficiency motor in company inventory
- Utility rates plus existing efficiency incentives or motor rebates
- The energy manager's ability to analyze the situation and propose an economically sound change.

Table 7-4. Typical U-Frame to T-Frame Transition Base Prices (2011)

Horsepower Rating	Synchronous Speed	U-Frame Size	Transition Base Cost
125	1,800	445U	$261
125	1,200	445U	$261
50	1,800	365U	$153
50	1,200	405U	$203
30	1,800	326U	$121
30	1,200	365U	$153
25	1,800	324U	$121
25	1,200	364U	$153
10	1,800	256U	$65
10	1,200	284U	$92
7.5	1,800	254U	$65
7.5	1,200	256U	$65

Helpful Tip

If the old U-frame motors are not immediately replaced with premium efficient T-frame motors, purchase and maintain an inventory of U- to T-frame adapters or conversion bases. Without ready access to a conversion base, an old standard efficiency U-frame motor from the spares inventory is likely to be installed with the failed U-frame motor rewound and placed into the spares inventory.

Upgrade Old U-Frame to Premium Efficiency T-Frame Motors

Consider immediately replacing in-service standard efficient U-frame motors with premium efficiency T-frame motors. U-frame motors were the industry standard between 1952 and 1964. Eliminating old U-frame motors simplifies the spares inventory as only T-frame motors need to be stocked in the spares warehouse. Although premium efficiency U-frame motors are available from motor manufacturers (they are often referred to as "automotive duty" motors), they carry a significant price premium; in fact, for 10-hp and 15-hp 1,800 RPM motors, the cost for a new U-frame motor is more than double the cost of an equivalent premium efficiency motor of a T-frame design.

A U-frame to T-frame conversion requires a frame adapter or transition base to line up mounting bolt holes on the base and to provide the correct shaft height. While purchase of a transition base does incur an additional motor replacement cost, this cost is offset by the typical 15% U-frame price adder to the base price for repair of a standard efficiency T-frame motor.[7-2] Transition base prices are given in Table 7-4.[7-7]

Since no repair or replacement is required, the simple payback for a U-frame motor replacement should include the full cost of purchasing and installing the premium efficiency T-frame motor plus a frame adapter, divided by the annual energy cost savings. Maintenance and plant reliability benefits will also be realized if condition assessment tests indicate that the U-frame motor is expected to fail in the near future.

Establish a Premium Efficiency-Ready Spares Inventory

A PEM-Ready spares inventory is established by identifying motor ratings and frame sizes where a number of standard efficiency motors are in operation and no premium efficiency spare is available in the event of a standard efficiency motor failure. Purchasing a block of premium efficiency motors to store in the on-site spares warehouse should ensure that a premium efficiency motor is installed when any standard efficiency or energy efficient motor fails. A failed standard efficiency motor should be recycled and a new premium efficiency motor purchased to replace the premium efficiency motor that was installed. Failed energy efficient and premium efficiency motors would be repaired and returned to the spares warehouse unless the repair cost exceeds the cost of a new premium efficiency motor. With this process, the PEM-Ready spare inventory automatically replenishes itself. The ultimate goal is to remove existing standard efficiency motors from the spares inventory so they cannot be returned to service when a standard efficiency motor fails.

A PEM-Ready spares inventory is only necessary when replacement premium efficiency motors are not immediately available from the local distributor. Depending on their size, the distributor usually has general purpose motors up to 50 hp or 100 hp in their warehouse and

Quick Fact

Unless you have a PEM-Ready spares inventory or immediate access to new premium efficiency motors from your motor distributor, a delay can occur before you can begin to capture the energy and operating cost savings expected through modifying repair/replace practices. The delay occurs because, upon the failure of an operating standard efficiency motor, a standard efficiency motor from the spares inventory would be installed whenever a premium efficiency motor was not immediately available. The failed motor would be recycled, and a new premium efficiency motor ordered as a replacement. When the premium efficiency motor arrives at the plant, it would be held in the spares inventory until the next failure of a standard efficiency motor. In the worst case scenario, the failed standard efficiency motor would be repaired and returned to service, which would eliminate the opportunity for energy and operating cost savings.

stock a variety of C-face conversion kits. Depending upon proximity, next-day delivery for motors up to 250 hp might be available from a motor manufacturer's regional warehouse. If a needed motor is in stock at a remote warehouse, the delivery time could be as long as 2 to 3 weeks. If the motor must be factory-produced, the delivery time might be as long as 10 to 12 weeks. Lag times in delivery means that motors that are critical for production will always be replaced with a standard efficiency or energy efficient motor from the on-site spares warehouse when a premium efficiency motor is not immediately available.

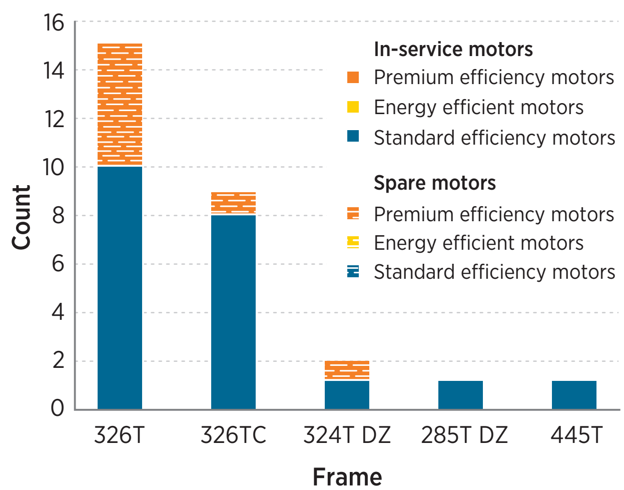

Figure 7-3. Coverage Chart for In-Service 50 hp 1,800 RPM Motors

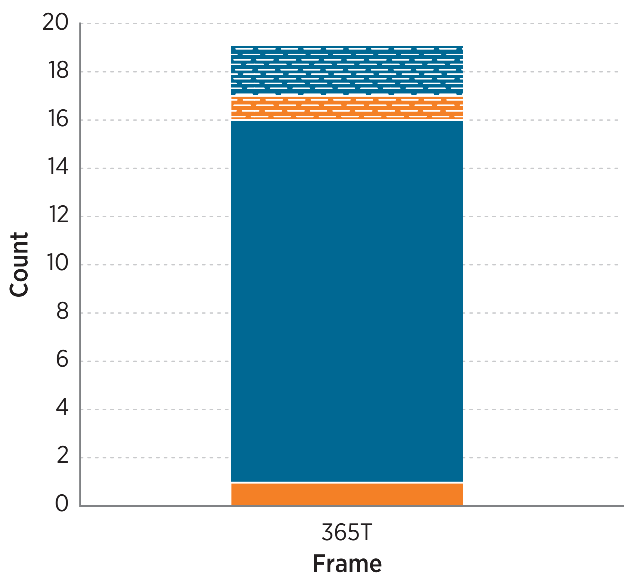

Figure 7-4. Coverage Chart for In-Service 75 hp 1,800 RPM Motors

The PEM-Ready spares inventory is established through the identification of motor ratings and frame sizes where a number of standard efficiency motors (six or more) are in operation and no premium efficiency spare is available in the event of a standard efficiency motor failure. In-service and spare motor "coverage charts" can be used to show the number of in-service and spare motors by efficiency class for each frame designation, synchronous speed, and specified motor horsepower rating. In the coverage charts shown in Figures 7-3 and 7-4, premium efficiency motors are indicated in orange with standard efficiency motors in blue. In-service motors are represented by solid colors, while spare motors are identified with cross-hatching. The plant inventory in Figure 7-3 has 10 operating standard efficiency 50-hp 1,800 RPM foot-mounted motors and eight in-service C-faced motors. As indicated by the cross-hatching and color coding, all spares are of standard efficiency design.

A spares inventory can be made PEM-Ready by pre-purchasing premium efficiency motors and holding them in the on-site spares warehouse. Procurement personnel at large industrial plants might approach their preferred motor manufacturer or local motor supplier about the possibility of maintaining a "consignment inventory" at their plant site. Industries with multiple plants within a geographical area might consider a shared or common spares inventory.

The coverage chart shown as Figure 7-4 shows a spares inventory that is PEM-Ready for 75-hp 1,800 RPM motors. This plant has 15 operating standard efficiency motors and one premium efficiency spare. Two additional standard efficiency spares are available for backup purposes but they should never be required or installed. Examination of repair work orders at two process industry plants indicates a 10-year mean-time-between-failure for low-voltage motors in the 60- to 500-hp size range.[7-8, 7-9] It is thus likely that the premium efficiency spare will be placed into service within a year.

Spares coverage charts may also be used to explore opportunities for standardizing on a single frame size, and for eliminating excess numbers of spares in some motor hp and speed ratings.

Accelerated Replacement of Low-Voltage Standard Efficiency Motors

Improving the efficiency of motor-driven equipment through replacing standard efficiency motors with premium efficiency models at the time of failure may take 15 to 20 years to complete.[7-4] Energy and cost savings would be maximized if all recommended standard efficiency motor replacements were made immediately. Purchasing a large number of motors might result in the purchaser obtaining a larger list price discount. Group motor replacements, however, are rarely done due to a longer simple payback and negative impacts on plant production.

Consider an industrial plant with a motor management plan that calls for the eventual replacement of 120 standard efficiency motors at their time of failure. The total potential annual energy savings due to installing premium efficient replacement motors are expected to exceed 2.2 million kWh per year. Assuming that 10%, or 12 of the eligible population of older standard efficiency motors is expected to fail each year, approximately 10 years would be required for the older inefficient motors to be completely removed from service.

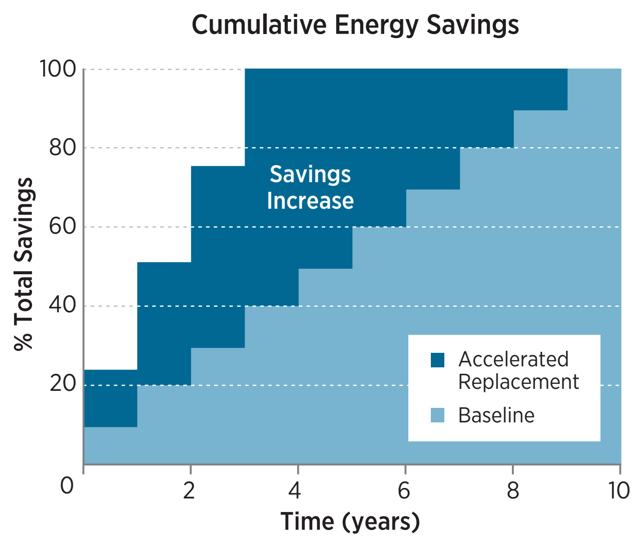

Figure 7-5. Energy Savings Increase from Accelerated Replacement of Standard Efficiency Motors

An accelerated motor replacement scenario for this example involves capturing the energy savings sooner by replacing 30 standard efficiency motors per year over a 4-year period. In the first year, this would include the 12 motors expected to fail plus an additional 18 motors. Motors in ratings that are not PEM-Ready, motors scheduled for routine cleaning, and motors that predictive maintenance programs indicate are in need of bearing replacements or other repairs would be targeted for early removal and replacement with a premium efficiency motor. These additional motor replacements would take place during scheduled maintenance shutdowns or other plant outages.

When accelerated standard efficiency motor replacement is employed, the cumulative energy savings over a 10-year period increase by 54% as shown in Figure 7-5.[7-8] Reliability benefits should also occur with accelerated replacement, as older standard efficiency motors currently account for the majority of motor failures. Benefits may include a decrease in lost production, off-quality product, chemical use, or other production costs that result from an unexpected motor failure.[7-8, 7-10]

Table 7-5. Annual Savings and Net Present Value From a 1% Efficiency Gain for Large Medium-Voltage Motors

Motor Horsepower Rating	Baseline Efficiency, %	Improved Efficiency, %	Annual Energy Savings, kWh	Annual Cost Savings[1]	Net Present Value of Savings[2]
600	94.3	95.3	22,730	$2,150	$17,660
700	94.4	95.4	26,465	$2,510	$20,580
800	94.5	95.5	30,180	$2,860	$23,410
1,000	94.8	95.8	37,490	$3,550	$29,070
1,250	95.2	96.2	46,470	$4,400	$36,060
1,500	95.4	96.4	55,530	$5,260	$43,110

[1] Savings are based on electrical rates of $0.08/kWh and $8.00/kW/month. Assumes a 70% load and 6,520 annual operating hours.

[2] The savings net present value assumes a 20-year motor operating life, a 5% annual rate of inflation or escalation of electrical energy and demand charges, and an 18% discount rate.

Improve the Efficiency of your Medium-Voltage Motors

No mandatory minimum full-load efficiency standards exist for motors rated above 500-hp. While manufacturers may market motors exceeding 500 hp as "energy efficient," "high efficiency," or "premium efficiency," these terms historically had no common definitions for either low or medium voltage motors One manufacturer's "standard efficiency" motor may be found to have a higher full-load efficiency than another manufacturer's in-service "premium efficiency" motor model. Plant staff indicate that large medium voltage motors are mainly purchased based on availability and matching frame size—not on energy efficiency.

Medium voltage motor manufacturers can often offer price quotations for a "standard" and an "improved efficiency" product. The annual energy and cost savings benefit due to a 1% gain in operating efficiency for large medium voltage motors is shown in Table 7-5 for a given set of electric rates and other assumptions. The baseline efficiency values have been recommended for use by Pacific Gas & Electric (PG&E) for their incentive programs.

The net present value of a stream of uniform energy savings can be obtained using life cycle costing techniques, such as those available in the MotorMaster+ software tool. Table 7-5 indicates that a 1% efficiency improvement on an 800-hp motor would provide an annual energy savings of more than 30,180 kWh valued at $2,150 annually for the example electric rates. The net present value of these savings is equal to $23,410 for the listed assumptions. ***This means that the purchaser of an 800-hp motor should be willing to pay a price premium of up to $23,410 to obtain a single point of efficiency improvement.*** All results are based upon a motor load of 70% with 6,520 hours of operation annually. Net present values given a 1% motor efficiency improvement for other medium voltage motor horsepower ratings are given in Table 7-5. Note that net present values are extremely sensitive to changes in future electrical energy rates and the selected discount rate. The net present values shown do not include benefits due to potentially available equipment tax credits or accelerated depreciation.

Examine Motor Repair Practices

Request that your local service center repair all motors in accordance with ANSI/EASA AR100-2010 repair best practices.[7-3] The selected service center should have a philosophy of repairing any failed motor to its original design through use of EASA guidelines. They should maintain a large stock of inverter-grade magnet wire in various wire gauges so they can install the correct wire size and replicate the original number of turns in a motor's winding pattern. A pre-repair core loss test should be conducted to determine the motor's suitability for repair. Replacement may be required if core steel is damaged from the motor failure or from previous repairs. The service center should hold their reclaiming oven temperature to 700°F to prevent core damage and always perform a post-repair core loss test.

The selected repair shop should provide a detailed "general test report" and stator "core loss test report" when a failed motor is repaired and returned to the spares warehouse. The core loss pre- and post-repair tests are desirable, as they provide the core dimensions, identify hot spots with recommendations, provide core loss test setup information, and show metered data including the core loss in watts/pound. The measured value is put into perspective by comparing it against a maximum allowable limit. Differences in watts per pound before and after repair may also indicate quality issues in the repair process.

Figure 7-6. Sample In-Service Motor Repair/Replace Tags.
Tags from Advanced Energy

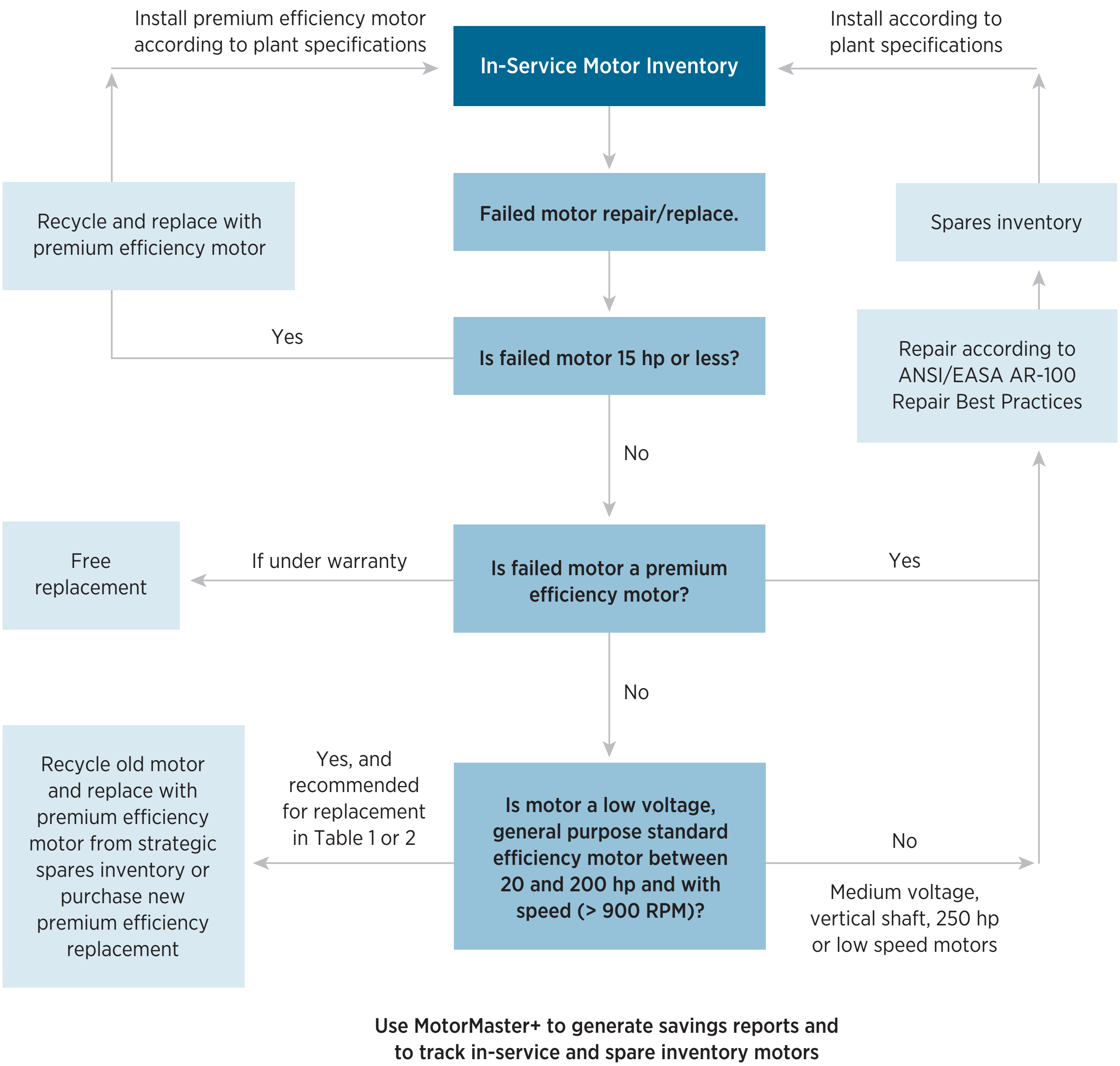

Figure 7-7. Sample Repair Versus Replace Decision Path for General Purpose Motors

A typical general test report might contain comments relating to the cause of the motor failure, nameplate data, electrical test results (insulation to ground, hipot test, surge test, phase-to-phase resistance, and a no-load test with volts and amps for each phase), mechanical data including grease type and amount of endplay, temperature readings, and vibration test results (displacement and velocity in the horizontal, vertical, and axial directions for both the drive end and opposite drive end bearings).

Prepare an Action Plan

The action plan should contain a list of recommendations from the motor management plan along with required future actions, the designation of an individual responsible for carrying out those actions, and a completion date.

The motor management plan contains recommendations regarding repair or replacement for each in-service motor. The plan might also recommend investigating the cost-effectiveness of retrofitting adjustable speed control onto motors driving pumps that use throttling valves or recirculation lines to provide flow control or with fans that operate with partially closed inlet or discharge dampers. Of particular importance is the “tagging” of these motors. All motors should be tagged so millwrights and maintenance staff can take the appropriate action(s) when an in-service motor fails. Sample motor tags developed by Advanced Energy are depicted in Figure 7-6. Tag durability is of importance. Note that these tags are fastened to the motors with metal reinforced rings and are coated in plastic to protect against moisture and grease.

It is also of use to prepare a flow chart that depicts the adopted repair versus replace practice. A sample post-motor management plan repair versus replace decision-making path is shown in Figure 7-7. Lastly, plant staff should continue to use MotorMaster+ or a comparable software tool for inventory management, maintenance logging, warranty tracking, and energy savings reporting activities.

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CHAPTER 8

SYSTEM EFFICIENCY IMPROVEMENT OPPORTUNITIES

While motor efficiency is certainly of importance, it is a relatively small contributor to overall system efficiency. System efficiency is the efficiency of converting electrical input energy into useful mechanical work. It is the useful energy output divided by the energy input. Those doing energy assessments of pumping systems might speak of the efficiency of a single component such as the motor or pump while determining the "wire-to-water" pumping plant efficiency. The wire-to-water efficiency of your pumping plant is the water horsepower provided by your pumping plant—which is proportional to the delivered fluid flow (in gallons per minute [gpm]) times the static head produced by the pump (in feet)—divided by the electrical input power supplied to the pump drive motor. The greater your overall wire-to-water or system efficiency, the lower your overall pumping costs will be.

A system can be comprised of much more than just a motor, power transmission system, and a pump. The Sankey diagram below provides a visual depiction of energy flows and losses in a typical motor-driven system. The width of an arrow in the Sankey diagram is proportional to the magnitude of an energy flow or loss. The diagram provides an illustration of how losses decrease the input energy and result in less energy being available to produce useful work. The largest losses are generally due to low driven equipment efficiency and load modulation losses due to the use of flow control devices such as pump throttling valves, fan inlet guide vanes, and fan discharge dampers.

Various methods of expressing component or system efficiency are summarized in Equation 8-1—they are all equivalent.

Efficiency
= Useful Output/Energy Input
= Useful Output/(Useful Output + Losses)
= (Energy Input − Losses)/Energy Input

Equation 8-1

An overall fan or pumping system efficiency takes into account the individual efficiencies of the fan or pump, the power transmission system (belts or gear drives), and motor efficiency, as well as load modulation device efficiency, adjustable speed drive efficiency (if present), and in-plant electrical distribution system efficiency.[8-1] Fans also have an "installation" efficiency or systems effect that accounts for decreases in fan capability due to poor installation practices that result in pressure drops due to fan inlet restrictions or obstructions and fan outlet restrictions. Examples of poor practices include turns immediately adjacent to the fan inlet or outlet.[8-1] Overall fan or pumping system efficiency is the product of the individual component efficiencies and may be determined using Equation 8-2.

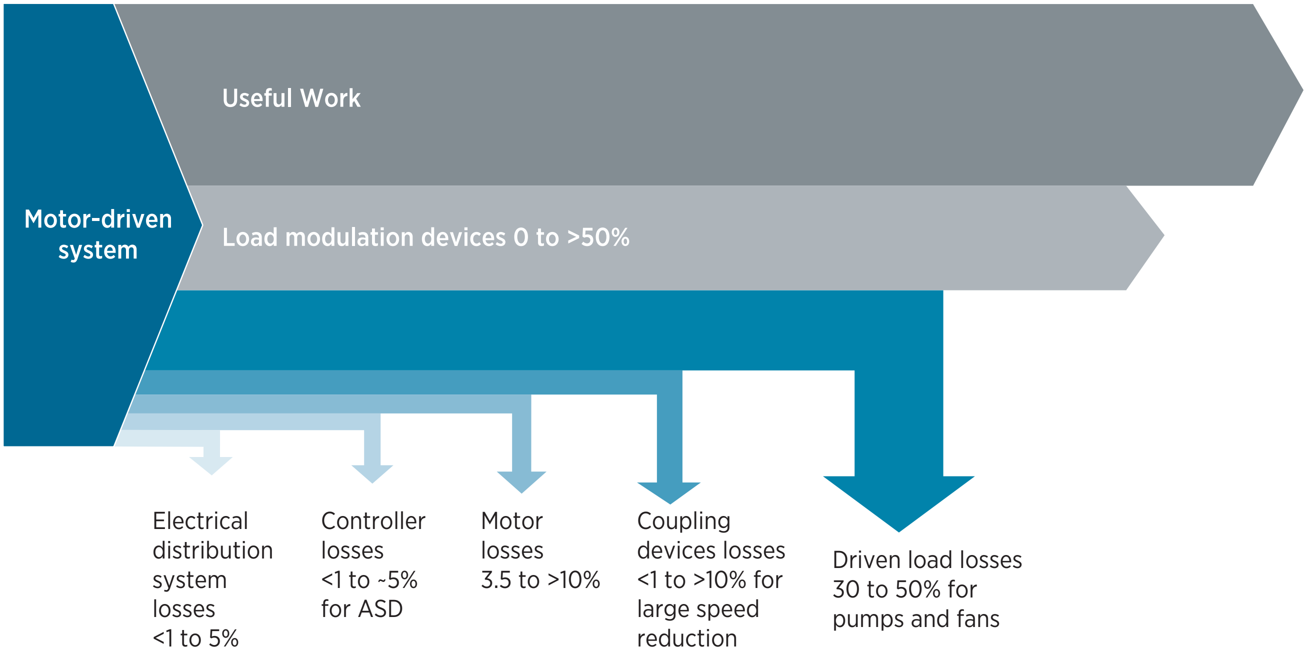


Figure 8-1. Sankey Diagram Showing Motor Driven System Losses

$$\eta\text{System} = \eta\text{Distribution system} \times \eta\text{ASD} \times \eta\text{Motor} \times \eta\text{Gear/Belt} \times \eta\text{Eqpt} \times \eta\text{Modulation} \times \eta\text{Install}$$

Equation 8-2

An example of a poorly performing system involves an oversized combustion air fan serving a wood waste burner. The combustion air flow is controlled by an outlet louver damper. Efficiencies of individual components and of the overall system follow:[8-1]

ηFan	=	55% (the fan is not operating at its best efficiency point)
ηDrive	=	96%
ηMotor	=	90% (the fan is equipped with an old standard efficiency motor)
ηControl	=	28% (damper losses)
ηInstall	=	89%% (reduction in fan efficiency due to poor installation practices)
ηDistribution	=	98% (assumed)

$$\eta\text{System} = 0.55 \times 0.96 \times 0.90 \times 0.28 \times 0.89 \times 0.98 = 0.116 \text{ or } 11.6\%$$

For this example, improving the motor efficiency to 95% would only improve the system efficiency from 11.6% to 12.2%.

Example 8-1. Determining System Efficiency

The energy savings possible from system efficiency improvements can be up to 10 times the savings due from improving the efficiency of the motor alone. As one senior product manager at a major motor manufacturer puts it, "It doesn't do much good to put a 95% efficient motor on a 50% efficient pump."[8-2]

To maximize system efficiency, one must optimize the entire drive train. By increasing the driven equipment efficiency, improving modulation efficiency, and upgrading the power transmission efficiency, you will reduce the driven equipment shaft horsepower requirements and may be able to supply the useful work with a smaller motor.[8-3]

Pipe or ducting system design and detailed rotating equipment specification and selection best practices are beyond the scope of this publication. Such energy savings opportunities should always be considered during the design phase of new facility construction or facility expansion, during major retrofit projects, when making process improvements, or at the end-of-life of equipment, such as a furnace rebuild. In addition to specifying an efficient pump, drive motor, and power transmission system, energy savings opportunities include measures that reduce the quantity of fluid pumped, decrease pressure requirements, and/or reduce operating hours. Sometimes equipment re-location can eliminate fouling concerns and allow for specification of a higher efficiency unit. For instance, placing an induced draft fan in a fume removal system downstream of the filter baghouse can allow use of a backward inclined centrifugal fan with an efficiency of 80% instead of a radial fan with a peak efficiency of 65%.

The remainder of this chapter discusses ways to identify opportunities to optimize the efficiency various components of your drive train, with an emphasis on pump and fan systems.

Matching Motor Driven-Equipment to Process Requirements

It is not unusual for motor-driven equipment to be conservatively overdesigned relative to actual process requirements. A process also might undergo radical changes after the pumps, fans, blowers, or air compressors are originally installed.[8-4] In many cases process flow requirements change when equipment is added or removed. In-plant flow balances are modified as process industries such as pulp and paper mills recycle and reuse water to achieve "zero discharge" goals or meet environmental regulations. Wastewater flows may be diverted to new on-site treatment facilities. Cooling water flows can vary due to the installation of efficient processes with lower heat rejection rates. Cooling water might be re-routed to cooling towers instead of discharged into a receiving water body. Washdown water use might change due to improved sanitary practices. Piping networks are often modified or cross-connected over time. Surface roughness and friction factors change as fluid piping systems age. Improvements or innovations in technology occur—such as nozzles requiring a high pressure drop for spray atomization being replaced with equally effective low pressure drop nozzles. The overall result is that systems that might have at one time been efficient now operate far from their original design conditions and/or best efficiency point.

To determine pump or fan efficiency, obtain the original performance curves and the impeller diameter from plant maintenance staff or from the OEM. Then gather operating information by taking field measurements or accessing existing archives of plant meter data. Industrial plants vary tremendously in their metering, data capture, analysis, and reporting capabilities.[8-5] Taking field measurements requires plant staff or a consultant to be familiar with the use of such equipment as power loggers, recording pressure transducers, thermocouples, steam vortex shedding meters, orifice or Venturi differential pressure meters, non-intrusive ultrasonic Doppler or transit time liquid flow meters, and Pitot tubes or annubars. Metering best practices are summarized in the DOE Federal Energy Management Program document, "Metering Best Practices: A Guide to Achieving Utility Resource Efficiency."[8-6]

Spot measurements might be adequate for systems with constant flow and on/off control. You should data log for at least a week to document how equipment with variable flow control to document operation by shift and on weekdays versus weekends. Sampling rate or interval depends upon the amount of system variability. Those involved with metering should have an understanding of metering standards, protocols, and equipment calibration techniques. Those working in process industries must be able to compensate and correct measurements for liquids and gases of varying compositions, densities, gas compressibility, temperatures, and fluid viscosities.

One useful technique for identifying mismatched equipment is to scale and then overlay or superimpose metered flow and pressure data onto a pump or fan curve. An example of this approach is depicted in Figure 8-2 (the metered data is plotted in blue). This plot was produced as part of a pump system upgrade study at a pulp and paper mill. As the medium voltage 250-hp pump drive motor was thought to be approaching the end of its useful life, mill staff were initially interested in upgrading to a premium efficiency medium voltage motor or a new medium voltage motor with adjustable speed drive flow control.

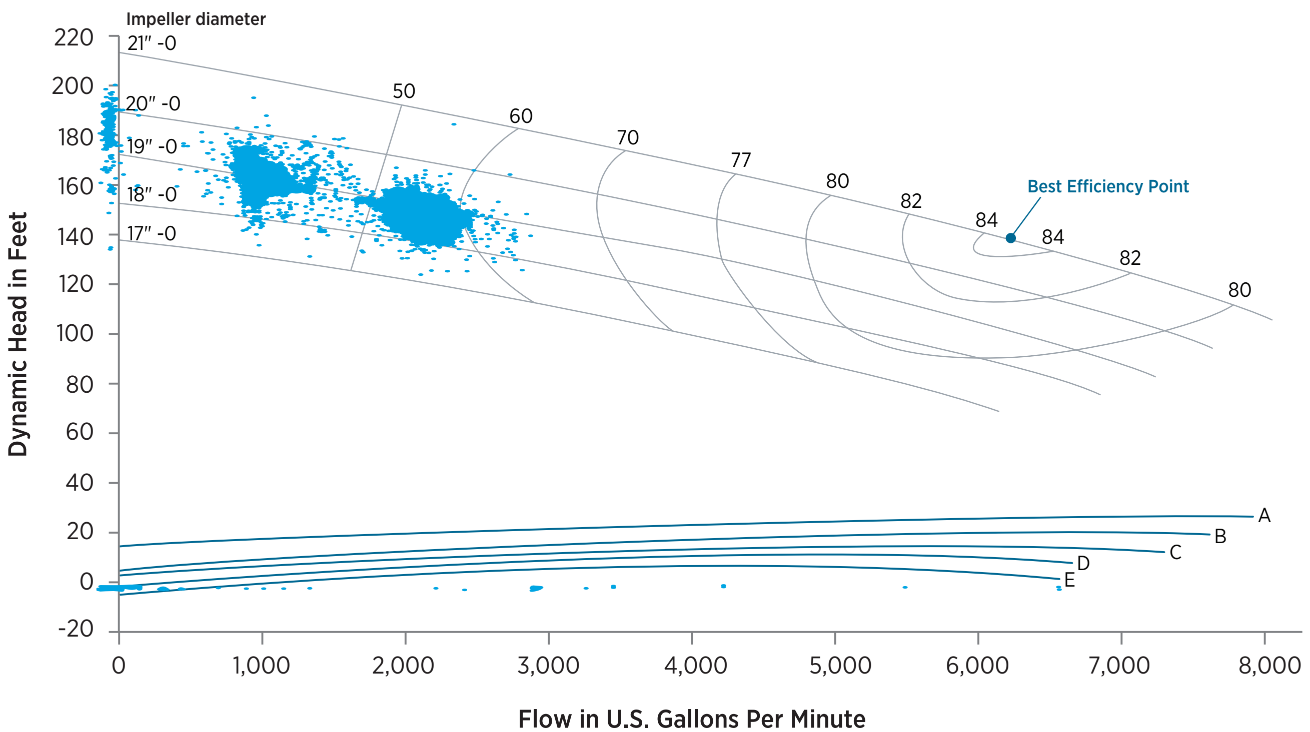


Figure 8-2. Pumping System Field Measurements Superimposed on Pump Performance Curve

A week's worth of data logging found that an adjustable speed drive would not save appreciable quantities of energy as the pump is serving a static lift application. Data logging (operating points are indicated by the blue clusters shown on the pump curve) reveals that the pump is considerably oversized for the application and operating under heavily throttled conditions and far from its best efficient point. The efficiency contours in Figure 8-2 indicate that the pump is capable of performing at an efficiency of 84% when supplying a flow rate of about 6,200 gpm at a head of 135 feet. During operation, the pump flow rarely exceeds 2,500 gpm and the weighted average efficiency is only 48%.

The recommended solution is to install a smaller pump that is sized to meet the process flow and pressure requirements. The new pump would be driven by a premium efficiency 125 hp low voltage motor that provides an efficiency improvement from 91.9% to 95.0%. Plant staff found that this motor could be supplied by an adjacent bus without causing overloads on the plant electrical system. The pump efficiency improves from 48.2% to 73.9% yielding an annual energy savings exceeding 712,000 kWh. The savings from matching equipment to process requirements amount to over 50% of the pump's baseline energy use.

$$\text{Imbalance (\%)} = \{(Qm \times Hm)/(Q_{BEP} \times H_{BEP}) - 1\} \times 100$$

Where:

Qm	=	Measured flow provided by pump (gpm)
Hm	=	Total dynamic head provided by the pump (feet)
Q_{BEP}	=	Pump flow at its best efficient point
H_{BEP}	=	Total dynamic head produced by pump at its best efficiency point

Equation 8-3

The following equation can be used to determine the level of mismatch or imbalance between driven equipment performance and process requirements. Mark the system for further review if the imbalance between actual operating and best efficiency point conditions exceeds +/- 15%. Prioritize systems for further review based upon their level of imbalance.

DOE's fan and pumping system assessment tools (PSAT and FSAT) are designed to help users determine pumping system and fan system efficiency and estimate annual energy savings given that the current pump or fan is replaced by an "optimal" unit. PSAT and FSAT do not tell users how to improve system efficiency. The tools are designed to prioritize in-service units for future study based upon their potential for efficiency improvements.[8-8] The fan and pumping system assessment tools can be obtained from AMO's Energy Resource Center *(www.eere.energy.gov/manufacturing/tech_assistance/ecenter.html)*.

Optimizing the Efficiency of Belted Power Transmission Systems

Eliminating energy losses in power transmission systems should be a high priority for the energy manager. One-third of electric motors in the commercial and industrial sectors use belt drives—with most of them using standard V-belts.[8-8] V-belts use a trapezoidal cross section to create a wedging action on the sheave groove to increase friction between the belt and the sheave and improve the belt's power transfer capability. V-belt drives can have a peak efficiency of 95% to 98% at their time of installation, but efficiency deteriorates by as much as 5% over time if slippage occurs because the belt is not periodically re-tensioned.[8-11] Increased slippage results in additional heat generation and energy losses. The efficiency of a poorly maintained V-belt may fall an additional 10%.[8-11]

The major portion of V-belt energy loss is due to bending hysteresis and sliding friction.[8-12] V-belts tend to operate at 40ºF to 80ºF above ambient temperatures.[8-13] Laboratory studies conclude that V-belt efficiency is highly dependent on transmitted torque, speed, pulley size, and the use of single versus multiple V-belts. Major findings are:[8-13, 8-14]

- Torque load has the greatest effect on belt efficiency. V-belts have low efficiencies at light loads. Power transmission efficiency generally increases with torque, but again declines at high torque loadings when slippage increases.
- Pulley diameter affects efficiency, with larger pulleys producing greater efficiency.
- Underbelted or overbelted applications become inefficient.
- Relatively large variations in efficiency occur for different V-belt designs. Narrow belts tend to produce higher efficiency at low torque while wider belts produce higher efficiencies at higher torque.

The most important parameter to control in a V-belt drive is the tension. V-belts tend to stretch during their life, causing tension to drop. If belts are too loose, they tend to vibrate, wear rapidly, and waste energy though slippage. If they are too tight, they will also show excessive wear and can dramatically shorten bearing and shaft life. The proper tension of a V-belt is the lowest tension at which the belt will not slip at peak-load conditions.[8-10] A properly installed and tensioned V-belt will last from 3 to 5 years. In harsh conditions, service life can decline to a year or less. Belt replacement more than twice a year may be an indication of a serious problem.[8-15, 8-16]

Notched Belts

To improve energy efficiency and reduce slippage losses, consider replacing V-belts with notched belts. The simple payback is improved if this action is taken at the time of a belt failure as only the incremental cost of the belt efficiency improvement measure must be considered. A notched V-belt is a direct replacement for a conventional V-belt and can use the same pulleys as an equivalent rated standard V-belt. Notched belts typically have an efficiency 2% higher than the nominal 93% efficiency of standard V-belts.[8-17] Notched belts have slots that run perpendicular to the belt's length (see Figure 8-2). The slots reduce the bending resistance of the belt. They tend to run cooler and last longer than V-belts. While their initial cost is slightly higher, their longer life means that the total cost of purchasing new and replacement belts is comparable to that for standard V-belts.

Synchronous Belts

Synchronous belts are toothed and require the installation of mating toothed-drive sprockets. They operate with an efficiency of 98% and maintain that efficiency over a wide torque range.[8-17] The recommended tension for a synchronous belt is typically less than that for a standard V-belt. This means that motor and driven equipment shaft bearings will operate under lower loads, providing a longer service life.[8-13] Synchronous belt drives have minimal heat buildup due to low bending stresses and are not prone to efficiency reductions due to slippage. Synchronous belts thus require less maintenance and re-tensioning, can operate in wet and oily environments, and are not affected by abrasive particles. However, they can be noisy, are unsuitable for shock loads, and transfer vibrations.

Rotating Equipment Speed Considerations

Centrifugal fans and pumps exhibit a strong relationship between operating speed and input power requirements. For these applications, synchronous belt sprockets must be selected that take into account the absence of belt slippage. Operating costs would increase if slippage was reduced and the centrifugal load was driven at a slightly higher operating speed. A properly designed synchronous belt drive should ensure that the final rotating equipment speed is equal to the original rotating equipment speed.

For additional information, see DOE's Motor Systems Energy Tip Sheet #5, *Replace V-Belts with Notched or Synchronous Belt Drives* (www.eere.energy.gov/manufacturing/tech_assistance/pdfs/replace_vbelts_motor_systemts5.pdf).

Figure 8-3. Notched and Synchronous Belts. A notched belt, left, runs cooler and has a higher efficiency than a standard V-belt. A synchronous belt, right, can maintain higher efficiency over a wide load range and requires minimal maintenance.
Photos from Gates Rubber Company

Gear Speed Reducer Efficiency and Choices

Gears are drive system components that are used to make the output shaft speed different from that of the input shaft speed, amplify torque, and/or change the direction of shaft rotation. Gears are commonly used when loads need to run slowly but require high torque.[8-18] Gear reducers are classified according to gear ratio (the ratio of the input to the output shaft speed). Torque is amplified in a gear reducer: for example, a 20:1 gear reducer will multiply the output torque delivered from a motor shaft by a factor of 20.

A continuously operating 100-hp supply-air fan operates at an average motor load of 75% while consuming 527,000 kWh annually. What are the annual energy and cost savings if a 94% efficient (η_1) V-belt is replaced with a 96% efficient (η_2) notched belt or with a 98% (η_3) efficient synchronous belt? Electricity is priced at $0.08/kWh.

Notched Belt:

Energy Savings
= Annual Energy Use × (1 − η_1/ η_2)
= 527,000 kWh/year × (1 − 94/96)
= 10,980 kWh/year

Annual Cost Savings
= 10,980 kWh/year × $0.08/kWh
= $878

Synchronous Belt:

Energy Savings
= 527,000 × (1 − 94/98)
= 21,510 kWh/year

Annual Cost Savings
= 21,510 kWh/year × $0.08/kWh
= $1,720

Example 8-2. Energy Savings from Replacing a V-belt with a Notched or Synchronous Belt

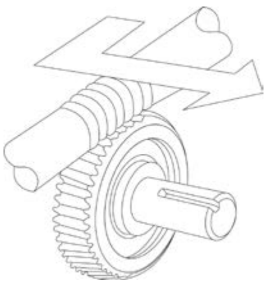
Different types of gear reducers have different performance characteristics, including the range of available gear ratios, operating efficiency, and maximum horsepower rating. Some gear reducers—such as spur gears—deliver output that is parallel to the motor shaft—while others, such as worm, helical, and bevel gears deliver output that is at right angles to the motor shaft. Characteristics for various types of gear reducers are given in the following table.[8-19]

Table 8-1. Gear Reducer Types, Gear Ratios, and Efficiency Range

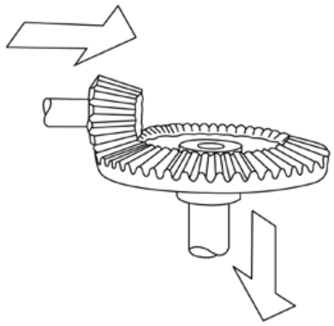
Gear Reducer Type	Gear Ratio Range	Efficiency Range (%)
Spur	1:1 to 6:1	98%–99%
Helical	2:1 to 10:1	92%–98%
Bevel	1:1 to 5:1	97%–99%
Helical/Bevel	5:1 to 200:1	92%–95%
Worm (single stage)	5:1 to 100:1	55%–94%

Worm gears are not the best choice from an energy efficiency standpoint, but they are widely used in packaging machinery, conveyors, for materials handling applications, and in pharmaceutical and food processing plants.[8-20] Worm gears are specified because they have a low initial cost, are compact, deliver high speed reductions, offer fine speed control with a long service life, feature quiet operation, and are able to withstand high overloads.[8-21] Worm gears are also inherently self-locking as the worm can drive the gear, but the gear cannot drive the worm. Depictions of worm, helical/bevel, and two-stage right-angle worm/ helical gears follow.

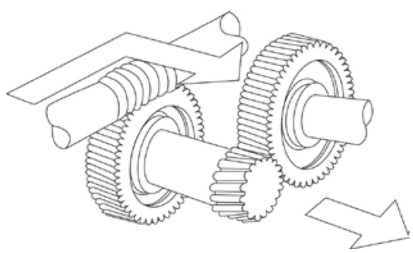
Worm Gear



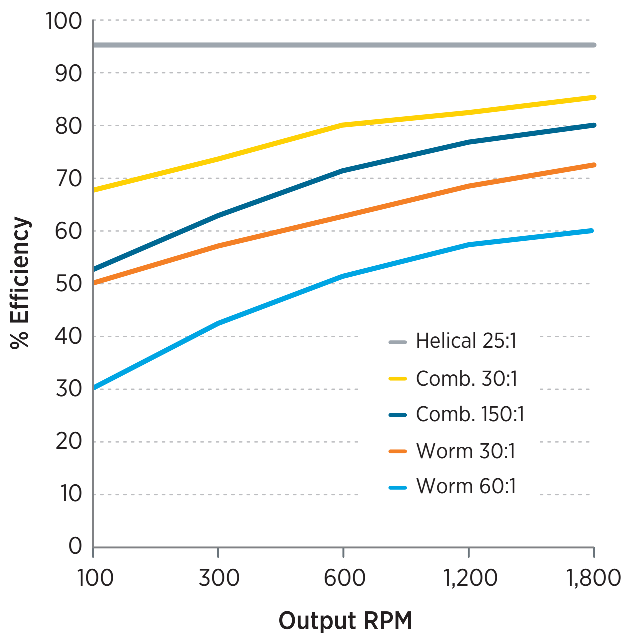
Helical/Bevel Gear



Right Angle Worm/Helical Gear



Illustrations from Baldor Electric



Note: Greater efficiency loss of worm gear at low speed

Figure 8-4. Worm Gear Efficiency Versus Gear Ratio and Output Speed. Illustration from Baldor Electric

The efficiency of a gear reducer is the output shaft power divided by the input shaft power. Power losses are associated with tooth friction, lubricant churning, seals, and windage. Frictional losses are related to gear design (how the gears intersect and mesh), gear reduction ratio, gear size, and the coefficient of friction—which depends on the type of lubricant selected. Manufacturers' catalogs often do not provide the gear reducer efficiency, but it can easily be determined from gear performance values as follows:[8-22]

Gear Efficiency (%) = [Torque × (RPM/GR)/(hp × 63,024)] × 100%

$$\text{Gear Efficiency (\%)} = \left[\text{Torque} \times (\text{RPM}/\text{GR})/(\text{hp} \times 63{,}024)\right] \times 100\%$$

Where:

Torque	=	Gear reducer output torque in inch-lbs
RPM	=	Motor shaft speed
GR	=	Gear Ratio
hp	=	Motor shaft horsepower or input horsepower to gear reducer

Equation 8-4

Figure 8-4 shows that worm gear efficiency is dependent upon both gear ratio and output speed.[8-23] Efficiency is also sensitive to drive motor horsepower rating. Worm gears are inefficient because the gears experience a sliding action instead of a rolling motion between the worm and the worm wheel. Worm gear efficiency is affected by the lead angle of the worm, sliding speed, lubricant, material selection and surface quality, and installation conditions. High losses lead to heating, so worm gears operate at much higher temperatures than other gear types. Additional worm gear efficiency reductions occur at lower input speeds, at partial loads, and with lower quality gears.

Lubrication is an essential requirement for worm gears as the worm box is designed to disperse heat to the surroundings. Efficiency can be increased and gear life extended by switching from mineral-oil based lubricants to synthetic lubricants.[8-24]

Consider the energy savings that are possible from changing out a worm gear with an end use or load requirement of 5 hp and a 50:1 gear ratio with a helical/bevel gear. The efficiency of the worm gear is 80% while the equivalent helical/bevel gear efficiency is 95%. The worm gear is driven by a 7.5 hp motor with an efficiency of 91%. Energy savings are determined with the following formula:

$$\textbf{Energy Savings (kWh)} = (5\ \text{hp}/0.91) \times 0.746\ \text{kW/hp} \times \text{hours/year} \times (1/0.8 - 1/0.95)$$

or

$$\textbf{Energy Savings (kWh)} = \text{Initial Input kW} \times \text{hours/year} \times (1 - \eta_{WG}/\eta_{HB})$$

Where:

η_{WG} = the efficiency of the worm gear

η_{HB} = the efficiency of the helical/bevel gear (in %/100)

Assuming 8,000 hours per year of annual operation, the energy savings are 6,472 kWh/year—equivalent to 15.8% of the initial or baseline annual energy use for the worm gear. At an electrical energy rate of $0.08/kWh, annual savings are $517. Additional energy savings can be obtained when an old standard efficiency gear drive motor is replaced with a new premium efficiency motor. Sometimes, increasing the gear reducer efficiency provides an opportunity to downsize the replacement motor.[8-25]

Example 8-3 Energy Savings from Use of a Helical/Bevel Gear Instead of a Worm Gear

Quick Fact

While the energy savings per unit are not huge, the number of gears in operation at a site can be substantial. For example, a large airport might utilize more than 20,000 gear reducers for conveyors and escalators, with 5,000 of these being worm gears.[8-23]

Specify high efficiency gear reducers for all new projects or upgrades of existing processes. Retrofit projects are not easy to accomplish as a trained eye and product familiarity are needed to identify worm gear drives in a plant setting (helical/bevel gears have a longer box). Focus on applications with high gear ratios. Each gearbox has its own nameplate and sometimes the manufacturer must be provided with a serial number to identify the gear type and operating characteristics. Sometimes just the gearbox can be replaced while other times an integral right angle gear drive motor must be purchased. For a worm gear, the "distance" is measured from the centerline of the worm to the centerline of the worm wheel. Physical constraints—including mounts, couplings, shaft size, and gear reducer centerline to centerline distances—can present retrofit obstacles.

Use Adjustable Speed Drives for Applications with Variable Flow Requirements

Historically, applications requiring precise speed control were satisfied by direct current motors, eddy current drives, and hydraulic couplings. Processes that required variable flow control often used a fixed speed motor with flows that regulated the opening or closing of discharge or inlet dampers or throttling valves. Fixed speed changes were obtained by changing out pulley diameters, changing gear ratios, or adjusting variable pitch fan blades.[8-26] In the 1980s and 1990s, adjustable or variable speed drives appeared on the market and offered an alternative method of flow control.[8-26] Adjustable speed drives (ASDs) are now a mature and widely used energy savings technology.

The speed at which an induction motor rotates is a direct function of the number of poles for which it is wound and the electrical supply frequency. At a constant supply frequency, an induction motor is a fixed speed device.[8-27] Because the number of poles on a standard induction motor cannot be changed after it is put into service, the only way to change its speed is to change the frequency of the supplied power.[8-27] At a frequency of 60 Hz, a four-pole motor has a synchronous speed of 1,800 RPM. If power is supplied at a frequency of 30 Hz, the motor synchronous speed is reduced to 900 RPM (see Equation 8-5). Providing a variable electrical frequency to a motor turns it from a fixed into a variable speed device. This is the principle used by the predominant form of speed control today, the pulse-width modulated (PWM) variable frequency drive.

The PWM drive consists of a rectifier, a DC link or intermediate circuit, and an inverter (see Figure 8-5). The rectifier converts AC line power to DC power. The DC link conditions the power through the use of harmonic and power ripple filters and also provides power storage using capacitors. The DC voltage is then converted back into AC power at the inverter.

The insulated gate bipolar transistors (IGBTs) used in the inverter section of the ASD have high losses when they create wave shapes other than square waves. To minimize switching losses, drive designers approximate sine waves at different frequencies while operating switches full on or full off. A square wave of much higher frequency than the fundamental is created, usually between 2 kHz and 20 kHz. This is called a carrier wave. Each "on" portion of the carrier wave is called a pulse. The duration of a pulse is called the pulse width. Long pulses produce a high average voltage and brief pulses produce a lower average voltage. The rolling average voltage provided by the drive is designed to approximate a sinusoidal waveform at the desired frequency.[8-28, 8-29] The motor current cannot respond instantaneously, so it tracks the rolling average of voltage over several pulses. Adequate torque is maintained over the entire range of motor operating speeds through regulating the output voltage to maintain a constant voltage to output frequency (V/Hz) ratio.[8-29]

Motor RPM = 120 • f / Poles

Where:

Poles = Number of motor magnetic poles

f = Power supply frequency in Hz

Typical fixed motor speeds at 60 Hz are 3,600 RPM (2-pole), 1,800 RPM (4-pole), 1,200 RPM (6-pole), and 900 RPM (8-pole)

Equation 8-5

In addition to controlling motor speed and torque, PWM ASDs can provide soft start capability (which reduces vibrations and wear on motor bearings), reduced starting current, and correct power factor to 95% upstream of the drive location. Incorporating bypass motor starters into the drive design allows the system to revert to normal constant speed operation in the event of a drive fault. Voltage boost—or the provision of higher than normal voltage to the motor at low speeds—is available for high inertia loads. A common ASD control strategy consists of using sensors and a feedback loop to vary motor and driven equipment speed to maintain pressure, flow, liquid level, torque, dimensions, or temperature at a desired setpoint.[8-30] Drives are also well suited for machine tool applications as they allow for continuous and precise speed adjustments.[8-27]

When considering an ASD for a new or retrofit application, **understanding process requirements is more important than understanding the drive itself.**[8-27] The remainder of this chapter will focus on factors that influence ASD applicability and energy savings, including:

- Types of loads encountered in industrial applications
- Flow control techniques typically used with pumps and fans
- Static head requirements

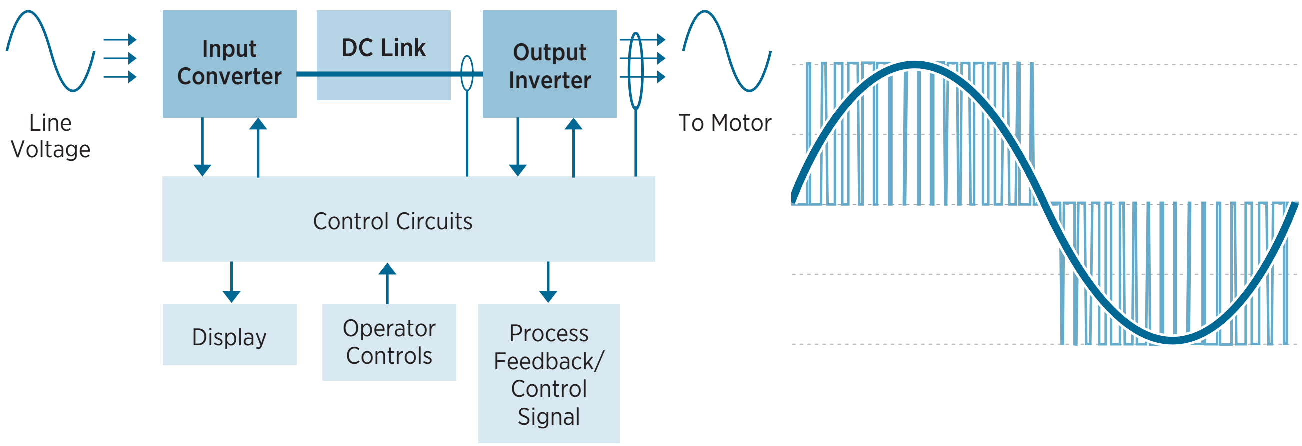


Figure 8-5. Variable Frequency Drive Components and Simulated Voltage Waveform

- Taking the field measurements necessary to determine the system curve and identify an application's load profile
- Identification of ASD efficiency improvement opportunities
- Energy savings analysis techniques.

Adverse drive/motor interactions such as voltage overshoot and shaft voltage buildup that causes current flow across a motor's bearings and appropriate mitigation techniques are discussed in the DOE's *Premium Efficiency Motor Selection and Application Guide.*

Variable and Constant Torque Loads

Driven equipment can impose three types of loads onto their drive motors: variable torque, constant torque, and constant horsepower (see Figure 8-6).[8-26] Variable torque loads exhibit a quadratic increase in torque as speed increases. Variable torque loads are typical of centrifugal fans, pumps, blowers, and air compressors, and represent about 36% of all integral horsepower industrial motors.[8-31] These loads are governed by affinity laws summarized in Equation 8-6. Affinity laws are used to predict the performance of a centrifugal pump or fan at any speed based upon pump or fan performance at the original operating point.

Affinity laws state that the change in flow rate varies directly with change in speed while the change in pump or fan horsepower requirements varies in proportion to the change in speed cubed.[8-26] Variable torque loads serving processes with variable flow requirements are particularly attractive candidates for providing energy savings with ASD flow control, as a relatively small speed change will result in a large change in driven equipment shaft horsepower requirements.[8-32] Operating a pump or fan at 75% speed will reduce the flow rate by 25% but require only 42% of the original power requirement.

A constant torque load is one in which the torque does not vary with speed. Motor shaft horsepower is equal to the delivered torque times the rotational speed. Horsepower requirements for constant torque loads vary directly with speed and affinity laws no longer apply (see Figure 8-6). Constant torque loads include conveyors, extruders, mixers, positive displacement pumps and compressors, and oil-lubricated and oil-free rotary screw air compressors. While the potential energy savings from speed reduction are not as large as those for variable torque loads, constant torque loads can provide energy savings and process control improvements.[8-26] Speed control on a conveyor taking parts or feedstock through a dryer provides process optimization capability as operators can obtain fuel-related energy savings by varying the drying time in response to variables such as feedstock moisture content. A rotary screw trim compressor with ASD control is far more efficient at part-load than the same compressor when equipped with modulating or load/unload control.[8-33] It can be cost-effective to install ASD compressors when the average loading is expected to be 75% rated capacity or less.[8-26] ASDs designed for use with constant torque loads must have higher current output capabilities at low speeds than ASDs specified for use with variable torque loads.[8-27]

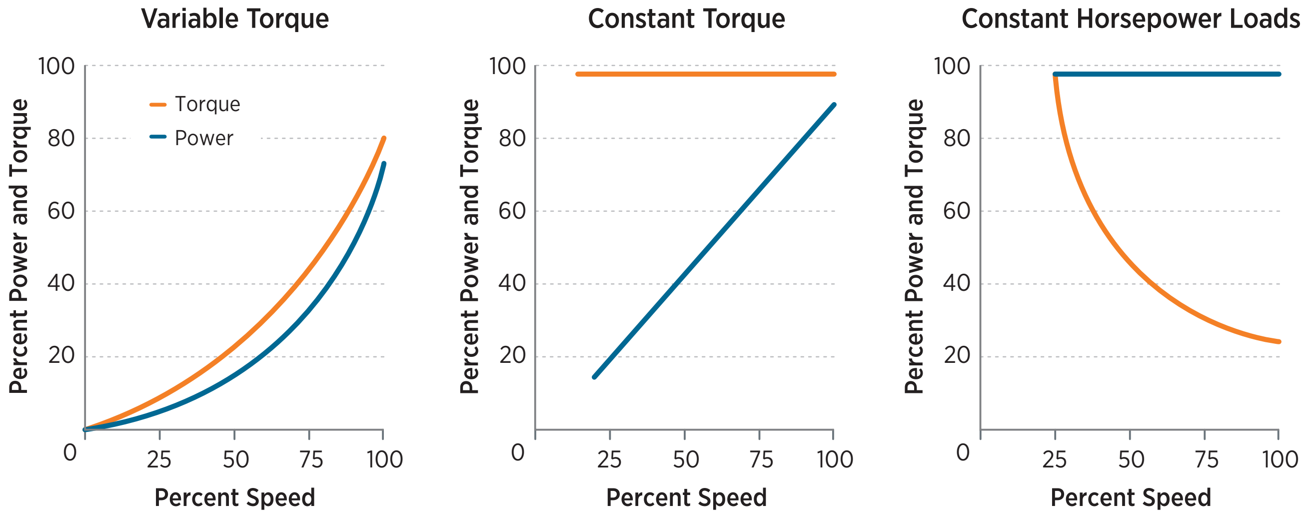


Figure 8-6. Variable Torque, Constant Torque, and Constant Horsepower Loads

At constant horsepower load, the delivered torque varies inversely with speed. Examples of this type of load include lathes, drilling, or milling machines where heavy cuts are made at low speed and light cuts are made at high speed. These applications do not provide energy savings when the driven equipment speed is reduced.[8-29]

Fan and Pump Performance Curves, System Curves, and Flow Regulation with Throttling Valves and Inlet or Outlet Dampers

Centrifugal pumps and fans can serve a wide range of operating conditions. A fan or pump characteristics or performance curve is a plot of possible pressure (head) and delivered flow operating points. Those conducting energy studies should always ask the maintenance staff for copies of pump and fan curves. If they are not available at the plant, contact the manufacturer and provide nameplate information, including the serial number. A pump curve is referenced to an operating speed and usually indicates impeller diameter, gpm, head in feet, efficiencies at different operating points, and suction head and brake horsepower requirements. A fan performance curve graphically depicts cfm, static or total pressure (in-wg), revolutions per minute, and brake horsepower requirements.[8-34] A fan curve might reflect the movement of air or industrial gases at a stated process temperature. Performance curves are independent of the system into which the pump or fan is installed.

Affinity Laws that govern centrifugal fan and pump operation are:

$$Q_2 / Q_1 = RPM_2 / RPM_1, \quad H_2 / H_1 = (RPM_2 / RPM_1)^2$$

$$P_2 / P_1 = (H_2 \times Q_2) / (H_1 \times Q_1) = (RPM_2 / RPM_1)^3$$

Where:

Q	=	Fluid flow in gallons per minute (gpm), gas volume flow in cubic feet per minute (cfm)
RPM	=	Pump or fan rotational speed, revolutions per minute
H	=	Head in feet or pressure in inches-wc (inches of water column)
P	=	Brake or shaft horsepower
Q_1, H_1, P_1, RPM_1	=	Pump or fan performance at normal (initial) operating point
Q_2, H_2, P_2, RPM_2	=	Pump or fan performance at final operating point

Equation 8-6. The Affinity Laws

A system curve is a representation of the relationship between flow and losses in a given piping or ducting system. Losses are a function of rate of flow, size (diameter or cross-sectional area), surface roughness, length of pipe or duct, and number, size, and type of valves, elbows, and fittings. Additional entrance and exit hydraulic losses occur as well as losses due to changes in pipe size by sudden or gradual enlargements or reductions in pipe diameter.[8-35] System curves are developed by those involved in process design or can be obtained by taking field measurements of pump or fan pressure and flow. A system curve shows how much pressure is required from the pump or fan to overcome system losses and produce a given fluid flow.[8-32] The system curve is independent of the pump or fan selection. The intersection of the pump or fan performance and system curves defines the actual pump or fan operating point.[8-35] This operating point is associated with a specific set of pressure, flow, efficiency, and shaft horsepower values.

Pumps and fans are often oversized. Accurately calculating friction losses or pressure drops in the piping or ducting system is a difficult task and safety margins are usually added during the design phase.[8-36] Due to this oversizing, pumps and fans are rarely called upon to operate at their rated capacity. In addition, pumps and fans are often installed in systems with multiple operating points that coincide with varying process requirements. This oversizing works against the cardinal rule of fan system efficiency: to move only the amount of air necessary because power consumption often varies with the cube of the air flow volume.[8-37]

Flow control for fans is often provided by discharge or outlet dampers, inlet guide vanes, or a combination of the two. Outlet dampers control the gas after it has passed through the fan by changing the resistance that the fan is working against.[8-38] With radial-blade and forward

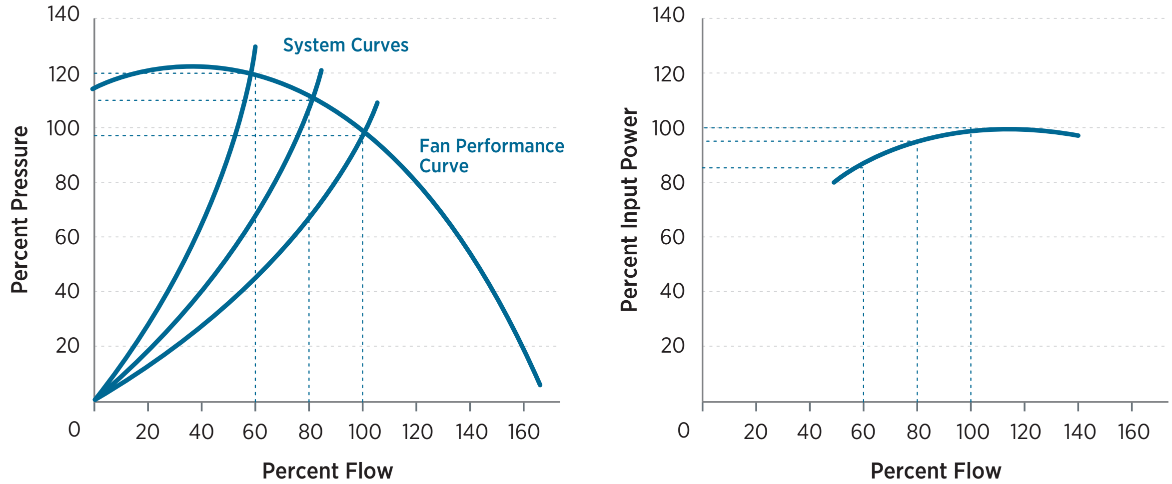


Figure 8-7. Discharge Damper Flow Regulation

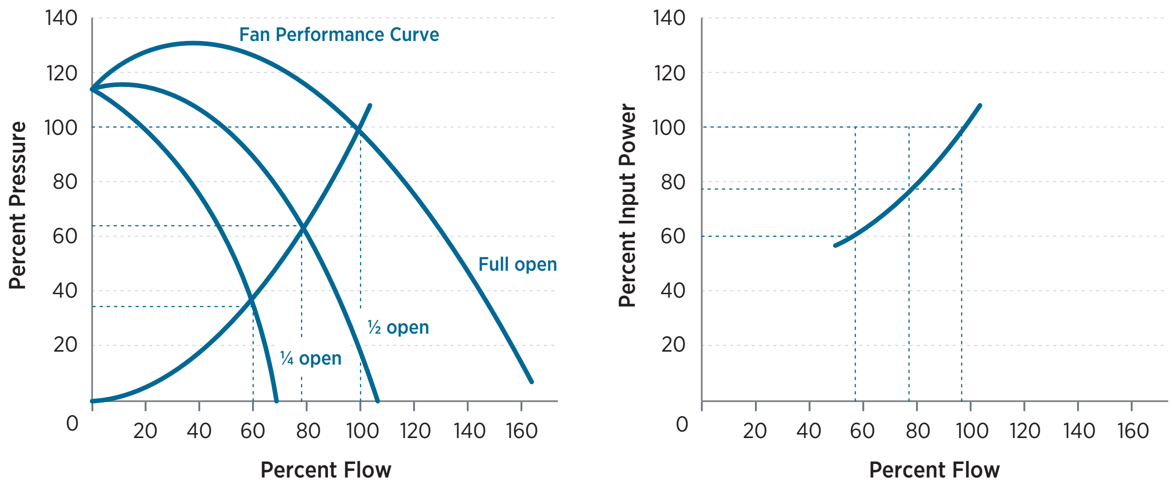


Figure 8-8. Inlet Damper or Inlet Guide Vane Flow Control

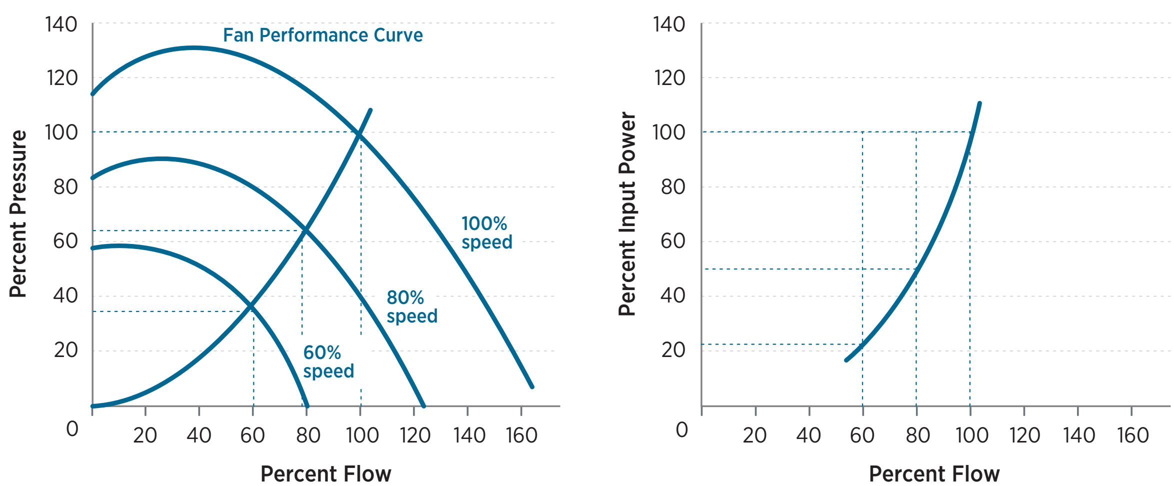


Figure 8-9. Adjustable Speed Flow Control

curved-fans, the dampered horsepower will be less than the unregulated horsepower as the fan moves to the left on its performance and brake horsepower (BHP) curves. With backwardly inclined fans, the dampered horsepower may be less, the same, or more than the wide open horsepower, depending upon the original operating point.[8-38]

Axial fans offer flow modulation when they are equipped with adjustable or variable pitch (adjustable "in flight") fan blades. Unlike fixed blade fans, adjustable pitch fans allow users to change the blade angle settings and "tune" the flow provided to meet process requirements.[8-39] Some large adjustable pitch fans cannot be re-set "on the fly." They must be shut down to allow the blade angle to be adjusted, and then restarted with the appropriate starter so the correct breakers and circuit protection are functioning. Adjustable and variable pitch blades allow for efficient flow volume control without changing the speed of the fan.[8-39]

For pumps, a throttling valve is usually employed when the process flow requirement is less than the flow provided at a pumping system's natural operating point. Similar to discharge dampers on a fan, pump throttling valves modify the system curve and provide flow control by increasing the system's resistance to flow. This increase in pressure or head requirements results in a change in the system curve due to the pressure drop and energy loss across the discharge damper or throttling valve. The operating point (defined by the intersection of the system and fan or pump performance curve) shifts to the left along the fan or pump performance curve. Fan horsepower requirements gradually decrease when discharge dampers are used to reduce flow (see Figure 8-7).[8-32] Pumps and fans that operate to the left of their best efficiency point (BEP) suffer additional losses in efficiency as operation shifts to a lower efficiency point.

Fan inlet dampers or inlet guide vanes are widely used as they are more efficient than outlet damper flow regulation. These dampers are a common volume control device because they are low in cost, require little maintenance, easily adjust airflow during operation, and require little space.[8-38] Inlet dampers pre-spin the incoming air in the same direction as the fan wheel rotation.[8-38, 8-40] This directed air movement reduces fan output pressure and airflow, thus reducing the shaft horsepower requirements that the fan imposes on its drive motor. As shown in Figure 8-8, the inlet dampers create a new fan performance curve for every damper position, intersecting the system curve at different points.[8-32, 8-40] Inlet damper flow regulation is more efficient than using outlet dampers as the horsepower requirements at reduced flows drop to a greater extent.[8-32]

ASDs are almost always more efficient than throttling valves or outlet dampers as they make it possible to adjust the flow to the demand without throttling and its associated losses.[8-36] With adjustable speed flow control, fan and pump performance curves follow the Affinity Laws and the operating point occurs at the intersection of the system curve and the reduced speed driven-equipment curve. For variable torque systems with no static lift or fixed pressure drop requirements, the input power requirements vary as the cube of the speed ratio. As shown in the "% Input Power versus % Flow" portion of Figure 8-9, ASD flow control can produce significant energy savings at reduced flows when compared to discharge damper or inlet guide van flow control.[8-31] ASD flow control is appropriate for retrofit applications or new system designs. For new systems, the capital costs of the ASD may be offset by reductions in control valve costs and conventional motor starters.[8-41]

Dampers are restricted in their ability to severely restrict airflow. When airflow is reduced by as much as 70%, flow instability or rotating stall may occur.[8-40] These conditions can result in vibration and fan casing cracking. For existing fan or pumping systems equipped with mechanical throttling valve or damper flow control, ASD flow regulation is more efficient and should be considered as a potential energy savings retrofit opportunity. After installing an ASD, a damper or throttling valve can be left fully open (or removed) with flows regulated entirely through speed control. ASD flow control can also save a considerable amount of energy in pumping systems with recirculation or bypass flow control. With this technique, the pump operates at a constant output with unnecessary discharge returned to the pump inlet or the tank from which the pump takes suction. Overall, centrifugal fan and pump applications are ideal for ASD flow regulation as they usually do not have high startup or breakaway torque requirements, there is rarely a need for high acceleration or deceleration, they are not exposed to shock loading or overloading conditions, and they do not require braking capability.[8-42]

Applications with Static Head Requirements

In a pumping system, the system curve indicates the pumping head that is required to produce a given flow rate. A system curve is comprised of both static head and dynamic or friction loss components. In the absence of static head, the system-head curve starts at zero flow and zero head.[8-35] Static head is the pressure required to overcome an elevation change or fixed pressure drop in the system. Static head requirements are independent of flow while friction head losses are generally proportional to the square of the flow rate. The system curve is represented by

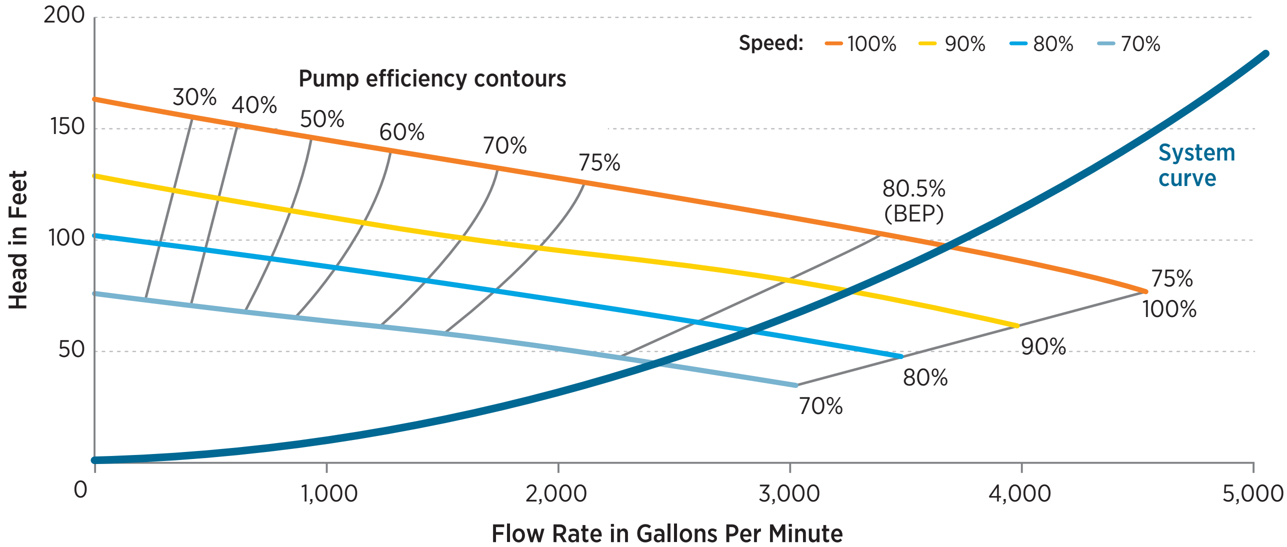


Figure 8-10. System Curve From Friction Losses Only

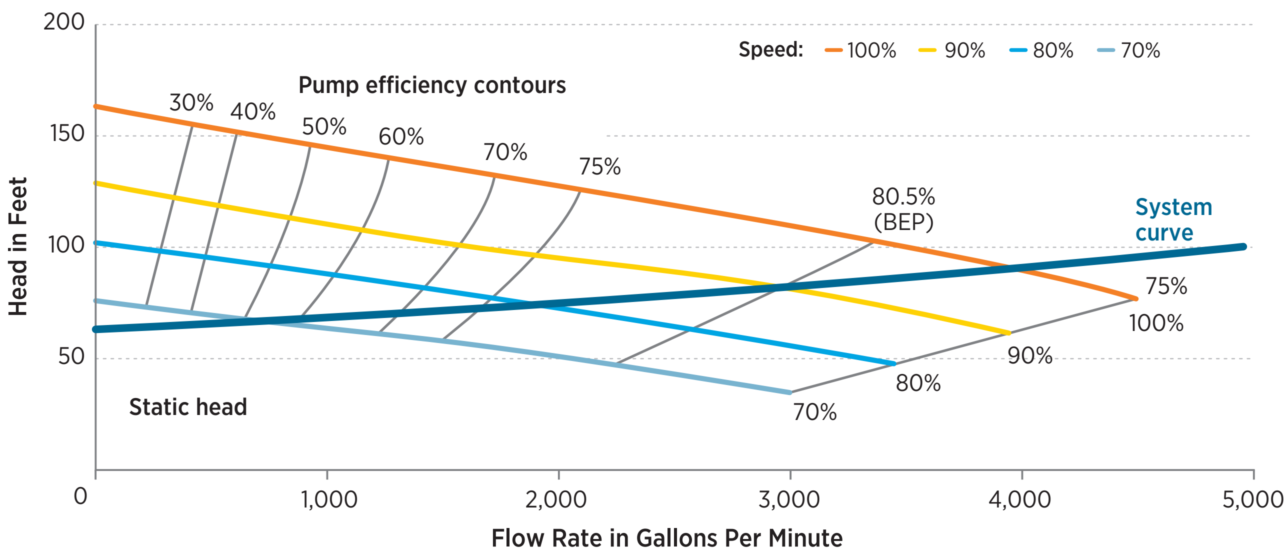


Figure 8-11. System Curve with a Static Head Requirement

a horizontal line in a pumping system with only static lift requirements. When both static lift and friction losses are present, the system curve starts at the static head and zero flow point on the head-capacity curve.[8-35] Friction losses at each flow point are added to the static life requirements to determine the system curve.

For static head dominated pumping systems, a substantial amount of the input energy is required for lifting fluid or overcoming fixed pressure requirements. An ASD cannot reduce the pumping power required to increase the potential energy of a quantity of fluid when it is raised to a higher elevation. ASD-related power reductions occur from pumping less fluid per unit of time and thereby decreasing the dynamic or friction losses in the pipes.[8-43]

Affinity laws do not apply and should not be used to estimate energy savings in systems with significant static head requirements. In static lift dominated systems, a small change in pump or fan speed can result in a large variation in fluid flow. Special care must be taken when analyzing systems with a large amount of static head. When speed is reduced with an ASD, the operating point of a pumping system rapidly shifts to the left until no fluid flow occurs and a pump is “dead-headed.” Severe damage can occur if a pump is operated under these conditions for an extended period of time.[8-36] Precise knowledge of the pump curve, pump efficiency at each operating point, and the system curve is required to determine the pump horsepower required at each discharge rate in a static head-dominated system.

Static head applications are common in industrial fan and pumping applications. Pumping examples include submersible well pumps that discharge into a reservoir or directly into a pressurized water distribution pipeline, process or booster pumps that supply water to an elevated or pressurized tank, feedwater pumps that inject returned condensate and makeup water into a fire tube or water tube steam boiler, and pumps that must overcome a fixed pressure drop in a sprinkler or spray nozzle for droplet atomization. Blowers at wastewater treatment plants with full bottom coverage aeration systems must overcome the pressure due to the water column above the bubble emitter plus the pressure drop across the diffuser. Induced draft fans often must supply a constant negative pressure at the flue of a boiler or other pickup; provide gas flows that yield a fixed pressure drop across a Venturi scrubber; or overcome the pressure drop across the filter fabric in a baghouse.

Figure 8-10 shows a system curve for a system that is totally dominated by friction losses, such as a circulating hot water loop in a heating system.[8-41] The operating point (3,500 gpm, 90 feet of head) is just to the right of the BEP for this system. As the pump speed is reduced, delivered flow and pressure decreases but the pump efficiency remains above 80%. This is because efficiency isopleths (lines of constant pump efficiency, shown in white in Figure 8-10) and the system curve (shown in dark blue) both move toward the zero-flow/zero-head origin on the head/capacity graph (see Figure 8-10).[8-41]

A system dominated by static head requirements behaves in a different manner. Small changes in pump or fan speed result in large changes in flow. The system curve shown in Figure 8-11 has a static requirement of 65 feet and intersects the pump curve at the same operating point as Figure 8-10.[8-41] In the friction dominated system, the flow rate would be about 2,400 gpm at 70% speed with the pump efficiency maintained at around 80%. When the speed of the pump is reduced to 70% of its original operating speed in the static head application, the flow rate is reduced to about 800 gpm and the pump efficiency decreases to about 55%.

In a system with **only** static head, the pump efficiency loss effect is even more dramatic and energy use could increase if an ASD was used for flow regulation. In the example shown, the pump would "dead-head" and provide no flow whatsoever if operated at 70% speed. The pump is not capable of producing enough pressure to overcome static lift requirements and move water. Energy savings potential decreases as static head—expressed as a percentage of total system head requirements—increases.[8-27] On-off control of pumps is a very efficient flow control strategy for high static lift applications, such as a well pump delivering water to an elevated reservoir.

Duty Cycle and Load Profiles

The duty cycle for a system indicates how many hours per year it is in operation. The load profile shows how process flow requirements fluctuate when the system is in operation. Valuable information is often available from operating records, discussions with operating staff, plant supervisory control systems, or continuous emissions monitoring equipment. For instance, boiler steam production and exhaust gas flow and temperatures at the plant stack might be available at 14-minute intervals over the preceding operating year. Given variable boiler steam production, a week's worth of power logging might allow the energy manager to determine baseline the annual energy use and the load profile for the boiler's forced or induced draft fan.

Field measurements often must be made to determine the load profile. Liquid flow measurements can be logged with a non-intrusive transit-time flowmeter. A recording annubar can be used to determine gas flows over time. An RMS power meter should be used to determine input power to the driven-equipment drive motor over the same time the flow measurements are taken. Recording data for at least a week is recommended.

Once flow measurements are made, separate the available data into flow "bins." Each bin might represent a range of flow values, for instance greater than or equal (>=)30% and < 35% of full-flow. Count the number of measured flow values in each bin and divide by the total count to determine the fraction of operating time associated with each bin. A histogram graphically depicts an application's flow profile or variable flow requirements by indicating the percentage of operating time that flows fall within each specified flow range. ASD energy savings increase when duty cycles are high and the system operates far from its full-flow operating point. Figure 8-12 illustrates a load profile that indicates an "excellent" ASD retrofit opportunity. Figure 8-13 shows an application that is not as attractive as the one shown in Figure 8-12, but still offers "good" ASD energy savings potential. A "poor" ASD retrofit candidate is indicated by the load profile in Figure 8-14.[8-27] Remember that an ASD will actually increase energy consumption at full-flow due to losses in the drive's power electronics.

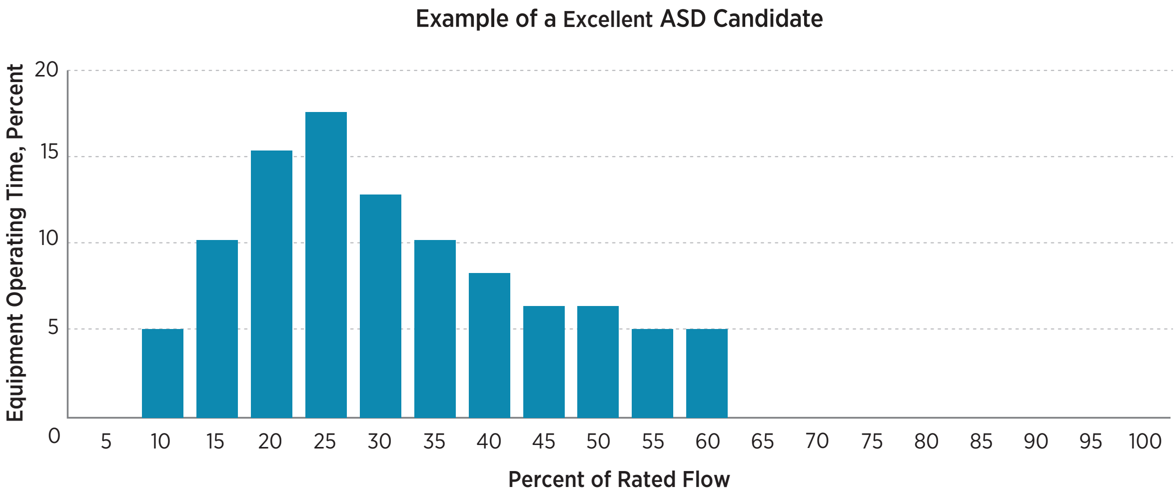


Figure 8-12. A Load Profile that Indicates an Excellent ASD Retrofit Opportunity

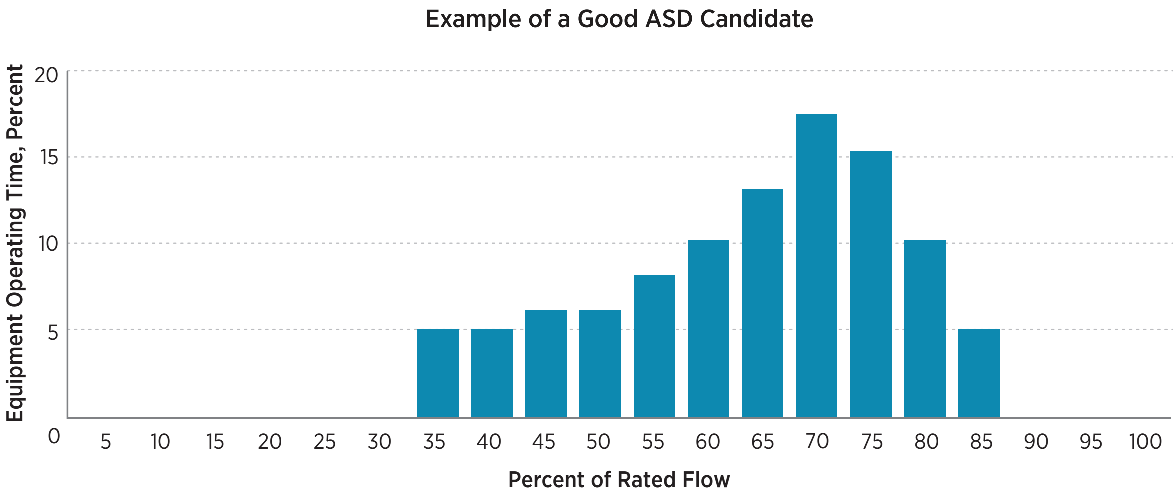


Figure 8-13. A Load Profile that Indicates a Good ASD Retrofit Opportunity

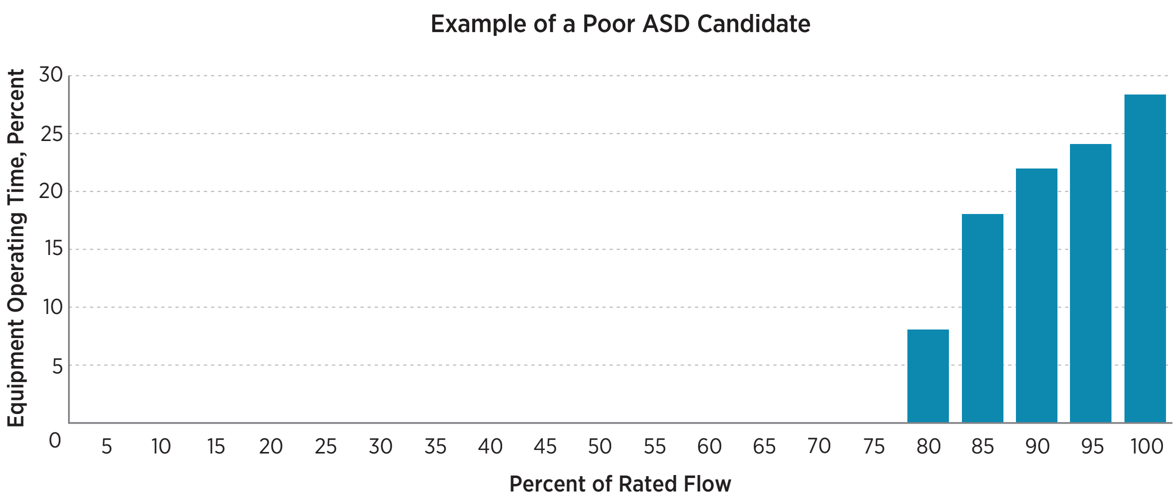


Figure 8-14. A Load Profile that Indicates a Poor ASD Retrofit Opportunity

A duty cycle that indicates throttling or damper control is employed to provide a constant flow that is less than full-flow indicates that other efficiency measures should be considered. These might include changing out pulley sizes for belted loads, trimming a pump impeller, replacing the equipment drive motor with one with a lower synchronous speed (such as replacing an 1,800 RPM motor with a 1,200 RPM motor), or replacement of an oversized fan or pump with one that is matched to load requirements.

Electronic ASDs should be considered as potential replacements for adjustable belt pulley drives, hydraulic or fluid drives, and eddy current clutches.[8-44] See DOE Motor Systems Tip Sheet #12, *Is it Cost-Effective to Replace Old Eddy-Current Drives? (www.eere.energy.gov/manufacturing/tech_assistance/pdfs/motor_tip_sheet12.pdf)* for more information on this potential energy savings opportunity.

In addition to duty cycle and load profile, ASD cost-effectiveness is strongly affected by utility rates and possible utility incentives for the investment in efficient equipment. ASDs might be desirable to plant management for reasons other than energy savings. When examining an ASD retrofit project, secondary benefits should be quantified to the degree possible. Advantages of ASDs can include:[8-30]

- Improved process control
- Better controllability/controls speed variations or swings
- Fast response
- High acceleration and deceleration
- Increased productivity
- Improved product quality/reduction in reject rates
- Increased equipment life
- Eliminates startup impacts causing system vibrations
- Reduced maintenance costs
- Regeneration
- Supports low current soft starts
- Provides fault tolerance
- Power factor improvement
- Can restart spinning loads
- Less downtime.

Part-Load Efficiency of Motors and Adjustable Speed Drives

The input power to a pump is proportional to the hydraulic horsepower produced divided by the product of the pump efficiency, motor efficiency, and drive efficiency at their respective operating and load points.

When a pump is throttled, its operating point is at the intersection of the pump performance curve and the desired flow rate. When ASD flow control is used, the operating point is at the intersection of the systems curve and the desired flow rate. The hydraulic horsepower is proportional to the product of the delivered head times the flow at the operating point. The pump shown in Figure 8-15 provides about 900 gpm at a head of 41 feet when running

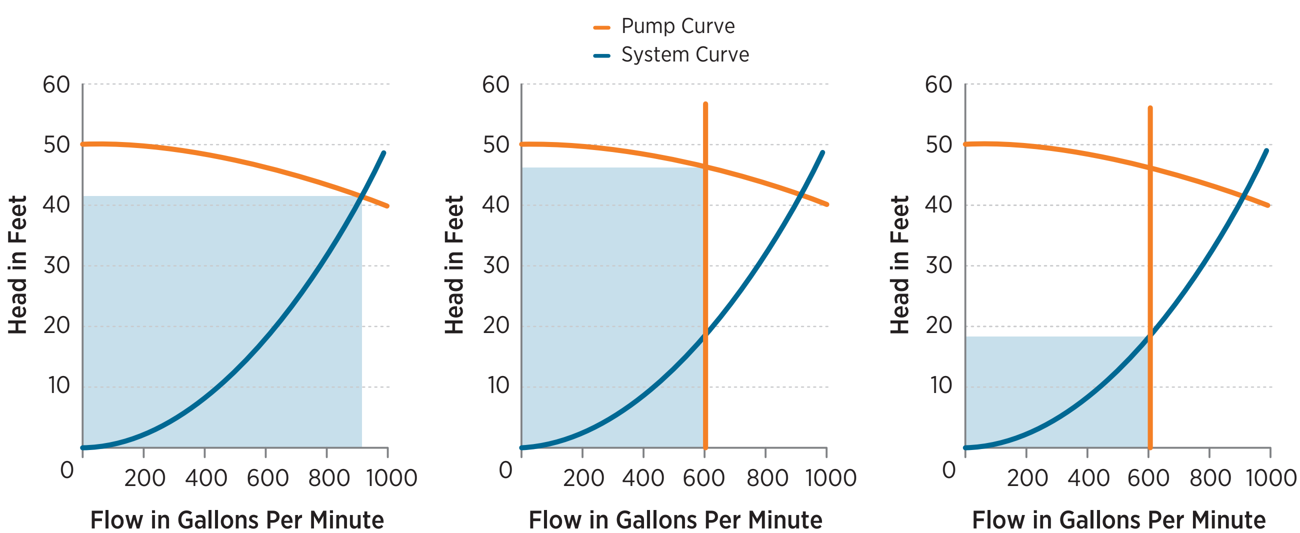


Figure 8-15. Pump with Unregulated Flow, Throttled Flow Control, and ASD Flow Regulation

$$P = (Q \times H \times SG) / (K \times \eta_{PUMP} \times \eta_{ASD} \times \eta_{MOTOR})$$

Where:

P	=	Input power in kW
Q	=	Fluid flow in gallons per minute
H	=	Head developed by the pump in feet
K	=	Constant equal to 5,308 for the units given
SG	=	Specific gravity of the fluid being pumped
η_{PUMP}	=	Efficiency of the pump at its operating point
η_{ASD}	=	Efficiency of the ASD at its operating speed and torque
η_{MOTOR}	=	Efficiency of the motor at its load point

Equation 8-7

$$P = (CFM \times SP) / (K \times \eta_{FAN} \times \eta_{ASD} \times \eta_{MOTOR})$$

Where:

P	=	Input power in kW
CFM	=	Volume flow rate (ft^3/min)
SP	=	Static pressure produced by the fan (in-wg)
K	=	Constant equal to 8,520 for the units given
η_{FAN}	=	Efficiency of the fan at its operating point
η_{ASD}	=	Efficiency of the ASD at its operating speed and torque
η_{MOTOR}	=	Efficiency of the motor at its load point

Equation 8-8

at its natural operating point. When throttled to provide a flow of 600 gpm, the head increases to about 46 feet. Use of an ASD for flow control provides the same flow (600 gpm) with a head requirement of only 19 feet. Hydraulic horsepower requirements—proportional to the shaded areas shown in Figure 8-15—are significantly reduced.

The input power required by a pump drive motor is: Similarly, the input power required by a fan drive motor is:[8-45]

To determine fan or pump input power requirements at each operating point, the fan or pump, ASD, and motor efficiencies must be determined. Fan and pump efficiencies can be obtained from performance curves, or, in cases where pump wear and loss of performance is expected; by taking electrical, fluid flow, and pressure measurements and then calculating the rotating equipment efficiency using Equations 8-7 and 8-8.

There is currently no recognized standard for ASD efficiency although the Canadian Standards Association (CSA) has proposed a draft standard CSA C838 that uses the output/input method to determine ASD motor and motor/drive system efficiency. The IEC also released draft standard 60034-2-3 for the determination of motor efficiency when fed by a converter waveform.[8-46]

ASD losses are comprised of two components: conduction losses and switching losses.[8-47] Conduction losses do not vary with switching frequency and are equal to the product of the voltage drop across the drive and the current passing through the drive. Switching losses increase in proportion to switching frequency.[8-47] Both losses result in heat production and elevated drive temperatures.

Test laboratories are beginning to test ASDs to determine their efficiency both with and without being coupled to a drive motor. By testing at four speeds (100%, 75%, 50%, and 25% of rated) and four loads (100%, 75%, 50%, and 25% of full-rated torque) an efficiency contour map can be created.[8-48] The efficiency map shown in Figure 8-17 is a new approach to presenting drive and motor performance and illustrates how the combined ASD and drive motor

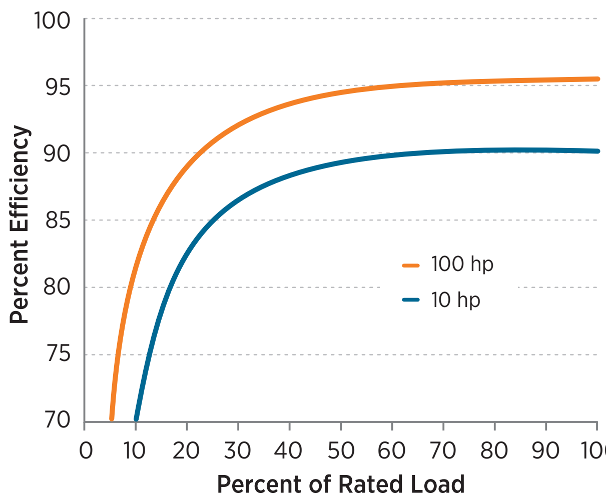


Figure 8-16. Motor Efficiency Versus Load Curves

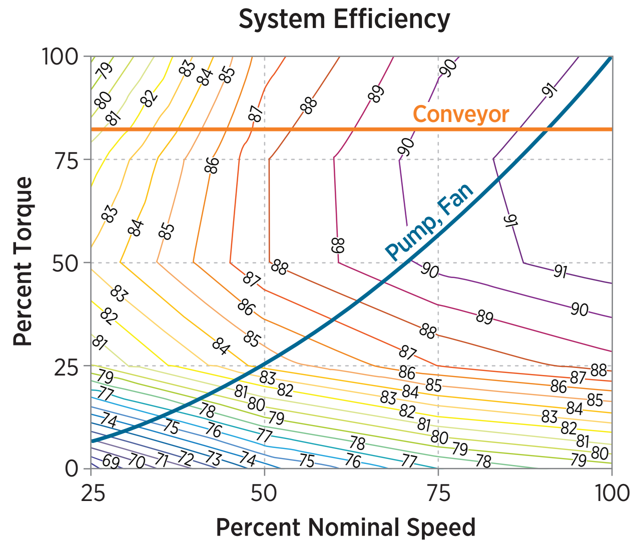


Figure 8-17. Motor and Adjustable Speed Drive Efficiency Contour Map

Quick Fact

ASD efficiency decreases when the drive is lightly loaded, with the decline in efficiency more pronounced with drives of smaller horsepower ratings. This reduction in efficiency is not as detrimental as it might seem. Consider an ASD coupled to a motor that delivers 50 hp to an exhaust fan. When the fan is operated at 50% of its rated speed, the combined motor and drive efficiency is approximately 84%. At 50% of its rated operating speed, the fan delivers 50% of its rated airflow, but requires only one-eighth of its full-load power. Even with this lower motor/drive efficiency, the power required by the fan is reduced from 50 hp to 7.4 hp—a reduction of 42.6 hp or 85.2% of the original fan power requirement. If the motor/ASD had maintained its full-load efficiency of 92%, the power required by the fan would decrease to 6.8 hp, leading to an additional savings of only 0.6 hp. This motor/ASD efficiency improvement increases the previously estimated savings by only 1.4%.

efficiency varies with delivered torque and speed. The solid lines indicate speed and torque operating points for variable and constant torque loads. Remember that delivered shaft horsepower is equal to the product of torque and speed divided by 5,252, when speed is in RPM and torque is given in foot-pounds.

Additional considerations are efficiency impacts due to ASD and motor temperature, switching or carrier frequency, voltage level and voltage unbalance, drive control software, and the losses due to specification of power conditioning equipment such as line and load reactors and/or harmonic filters.[8-48]

Additional information on ASD part-load efficiency is available from the DOE's Motor Energy Tip Sheet #11, *Adjustable Speed Drive Part-Load Efficiency* *(www.eere.energy.gov/manufacturing/tech_assistance/pdfs/motor_tip_sheet11.pdf)*.

Conducting an ASD Energy Savings Analysis

Once the duty cycle and load profile have been determined, and the input power to the pump or fan drive motor has been monitored, it is fairly straightforward to complete an ASD energy savings analysis. The measured input power values show how the power requirements of the existing system respond to changes in flow given use of the current flow control method. Overlay your system curve on your fan or pump curve and estimate the brake horsepower requirements for the pump or fan at each operating point given ASD flow regulation. Remember that for each flow the operating point will always fall on the system curve. Use the fan or pump and estimated ASD and motor part load efficiency values to determine input power requirements at each operating point using Equations 8-7 or 8-8.

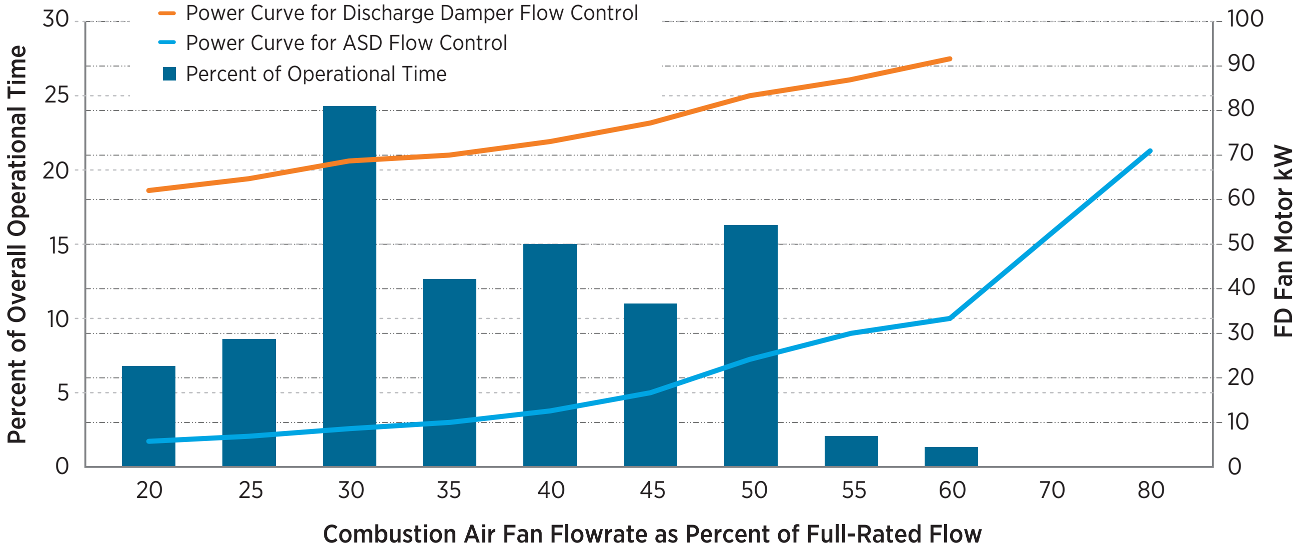


Figure 8-18. Load Profile, Baseline, and ASD Power Requirements Curves for a Combustion Air Supply Fan

Table 8-2. Energy Savings Due to Retrofit of an ASD onto a Centrifugal Fan with Discharge Damper Flow Control

% of Rated Flow	% of Operating Time	Annual Operating Hours	Discharge Damper Control, kW	ASD Flow Control, kW	Savings, kWh per year
60	1	80	91	34	4,560
55	2	160	86	30	8,960
50	17	1,360	82	23	80,240
45	12	960	76	15	58,560
40	15	1,314	72	11	80,154
35	13	1,040	70	10	62,400
30	24	1,920	68	9	113,280
25	9	720	65	7	41,760
20	7	560	62	6	31,360
Total Expected Annual Energy Savings, kWh					**481,274**

All of the information necessary for an energy savings analysis is shown on Figure 8-18. The load profile or percent of operating time at each flow point is indicated in blue and is read on the left vertical axis. The orange curve shows how the measured power responds to changes in flow when fan outlet dampers are used. Input kW values are shown on the right vertical axis. The light blue curve shows the estimated input power requirements for the 200 hp drive motor given the use of ASD flow control for the same fan. Expected input kW values are again shown on the right axis. The power savings at each operating or flow point is the difference between the kW requirements when outlet dampers are deployed less the power required when ASD flow control is provided.

An ASD energy savings analysis can quickly be done on a spreadsheet after using a regression analysis to provide equations that replicate or "fit" the outlet damper and ASD input power responses to changes in flow. A bin analysis is shown in Table 8-2 for the combustion air fan performance depicted in Figure 8-18 assuming an 8,000-hour duty cycle.

The energy savings analysis shows an expected energy savings of 481,274 kWh per year. This annual energy savings is $38,500 given an energy cost of $0.08/kWh. The total installed cost would be approximately $42,000 for a 200-hp rated ASD in a filtered NEMA 1 enclosure, with automatic bypass control, circuit protection, a 3% line reactor, dV/dt filter, and with a shaft grounding brush for the fan drive motor. The simple payback for this project is about 1.1 years.

Additional information on how to identify and analyze ASD retrofit opportunities is available in the DOE Pumping Systems Tips Sheets #11, *Adjustable Speed Pumping Applications* *(www.eere.energy.gov/manufacturing/tech_assistance/pdfs/motor_tip_sheet11.pdf)* and #12, *Control Strategies for Centrifugal Pumps with Variable Flow Rate Requirements* *(www.eere.energy.gov/manufacturing/tech_assistance/pdfs/38949.pdf)*. Also refer to the DOE publication, *Improving Motor and Drive System Performance: A Sourcebook for Industry.*

Quick Fact

ASDs are sometimes used to slow a large fan or pump drive motor down during short time intervals when process requirements are reduced or do not exist. Large motors cannot be shut down and restarted due to heat production in the motor windings due to high starting currents. Reducing the speed of an 1,800 RPM motor to 400 RPM is almost equivalent to turning it off as, for variable torque loads, the input power requirement of the load drops to only1% of its full-flow value. Examples include washdown or spray systems while a new rail car is being positioned, control of mine ventilation fans during zero staff in mine periods, and control of air pollution control equipment baghouse fans when an electric arc furnace is removed for tapping.

Table 8-3. NEMA Designated Enclosures for Electrical Equipment

Designation	Protection
NEMA 1	Enclosure designed for indoor use protecting components within from physical contact with operating and maintenance personnel.
NEMA 3R	Enclosure designed for outdoor use. These enclosures protect against falling rain, sleet, and external ice formation.
NEMA 12	Enclosure designed for indoor use. Provides protection against dust and dripping liquids, including protection against fibers, lint, dust, dirt, and non-corrosive dripping liquids.
NEMA 4	Enclosure designed for indoor and outdoor use. Protects against dirt, dust, splashing water, falling water, seepage, hose-directed water, and external condensation.
NEMA 4X	Same as NEMA 4 except the enclosure is corrosion resistant.

ASD Selection Considerations

The output rating of an ASD should be based upon the motor nameplate rated full-load current.[8-47, 8-49] ASDs should not be selected based upon motor horsepower rating. The motor must be selected and/or protected against ASD-induced voltage overshoots and shaft bearing currents (see "Motor Interactions with Adjustable Speed Drives" and "Guidance for Selecting Motors Controlled by an ASD" sections from DOE's *Premium Efficiency Motor Selection and Application Guide).*

Ensure that your ASD comes in an enclosure that is suitable for your site environmental conditions. Following is a summary of NEMA enclosure designations:[8-49]

NEMA Standard 250 contains additional information on enclosure classifications. For NEMA 1 enclosures, ventilation air may be required for cooling purposes. Depending upon site conditions, filtered air may be required. The ASD enclosure should be equipped with space heaters if the ambient temperature is expected to dip below freezing (0ºC).[8-47, 8-49]

ASDs can be equipped with a number of control techniques. Volts to hertz (V/Hz) control maintains a constant ratio between the drive's output voltage and frequency to provide a constant full-load torque over the drive's speed or operating range. Vector control separately controls the magnetizing flux producing and torque producing currents supplied to the motor. The result is accurate speed and torque control that is comparable to that obtained with a DC motor.[8-49]

Voltage boost is often provided with V/Hz control when the motor is operated at frequencies below 20 Hz. This capability is necessary to provide sufficient locked rotor and breakaway torque without requiring excessive current.[8-47]

Bypass control (also called isolation and bypass control) is often desirable or required for reliability, redundancy, or safety purposes. This capability allows the motor to be run by the power system when the ASD trips off-line due to a fault condition.

For additional information on operating motors with ASDs, refer to the following:

- NEMA 2001 Standard Publication *Application Guide for AC Adjustable Speed Drive Systems*
- IEC Technical Specifications *Rotating Electrical Machines: Part 17: Cage Induction Motors When Fed From Converters—Application Guide,* IEC/TS 60034-17:2006
- IEC Technical Specifications *Rotating Electrical Machines: Part 25: Guidance for the Design and Performance of AC Motors Specifically Designed for Converter Supply,* IEC/TS 60034-25:2007.

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CHAPTER 9

POWER FACTOR CORRECTION

Overview

Power factor is a measure of how effectively electrical power is being used. A high power factor (approaching unity) indicates efficient use of the electrical distribution system; a low power factor indicates poor use of the system.[9-1]

Many loads in industrial electrical distribution systems are inductive. Examples include motors, transformers, fluorescent lighting ballasts, and induction furnaces.[9-1] The line current drawn by an inductive load has two components: magnetizing current and power-producing current.

The magnetizing current is the current required to sustain the electromagnetic flux or field strength in the machine. This component of current creates reactive power that is measured in kilovolt-ampere reactive, or kVAR. Reactive power does not do useful "work," but it circulates between the generator and the load. It places a heavy drain on the power source, as well as on the distribution system of the power source.

The real (working) power-producing current is the current that reacts with the magnetic flux to produce the mechanical output of the motor.[9-2, 9-3] Real power is measured in kilowatts and can be read on a wattmeter. Real (working) power and reactive power together make up apparent power. Apparent power is measured in kilovolt-amperes or kVA. See Figure 9-1 and Equation 9-1.

Power factor is the ratio of real power to apparent power. To determine power factor (PF), divide real power (kW) by apparent power (kVA). In a sinusoidal system, the power factor is also referred to as the cosine θ.

$$\mathbf{PF} = \frac{\mathbf{P}}{\mathbf{P_{APP} \times 24 \times N}} = \mathbf{cosine}\ \theta$$

Where:

PF	=	Power factor as decimal
P	=	Three phase power in in kW
P_{APP}	=	Apparent power in kVA
θ	=	Phase angle difference between voltage and current wave forms

Equation 9-1

Another way to visualize power factor and demonstrate the relationship between kW, kVAR, and kVA is the right "power" triangle illustrated in Figure 9-1. The hypotenuse of the triangle represents the *apparent* power (kVA), which is the system voltage multiplied by the amperage times the √3 (for a three-phase system) divided by 1,000. The right side of the triangle represents the *reactive* power (kVAR). The base of the triangle represents the *real* or working power (in kW). The angle between the kW and the kVA legs of the triangle is the phase angle θ.[9-4]

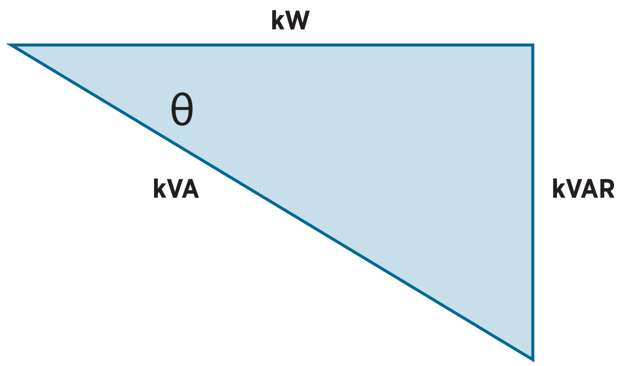


Figure 9-1. The Power Triangle

If a sawmill requires a metered demand of 1,000 kW and the measured apparent power is 1,250 kVA, you would divide 1,000 by 1,250 to obtain a power factor of 0.80. **The phase angle is arc cosine 0.80 or 36.9 degrees.**

Example 9-1

Power factor is also referred to as *leading* or *lagging*. In the case of the magnetizing current, the power factor is lagging in that the current follows the voltage waveform. The amount of lag is the electrical phase angle between the voltage and the current. Displacement power factor is equal to the cosine of the phase angle between the voltage and current waveforms.

Power Factor Penalties

When a utility serves an industrial plant that has poor power factor, the utility must supply higher current levels to serve a given load. In a situation in which real power demand (kW) at two plants is the same, but one plant has an 85% power factor while the other has a 70% power

Terminology

Apparent Power (kVA)

This value is determined by multiplying the current times the voltage. In a three-phase circuit, multiply the average phase-to-phase voltage times the average line current times the square root of 3 divided by 1,000. The units are kVA.

$$P_{APPARENT} = \frac{V \times I \times \sqrt{3}}{1{,}000}$$

Reactive Power (kVAR)

This term describes the magnetizing requirements of an electric circuit containing inductive loads. The value of magnetizing power is determined by multiplying the apparent power (kVA) by the sine of the phase angle, θ, between the voltage and the current. Units are kVAR.

$$P_{REACTIVE} = P_{APPARENT} \times \text{sine } \theta$$

Real or Working Power (kW)

Electricians use this term when referring to plant loads. Real power is related to apparent power by the cosine of the phase angle, θ, between voltage and current. Units are kW.

$$P_{KW} = P_{APPARENT} \times \text{cosine } \theta$$

$$P_{KW} = P_{APPARENT} \times PF$$

factor, the utility must provide 21% more current to the second plant to meet the identical real power requirement. Conductors and transformers serving the second plant would need 21% more carrying capacity than that provided to the first plant. Additionally, resistance losses (I^2R losses) in the distribution conductors in the second plant are increased by 46%.[9-2, 9-3] A low power factor may also lower your plant's utilization voltage, increase electrical distribution system line losses, and reduce the in-plant distribution system's capacity to deliver electrical energy.

A utility is paid primarily on the basis of energy consumption (kWh) and peak monthly demand (kW). Without a power factor billing element, the utility would receive no more income from the second plant than it does from the first. As a compensation for supplying the extra current, utilities often establish a "power factor penalty" in their rate schedules. A minimum power factor value is established, often set at 95%. When the customer's power factor drops below the minimum value, the utility collects "low power factor" revenue. As shown in the "Benefits of Power Factor Correction" section of this chapter, the lower the actual power factor, the greater the penalty.[9-2, 9-3]

Power Factor Improvement

Induction motors are generally the principal cause of low power factor because many motors are in use that are not fully loaded.[9-5] When motors operate near their rated load, the power factor is high. For lightly loaded motors, however, the power factor drops significantly. This effect is partially offset as the total current is less at reduced load. Lower power factor does not necessarily increase the peak kVA demand because of the accompanying reduction in load.

Power factor can also be improved through replacement of standard efficiency with premium efficiency motors, which are appropriately matched to their driven loads. Power factors vary considerably based on motor design and load conditions. While some premium efficiency motor models offer power factor improvements of 2% to 5%, others have lower power factors than typical equivalent standard motors. Even motors with high power factor are affected significantly by variations in load. A motor must be operated near its rated loading in order to realize the benefits of a high power factor design.

Power factor can also be improved and the cost of external correction reduced by minimizing operation of idling or lightly loaded motors and by avoiding operation of equipment above its rated voltage. While motor full-and part-load power factor characteristics are important, they are not as significant as nominal efficiency. When selecting a motor, conventional wisdom is to purchase based on efficiency and correct for power factor.[9-6]

Some strategies for improving your power factor follow:

- **Use a motor with the highest speed that an application can accommodate.** Two-pole (nominal 3,600 RPM) motors have the highest power factors; power factor decreases as the number of poles increases.[9-7]
- **Choose motor sizes that are as close as possible to the horsepower demands of the load.** A lightly loaded motor requires little real power. A heavily loaded motor requires more real power. Since the reactive power is almost constant, the ratio of real power to

apparent power varies with induction motor load, and power factor ranges from about 10% at no load to as high as 85% or more at full load.[9-2, 9-3, 9-7] (see Figure 9-2). An oversized motor draws more reactive current at light load than a smaller motor draws at full load.

Low power factor results when motors are operated at less than full load. This often occurs in cyclic processes (such as circular saws, ball mills, conveyors, compressors, grinders, extruders, or punch presses) for which motors are sized for the "worst case" or heaviest load expected to be encountered. In these applications, the power factor varies from moment to moment. Examples of situations in which low power factors occur (from 30% to 50%) include a surface grinder performing a light cut, an unloaded rotary screw air compressor, and a circular saw spinning without cutting.[9-1] The industries shown in Table 9-1 typically exhibit low power factors and do not fully use the incoming utility-supplied current.[9-1, 9-8]

- **Add power factor correction capacitors to your in-plant distribution system.** Low power factors can be corrected by installing external capacitors at the main plant service or at individual pieces of equipment. Power capacitors serve as leading reactive current generators and counter the lagging reactive current in the system. By providing reactive current, they reduce the total amount of current that your system must draw from the utility.[9-1]

Helpful Tip

To help you improve the power factor of motor-driven systems, the Bonneville Power Administration has produced an Industrial Power Factor Analysis Guidebook.[9-8] The guidebook addresses the following topics:

- How to tell if your plant could benefit from capacitors
- How to select capacitor schemes to eliminate power factor penalties and minimize losses
- How to perform detailed plant surveys to collect sufficient data to determine where to put capacitors
- Why the power system must be built with extra capacity to supply power
- How reactive power contributes to additional losses
- How capacitors, synchronous machines, and static (adaptive) power compensators correct for power factor
- When to use switched versus fixed capacitors
- How and when capacitors contribute to harmonic distortion problems, and how to predict this
- How capacitors can fall prey to harmonics and switching transients, and what to do about it.

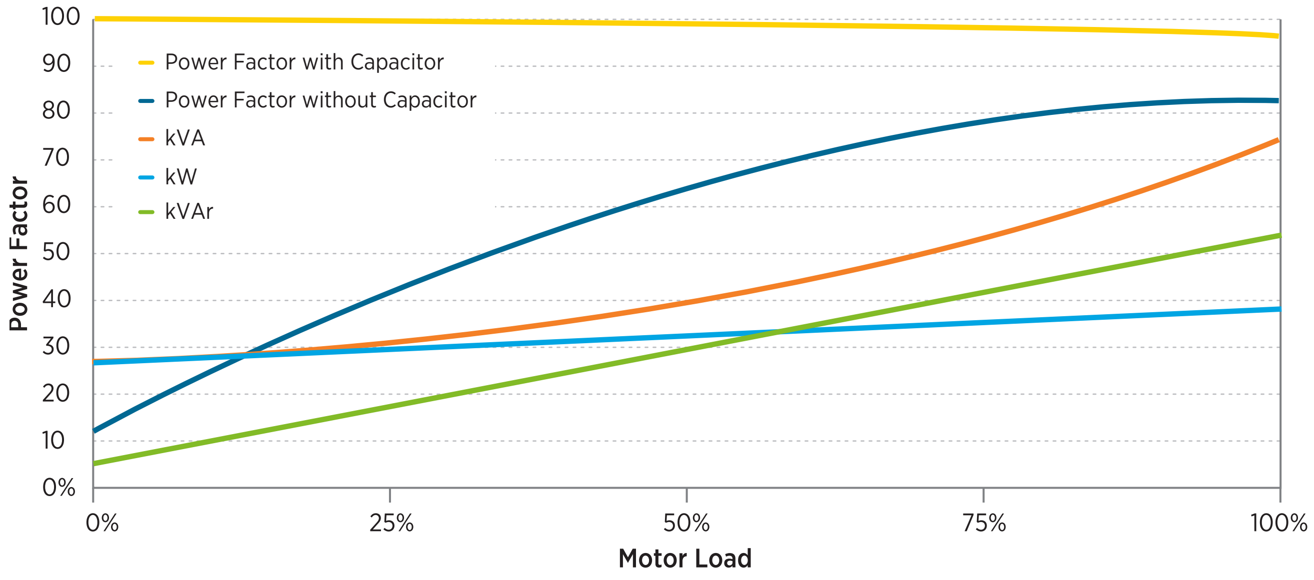


Figure 9-2. Power Factor as a Function of Motor Load

Table 9-1. Industries that Typically Exhibit Low Power Factor[9-1, 9-8]

Industry	Uncorrected Power Factor
Saw mills	45% – 60%
Plastics (extruders)	55% – 70%
Machine shops	40% – 65%
Plating, textiles, chemicals, breweries	65% – 75%
Foundries	50% – 80%
Chemicals	65% – 75%
Textiles	65% – 75%
Arc welding	35% – 60%
Cement works	78% – 80%
Printing	55% – 70%

Sizing and Locating Power Factor Correction Capacitors

Once you decide that your facility can benefit from power factor correction, you will need to choose the optimum type, size, number, and strategic locations for capacitors in your plant. The unit for rating power factor capacitors is the kVAR, which is equal to 1,000 volt-amperes of reactive power. The kVAR rating signifies how much reactive power a capacitor will provide.[9-1]

The value of individual motor reactive power is cumulative toward the overall plant reactive power. Therefore, when you improve the power factor of a single motor, you are reducing the plant's reactive power requirement. Although power factor correction capacitors reduce current in the lines supplying the motor, they do not reduce motor current, input power requirements, or performance.

The greatest power factor correction benefits are obtained by placing capacitors at the source of reactive currents. It is common to distribute capacitors on motors throughout an industrial plant.[9-8, 9-9] This is a good strategy when capacitors must be switched to follow a changing load. If your plant has many large motors (e.g., 25 hp and above), it is usually economical to install capacitors at each motor, and switch the capacitors and motor on at the same time.[9-1]

Switched capacitors do not require separate switch control equipment when they are on the load side of motor contactors. Capacitors installed on the larger motors are nearly as economical as fixed banks installed at motor control centers. When some switching is required, the most economical method is to install a base amount of fixed capacitors that are always energized, and to place the remainder on the larger motors so they can be switched when the motors are energized. Observing load patterns will allow you to determine good candidate motors for receiving capacitors.

If your plant contains many small motors (in the .5 to 10 hp range), it can be more economical to group the motors and to place single capacitors or banks of them at (or near) the motor control centers. If capacitors are distributed for loss reduction and need to be switched, you can install an automatic power factor controller in a motor control center; this approach provides automatic compensation and is more economical than placing capacitors on each of the small motors fed from that control center.[9-8] The best solution for plants with large and small motors is often to specify both types of capacitor installations.[9-1, 9-8]

Sometimes, only an isolated trouble spot requires power factor correction. This may be the case if your plant operates welding machines, induction heaters, or DC drives.[9-1] Facilities with very large loads typically benefit from a combination of individual load, group load, and banks of fixed and automatically switched capacitor units.

Advantages of individual capacitors at the load include the following:[9-1]

- They provide complete control; capacitors do not cause problems on the line during light load conditions.
- There is no need for separate switching; the motor always operates with its capacitor.
- Motor performance improves when the voltage delivered to the motor increases due to reduced voltage drops.
- Motors and capacitors can easily be relocated together.
- It is easier to select the right capacitor for the load.
- Line losses are reduced.
- In-plant electrical distribution system capacity is increased.

The advantages of bank installations downstream of the utility meter at the plant substation or service entry include the following:[9-1]

- The cost per kVAR is lower.
- Installation costs are also lower.
- The total plant power factor improves, which reduces or eliminates utility power factor penalty charges.
- Total kVAR may be reduced because all capacitors are on line even when some motors are switched off.
- Automatic switching ensures the exact amount of power factor correction and eliminates over capacitance and resulting overvoltages.

If your facility operates at a constant load around the clock, fixed capacitors are the best solution. If the load is variable, such as two 7-hour production shifts, followed by a nighttime cleanup shift 5 days per week, you will need switched units to decrease capacitance during times of reduced load.[9-1]

If your feeders or transformers are overloaded, or if you wish to add additional load to already loaded lines, you should apply power factor correction at the load. If your facility has excess current-carrying capacity, you can install capacitor banks at main feeders.

There are three location options for installing capacitors at the motor, as indicated in Figure 9-3. These options, along with the types of motors applicable to each, are as follows:[9-1]

Location A — At the motor side of the overload relay

- New motor installations, in which overloads can be sized in accordance with a lower current draw
- Existing motors, when no overload change is required

Location B — Between the starter and overload relay

- Existing motors, when placement at location A would allow overload current to surpass code

Location C — At the line side of the starter

- Motors that are jogged or reversed (jogging refers to service conditions that include repeated starting and stopping of a motor such as moving a crane or a conveyor to a particular location)
- Multispeed motors
- Starters with open transition, and those that disconnect/reconnect the capacitor during cycle
- Motors that start frequently
- Motor loads with high inertia.

Sizing Capacitors for Individual Motors and Entire Plant Loads

Capacitors that are installed across the motor terminals and switched with the motor should not be sized larger than the amount of kVAR necessary to raise the motor no-load power factor to 100%.[9-7] Use Table 9-2 to size capacitors for individual motor loads; look up the type of motor frame, synchronous speed (RPM), and horsepower.

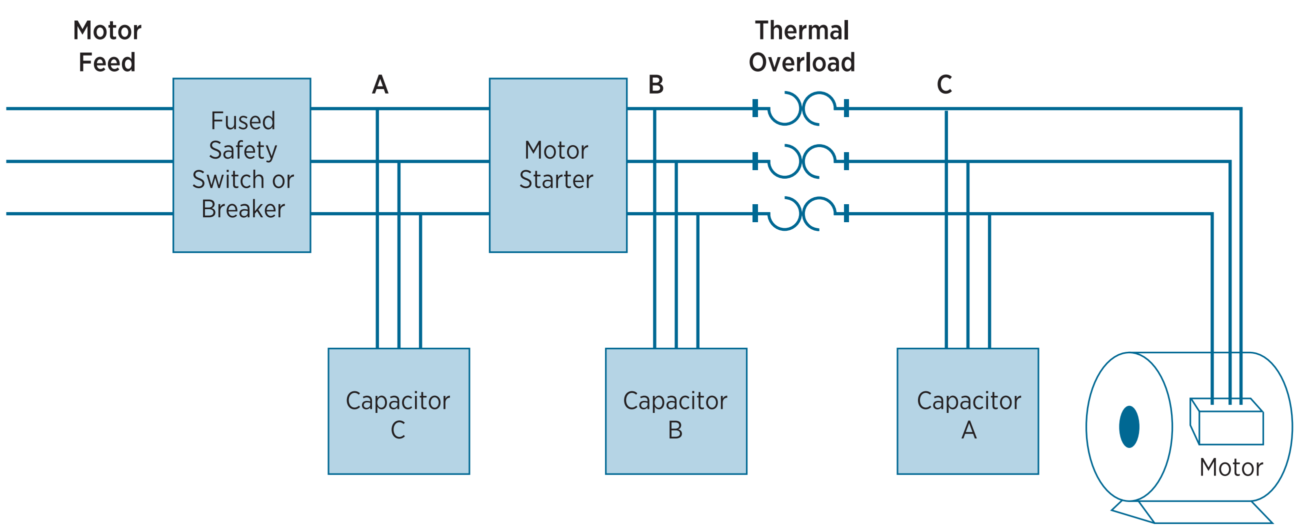
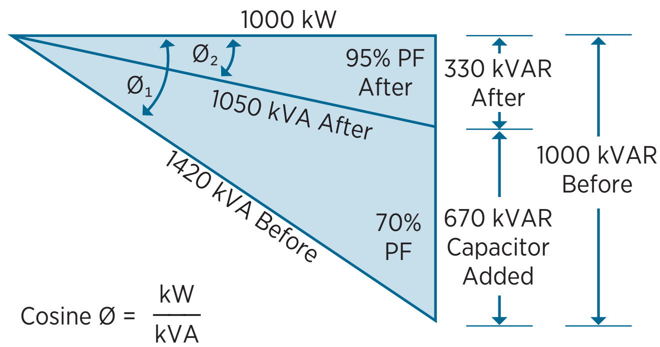


Figure 9-3. Locating Capacitors on Motor Circuits

The table indicates the kVAR necessary to correct the power factor to 95%.[9-1]

If you know the total plant load (kW), your present power factor, and the power factor you intend to achieve, you can use Table 9-3 to identify the required capacitance.[9-1] This table is useful for sizing banks of capacitors that can be located at motor control centers, feeders, branch circuits, or the plant service entrance.

The power triangle in Figure 9-4 indicates the demands on a plant distribution system before and after adding capacitors to improve power factor. Increasing the power factor from 70% to 95% reduces the apparent power from 1,420 kVA to 1,050 kVA, *a reduction of 26%.*



$$\text{Cosine } \varnothing = \frac{\text{kW}}{\text{kVA}}$$

$$\text{Cosine } \varnothing_1 = \frac{1000}{1420} = 70\%\ \text{PF}$$

$$\text{Cosine } \varnothing_2 = \frac{1000}{1050} = 95\%\ \text{PF}$$

Figure 9-4. Apparent Power Requirements Before and After Adding Power Factor Correction Capacitors

Table 9-2. Sizing Guide for Capacitors on Individual Motors[9-1]

NEMA Code	B																		C		D	Wound Rotor
	Before 1955						U-Frame						T-Frame									
Poles	2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12	4-6	8	6	
RPM	3,600	1,800	1,200	900	720	600	3,600	1,800	1,200	900	720	600	3,600	1,800	1,200	900	720	600	1,800 1,200	900	1,200	
HP=3	1.5	1.5	1.5	2	2.5	3.5	1	1	1	2			1.5	1.5	2.5	3	3	4				
5	2	2	2	3	4	4.5	1	2	2	2			2	2.5	3	4	4	5				
7.5	2.5	2.5	3	4	5.5	6	1	2	4	4			2.5	3	4	5	5	6				
10	3	3	3.5	5	6.5	7.5	2	2	4	5	5	5	4	4	5	6	7.5	8				
15	4	4	5	6.5	8	9.5	4	4	4	5	5	5	5	5	6	7.5	8	19	5	5	5	5.5
20	5	5	6.5	7.5	9	12	4	5	5	5	10	10	6	6	7.5	9	10	12	5	6	6	7
25	6	6	7.5	9	11	14	5	5	5	5	10	10	7.5	7.5	8	10	12	18	6	6	6	7
30	7	7	9	10	12	16	5	5	5	10	10	10	8	8	10	14	15	23	7.5	9	10	11
40	9	9	11	12	15	20	5	10	10	10	10	15	12	13	16	18	23	25	10	12	12	13
50	12	11	13	15	19	24	5	10	10	15	15	20	15	18	20	23	24	30	12	15	15	18
60	14	14	15	18	22	27	10	10	10	15	20	25	18	21	23	26	30	35	18	18	18	20
75	17	16	18	21	26	33	15	15	15	20	25	30	20	23	25	28	33	40	19	23	23	25
100	22	21	25	27	33	40	15	20	25	25	40	45	23	30	30	35	40	45	27	27	30	33
125	27	26	30	33	40	48	20	25	30	30	45	45	25	36	35	42	45	50	35	38	38	40
150	33	30	35	38	48	53	25	30	30	40	45	50	30	42	40	53	53	60	38	45	45	50
200	40	38	43	48	60	65	35	40	60	55	55	60	35	50	50	65	68	90	45	60	60	65
250	50	45	53	58	70	78	40	40	60	80	60	100	40	60	63	82	88	100	54	70	70	75
300	58	53	60	65	80	88	45	45	80	80	80	120	45	68	70	100	100	120	65	90	75	85
350	65	60	68	75	88	95	60	70	80	80			50	75	90	120	120	135				
400	70	65	75	85	95	105	60	80	80	160			75	80	100	130	140	150				
450	75	68	80	93	100	110	70	100					80	90	120	140	160	160				
500	78	73	83	98	108	115	70						100	120	150	160	180	180				

Table 9-3. Multipliers to Determine Capacitor kVAR Required for Power Factor Correction[9-1]

Original Power Factor	Corrected Power Factor																		
	0.80	0.81	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.89	0.90	0.91	0.92	0.93	0.94	0.95	0.96	0.99	1.0
0.50	0.982	1.008	1.034	1.060	1.086	1.112	1.139	1.165	1.192	1.220	1.248	1.276	1.306	1.337	1.369	1.403	1.440	1.589	1.732
0.51	0.937	0.962	0.989	1.015	1.041	1.067	1.094	1.120	1.147	1.175	1.203	1.231	1.261	1.292	1.324	1.358	1.395	1.544	1.687
0.52	0.893	0.919	0.945	0.971	0.997	1.023	1.050	1.076	1.103	1.131	1.159	1.187	1.217	1.248	1.280	1.314	1.351	1.500	1.643
0.53	0.850	0.876	0.902	0.928	0.954	0.980	1.007	1.033	1.060	1.088	1.116	1.144	1.174	1.205	1.237	1.271	1.308	1.457	1.600
0.54	0.809	0.835	0.861	0.887	0.913	0.939	0.966	0.992	1.019	1.047	1.075	1.103	1.133	1.164	1.196	1.230	1.267	1.416	1.559
0.55	0.769	0.795	0.821	0.847	0.873	0.899	0.926	0.952	0.979	1.007	1.035	1.063	1.093	1.124	1.156	1.190	1.227	1.376	1.519
0.56	0.730	0.756	0.782	0.808	0.834	0.860	0.887	0.913	0.940	0.968	0.996	1.024	1.054	1.085	1.117	1.151	1.188	1.337	1.480
0.57	0.692	0.718	0.744	0.770	0.796	0.822	0.849	0.875	0.902	0.930	0.958	0.986	1.016	1.047	1.079	1.113	1.150	1.299	1.480
0.58	0.655	0.681	0.707	0.733	0.759	0.785	0.812	0.838	0.865	0.893	0.921	0.949	0.979	1.010	1.042	1.076	1.113	1.262	1.405
0.59	0.619	0.645	0.671	0.697	0.723	0.749	0.776	0.802	0.829	0.857	0.885	0.913	0.943	0.974	1.006	1.040	1.077	1.226	1.369
0.60	0.583	0.609	0.635	0.661	0.687	0.713	0.740	0.766	0.793	0.821	0.849	0.877	0.907	0.938	0.970	1.004	1.041	1.190	1.333
0.61	0.549	0.575	0.601	0.627	0.653	0.679	0.706	0.732	0.759	0.787	0.815	0.843	0.873	0.904	0.936	0.970	1.007	1.156	1.299
0.62	0.516	0.542	0.568	0.594	0.620	0.646	0.673	0.699	0.726	0.754	0.782	0.810	0.840	0.871	0.903	0.937	0.974	1.123	1.266
0.63	0.483	0.509	0.535	0.561	0.587	0.613	0.640	0.666	0.693	0.721	0.749	0.777	0.807	0.838	0.870	0.904	0.941	1.090	1.233
0.64	0.451	0.474	0.503	0.529	0.555	0.581	0.608	0.634	0.661	0.689	0.717	0.745	0.775	0.806	0.838	0.872	0.909	1.068	1.201
0.65	0.419	0.445	0.471	0.497	0.523	0.549	0.576	0.602	0.629	0.657	0.685	0.713	0.743	0.774	0.806	0.840	0.877	1.026	1.169
0.66	0.388	0.414	0.440	0.466	0.492	0.518	0.545	0.571	0.598	0.626	0.654	0.682	0.712	0.743	0.775	0.809	0.846	0.995	1.138
0.67	0.358	0.384	0.410	0.436	0.462	0.488	0.515	0.541	0.568	0.596	0.624	0.652	0.682	0.713	0.745	0.779	0.816	0.965	1.108
0.68	0.328	0.354	0.380	0.406	0.432	0.458	0.485	0.511	0.538	0.566	0.594	0.622	0.652	0.683	0.715	0.749	0.786	0.935	1.078
0.69	0.299	0.325	0.351	0.377	0.403	0.429	0.456	0.482	0.509	0.537	0.565	0.593	0.623	0.654	0.686	0.720	0.757	0.906	1.049
0.70	0.270	0.296	0.322	0.348	0.374	0.400	0.427	0.453	0.480	0.508	0.536	0.564	0.594	0.625	0.657	0.691	0.728	0.877	1.020
0.71	0.242	0.268	0.294	0.320	0.346	0.372	0.399	0.425	0.452	0.480	0.508	0.536	0.566	0.597	0.629	0.663	0.700	0.849	0.992
0.72	0.214	0.240	0.266	0.292	0.318	0.344	0.371	0.397	0.424	0.452	0.480	0.508	0.538	0.569	0.601	0.635	0.672	0.821	0.964
0.73	0.186	0.212	0.238	0.264	0.290	0.316	0.343	0.369	0.396	0.424	0.452	0.480	0.510	0.541	0.573	0.607	0.644	0.793	0.936
0.74	0.159	0.185	0.211	0.237	0.263	0.289	0.316	0.342	0.369	0.397	0.425	0.453	0.483	0.514	0.546	0.580	0.617	0.766	0.909
0.75	0.132	0.158	0.184	0.210	0.236	0.262	0.289	0.315	0.342	0.370	0.398	0.426	0.456	0.487	0.519	0.553	0.590	0.739	0.882
0.76	0.105	0.131	0.157	0.183	0.209	0.235	0.262	0.288	0.315	0.343	0.371	0.399	0.429	0.460	0.492	0.526	0.563	0.712	0.855
0.77	0.790	0.105	0.131	0.157	0.183	0.209	0.236	0.262	0.289	0.317	0.345	0.373	0.403	0.434	0.466	0.500	0.537	0.685	0.829
0.78	0.052	0.078	0.104	0.130	0.156	0.182	0.209	0.235	0.262	0.290	0.318	0.346	0.376	0.407	0.439	0.473	0.510	0.659	0.802
0.79	0.026	0.052	0.078	0.104	0.130	0.156	0.183	0.209	0.236	0.264	0.292	0.320	0.350	0.381	0.413	0.447	0.484	0.633	0.776
0.80	0.000	0.026	0.052	0.078	0.104	0.130	0.157	0.183	0.210	0.238	0.266	0.294	0.324	0.355	0.387	0.421	0.458	0.609	0.750
0.81		0.000	0.026	0.052	0.078	0.104	0.131	0.157	0.184	0.212	0.240	0.268	0.298	0.329	0.361	0.395	0.432	0.581	0.724
0.82			0.000	0.026	0.052	0.078	0.105	0.131	0.158	0.186	0.214	0.242	0.272	0.303	0.335	0.369	0.406	0.555	0.698
0.83				0.000	0.026	0.052	0.079	0.105	0.132	0.160	0.188	0.216	0.246	0.277	0.309	0.343	0.380	0.529	0.672
0.84					0.000	0.026	0.053	0.079	0.106	0.134	0.162	0.190	0.220	0.251	0.283	0.317	0.354	0.503	0.646
0.85						0.000	0.027	0.053	0.080	0.108	0.136	0.164	0.194	0.225	0.257	0.291	0.328	0.477	0.620
0.86							0.000	0.026	0.053	0.081	0.109	0.137	0.167	0.198	0.230	0.264	0.301	0.450	0.593
0.87								0.000	0.027	0.055	0.083	0.111	0.141	0.172	0.204	0.238	0.275	0.424	0.567
0.88									0.000	0.028	0.056	0.084	0.114	0.145	0.177	0.211	0.248	0.397	0.540
0.89										0.000	0.028	0.056	0.086	0.117	0.149	0.183	0.220	0.369	0.512
0.90											0.000	0.028	0.058	0.089	0.121	0.155	0.192	0.341	0.484
0.91												0.000	0.030	0.061	0.093	0.127	0.164	0.313	0.456
0.92													0.000	0.031	0.063	0.097	0.134	0.283	0.426
0.93														0.000	0.032	0.066	0.103	0.252	0.395
0.94															0.000	0.034	0.071	0.220	0.363
0.95																0.000	0.037	0.186	0.329
0.96																	0.000	0.149	0.292
0.97																		0.108	0.251
0.98																		0.060	0.203
0.99																		0.000	0.143
																			0.000

Instructions: 1. Find the present power factor in column. 2. Read across to optimum power factor column. 3. Multiply that number by kW demand.
Example: If your plant consumed 410 kW, was currently operating at 73% power factor and you wanted to correct power factor to be 95% you would.
1. Find 0.73 in column. 2. Read across to 0.95 column. 3. Multiply 0.607 by 410 = 249 (round to 250.) 4. You need 250 kVAR to bring your plant to 95% power factor If you don't know the existing power factor level of your plant, you will have to calculate it before using this table. To calculate existing power factor: kW divided by kVA = power factor.

Benefits of Power Factor Correction

The cost-effectiveness of power factor correction depends upon such variables as utility power factor penalties, the need for additional system capacity, energy and demand cost, hours of facility operation, distribution system wire sizes, and the distance between the motor and the electrical meter.[9-10] As shown in the following examples, it is critical to understand your utility's rate structure to assess the benefits or reduction in utility billing due to power factor correction.[9-1, 9-9]

Secondary Benefits of Power Factor Correction

Excessive line currents due to low power factors cause excessive in-plant distribution system voltage drops and increased resistance losses. Operating motor-driven equipment under low-voltage conditions results in decreased efficiency, motor overheating, and diminished motor life. By adding power factor correction capacitors, you can restore operating voltage to proper design conditions.

When located at motor loads, power factor correction capacitors increase system current-carrying capacity, reduce voltage drops, and decrease distribution system resistance (I^2R) losses.[9-1] Increasing the power factor from 75% to 95% results in a 21% lower current in the conductors serving the same kW load. By adding power factor correction capacitors at motor loads, you can increase the total kW loading served by the conductors without increasing line currents, wire size, transformer size, or facility kVA charges. By including power factor correction capacitors in new construction or facility expansions, you can reduce project costs through decreasing the sizes of transformers, cables, busses, and switches.[9-1] In practice, however, current or ampacity ratings are a function of full-load equipment values; therefore, size reductions may be precluded by electrical codes.

Utility Rate Schedule

In this scenario, the utility charges according to kW demand ($4.50/kW) and includes a surcharge or adjustment for low power factor. The following formula shows a billing adjustment based upon a desired 95% power factor.

Plant Conditions

For our sample facility, the original demand is 4,600 kVA × 0.80, or 3,680 kW.

The multiplier applies to power factors up to 0.95.

$$kW_{BILLED} = kW_{DEMAND} \times \frac{0.95}{PF}$$

Where:

kW_{BILLED}	=	Adjusted or billable demand
kW_{DEMAND}	=	Measured electric demand in kW
PF	=	Power factor as a decimal

Billing Before Power Factor Correction	Billing After Power Factor Corrected to 95%
$\frac{3{,}680 \text{ kW} \times 0.95}{0.80}$	$\frac{3{,}680 \text{ kW} \times 0.95}{0.95}$
= 4,370 × $4.50	= 3,680 × $4.50
= $19,665/month or $235,980/year	= $16,560/month or $198,720/year

Savings are $37,260/year.

Example 9-2

Utility Rate Schedule

The utility measures and bills based upon total current used (working plus reactive current) at $3.50/kVA demand.

Plant Conditions

Assume a constant 4,600 kVA demand with an 80% power factor. Correct to 95% power factor.

Billing Before Power Factor Correction	Billing After Power Factor Corrected to 95%
4,600 kVA × $3.50 = $16,000/month	$kW_{DEMAND} = kVA_{DEMAND\ 1} \times PF_1$ $= 4{,}600 \times 0.8 = 3{,}680$ $kW_{DEMAND\ 2} = \frac{kW_{DEMAND}}{PF_2}$ $kW_{DEMAND\ 2} = \frac{3{,}680}{0.95} = 3{,}873$ **Where:** $kVA_{DEMAND\ 1}$ = kVA demand before PF correction $kVA_{DEMAND\ 2}$ = kVA demand after PF correction kW_{DEMAND} = Electric demand in kW PF_1 = Original power factor PF_2 = Power factor after correction **Corrected Billing:** **3.873 kVA × $3.50 = $13,555/month**

Savings are ($16,100–$13,555) × 12 months = $30,540/year.

Up to $61,000 could be spent on power factor correction equipment if plant management would support a 2-year simple payback on investment.

Example 9-3

Poor power factor contributes to power losses in the in-plant distribution system. Calculate the power loss by squaring the line current and multiplying by the circuit resistance (I^2R). Generally, distribution system losses are small and are related to the cable length and inverse of the cross sectional area—a typical industrial plant will suffer only a 2% loss in the cables if they are loaded to full capacity.[9-8] Reductions in losses (upstream of the power factor correction capacitor locations) are calculated by the relationship shown in Equation 9-2.[9-1]

The *Industrial Electrical Distribution Systems Guidebook* contains worksheets for calculating the benefits of correcting both individual motor and total plant power factor.[9-14]

$$\%\ \text{reduction} = 100 - 100 \times \left(\frac{PF_1}{PF_2}\right)^2$$

Where:

% reduction = Percent reduction in distribution losses

PF_1 = Original power factor

PF_2 = Power factor after correction

Equation 9-2. Reduction in distribution system losses due to power factor correction at the motor or motor control center

Helpful Tip

Beware of sales representatives claiming that their product will “reduce motor energy costs by up to 35%,” as benefits of “black boxes” are often greatly exaggerated.[9-12] In reality, the product may reduce in-plant distribution system *line losses* by up to 35% (and only for the conductor serving an individual motor) or reduce the power supplied to an unloaded motor by up to 35%. Saving a large percentage of a small amount of energy or power may not result in significant or cost-effective dollar savings.[9-13]

Power Factor Correction Costs

The average cost for capacitors on a 480-volt system is about \$30 to \$40 per kVAR (not including installation costs). Automatic power factor controllers or capacitors with harmonic filters cost more. These features are typically associated with capacitors exceeding 100 kVAR. A single large capacitor bank has a lower installed cost than multiple small installations scattered throughout the plant. The cost per kVAR for small capacitors on individual motors is substantially higher because of labor and materials costs. The cost of large banks is lower on a per-kVAR basis because of economies of scale. The installed cost per kVAR of capacitance is also lower at higher voltages. At medium voltage levels (2400 volts and up), unit costs are generally about \$3 to \$6 per kVAR.

Assume that installing a power factor correction capacitor at a motor improves power factor from 85% to 95%. Losses are reduced by:

Loss Reduction =
$100 - 100 \times (85/95)^2$ or 19.9%

Remember that this is 19.9% of the losses only on the conductor used to serve the motor load. Also note that line losses are proportional to voltage drop. A drop from 480 volts at the transformer tap to 470 volts at the motor indicates a distribution system loss of $(10/480) \times 100 = 2.0\%$. Multiplying the loss reduction times the total distribution system losses gives a total energy savings of approximately 0.4% of the energy going down the conductor to serve the motor load.

Example 9-4

Quick Fact

Short-circuit megavolt amperes (MVAs) represents system impedance. It is the current (in millions of amperes) that would be drawn by a short circuit, multiplied by the no-load voltage of the system at the point of interest. In reality, circuit protectors would blow before short-circuit current could stabilize, so it is defined by linearly extrapolating the volts-per-amp system voltage drop, at moderate load, down to zero system volts.

Avoiding Harmonic Resonances When Installing Capacitors

Industrial plants that install and operate capacitors must pay careful attention to the creation of steady-state harmonic resonances.[9-8] Equation 9-3 can be used to calculate the resonant frequency created with a capacitor and system inductance. As shown in the equation, the square root of the short-circuit MVA divided by the capacitor megavolt ampere reactive (MVAR) indicates the resultant harmonic for the system under study.[9-15]

$$h_f = \sqrt{\frac{MVA_{SHORT\ CIRCUIT}}{MVAR_{CAPACITOR}}}$$

Equation 9-3

If the resonant frequency is near an odd harmonic, consider reducing capacitor MVAR to bring the system out of tune with that harmonic. This is particularly important if you have a known source of these harmonics. For example, variable frequency drives can be a significant source of 5th and 7th harmonics.

Resonant conditions near the 3rd, 5th, 7th, 11th, and 13th harmonics are usually the most troublesome.[9-15] Harmonics cause additional noise on the line and generate heat. This heat can cause failure of capacitors or transformers. Consult with your capacitor supplier or a specialist in harmonic mitigation. Many vendors offer harmonic analysis services and will help you to properly select and install power factor correction equipment.

Consider a case in which a 1,200 kVAR capacitor to be installed on a 12.47 kV system at a location where the three-phase short-circuit is 2800 amps (A).

$$MVA_{SHORT\ CIRCUIT} = 2800\ A \times 12.47\ kV \times \frac{\sqrt{3}}{1{,}000{,}000} = 60.5$$

$$MVAR_{CAPACITOR} = 1200\ kVAR/1000 = 1.2\ MVAR, \text{ and } h_f = \sqrt{\frac{60.5}{1.2}} = 7.1$$

Example 9-5

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APPENDICES

Appendix A: Motor Nameplate and Field Test Data Form

Employee Name ______________________

Company ______________________

Date ______________________

Facility/Location ______________________

Department ______________________

Process ______________________

General Data

Serving Electrical Utility ______________________

Energy Rate ($/kWh) ______________________

Monthly Demand Charge ($/kW/mo) ______________________

Application ______________________

Type of equipment that motor drives

Coupling Type ______________________

Motor Type (Design A, B, C, D, AC, DC etc.) ______________________

Motor Purchase Date/Age ______________________

Rewound ☐ Yes ☐ No

Motor Nameplate Data

1. Manufacturer ______________________
2. Motor ID Number ______________________
3. Model ______________________
4. Serial Number ______________________
5. NEMA Design Type ______________________
6. Size (hp) ______________________
7. Enclosure Type ______________________
8. Synchronous Speed (RPM) ______________________
9. Full Load Speed (RPM) ______________________
10. Voltage Rating ______________________
11. Frame Designation ______________________
12. Full Load Amperage ______________________
13. Full Load Power Factor (%) ______________________
14. Full Load Efficiency (%) ______________________
15. Service Factor Rating ______________________
16. Temperature Rise ______________________
17. Insulation Class ______________________
18. kVA Code ______________________

Motor Operating Profile

	Weekdays	________	Wknd/Holiday	________
	Days/Year	________	Days/Year	________
Hours Per Day	1st Shift	________		________
	2nd Shift	________		________
	3rd Shift	________		________

Annual Operating Time ________ hours/year

Type of load (Place an "X" by the most appropriate type)

_______ 1. Load is quite steady, motor "On" during shift

_______ 2. Load starts, stops, but is constant when "On"

_______ 3. Load starts, stops, and fluctuates when "On"

Answer the following only if #2 or #3 above was selected:

% of time load is "on" ________%

Answer the following only if #3 was selected:

Estimate average load as a % of motor size ________%

Measured Data

Supply Voltage

By Voltmeter

Line-to-Line-

V_{ab} ________

V_{bc} ________ V_{avg} ________

V_{ca} ________

Input Amps

By Ampmeter

A_a ________

A_b ________ A_{avg} ________

A_c ________

Power Factor (PF, %) ______________________

Input Power (kW) ______________________

If available. Otherwise equal to:
$V_{avg} \times A_{avg} \times (PF/100) \times \sqrt{3}/1000$

Motor Operating Speed (RPM) ______________________
By Tachometer

Driven Equipment Operating Speed (RPM) ______________________

Appendix B: Average Efficiencies for Standard Efficiency Motors at Various Load Points

Efficiencies for 900 RPM, Old Standard Efficiency Motors								
Motor Size	Load Level In Percent							
	ODP				TEFC			
	100%	75%	50%	25%	100%	75%	50%	25%
10	85.3	86.1	84.8	78.3	85.5	85.8	84.8	77.3
15	86.3	87.5	86.6	79.6	86.4	87.2	86.4	79.0
20	87.6	88.3	87.3	81.8	87.9	88.9	88.2	84.4
25	88.3	88.8	88.1	83.0	87.9	88.4	86.8	78.6
30	88.1	89.1	88.5	84.5	88.6	89.2	88.6	85.2
40	87.5	87.6	87.1	84.5	89.0	88.8	87.0	82.5
50	89.3	90.2	89.6	87.1	89.8	89.7	88.5	82.5
60	89.9	90.5	89.9	86.4	90.6	91.1	90.3	86.9
75	90.9	91.4	90.8	85.8	90.6	90.8	89.9	83.6
100	91.3	91.7	91.2	86.8	91.1	91.6	91.0	88.0
125	91.6	92.1	91.6	89.5	91.5	91.4	90.5	87.5
150	91.9	92.6	92.2	89.7	91.5	91.7	91.0	88.0
200	92.6	93.5	93.1	90.2	93.0	93.8	93.1	90.1
250	93.6	94.4	94.2	92.7	94.2	94.5	94.4	91.5
300	94.1	92.4	89.5	86.0	94.2	94.5	94.4	91.5

Efficiencies for 1,200 RPM, Old Standard Efficiency Motors								
Motor Size	Load Level In Percent							
	ODP				TEFC			
	100%	75%	50%	25%	100%	75%	50%	25%
10	87.4	87.9	86.5	79.3	84.9	85.9	84.4	80.0
15	87.0	87.4	86.3	79.6	87.0	87.2	86.0	79.7
20	87.7	88.6	88.3	85.1	87.7	88.8	88.2	83.6
25	89.0	89.5	88.8	85.2	88.9	89.5	88.5	81.3
30	89.5	90.2	89.7	87.6	89.6	90.3	89.0	83.8
40	89.4	89.9	89.2	85.2	89.9	90.4	88.6	84.5
50	89.7	89.2	87.8	71.7	90.6	91.2	90.5	86.0
60	90.8	91.5	90.9	87.5	90.8	91.0	90.2	83.1
75	91.5	91.7	91.8	88.9	91.6	91.6	90.7	86.5
100	92.0	92.5	92.1	88.3	92.1	92.1	91.9	84.5
125	92.0	92.5	92.1	88.3	92.1	92.1	91.9	86.0
150	92.6	93.1	92.6	90.0	93.1	93.3	92.6	90.8
200	92.9	93.1	91.7	89.9	92.6	93.2	92.5	88.4
250	94.1	94.2	93.3	92.7	94.4	94.4	93.9	90.0
300	94.4	94.6	94.5	92.8	94.4	94.4	93.8	91.0

Efficiencies for 1,800 RPM, Old Standard Efficiency Motors								
Motor Size	Load Level In Percent							
	ODP				TEFC			
	100%	75%	50%	25%	100%	75%	50%	25%
10	86.1	87.4	86.9	81.8	85.7	86.7	85.4	77.4
15	87.8	88.8	88.3	82.0	86.6	87.5	86.0	74.9
20	88.3	89.4	88.7	83.3	88.5	89.3	88.5	82.9
25	88.9	90.0	89.8	86.6	89.3	89.9	88.8	82.1
30	88.9	90.6	90.5	87.4	89.6	90.2	89.2	83.6
40	90.0	90.3	89.4	85.7	90.2	90.4	89.2	81.6
50	90.7	91.2	90.4	87.4	91.3	91.6	90.9	84.1
60	91.3	91.7	90.8	86.8	91.8	91.9	90.8	85.2
75	91.9	92.3	91.6	87.7	91.7	92.0	90.9	85.1
100	92.1	92.7	92.2	89.2	92.3	92.2	91.2	86.2
125	92.2	92.8	92.2	88.2	92.2	91.6	90.5	84.0
150	92.8	93.1	92.4	88.6	93.0	92.8	91.5	86.3
200	93.0	93.4	93.0	90.3	93.5	93.3	92.0	86.3
250	94.4	94.6	93.8	92.0	94.2	94.1	93.0	88.8
300	94.6	94.7	93.8	92.8	94.4	94.2	93.1	89.9

Efficiencies for 3,600 RPM, Old Standard Efficiency Motors								
Motor Size	Load Level In Percent							
	ODP				TEFC			
	100%	75%	50%	25%	100%	75%	50%	25%
10	85.0	86.1	85.0	78.7	85.0	84.7	82.7	74.1
15	86.6	87.7	86.8	80.5	85.7	85.8	83.6	73.2
20	88.1	88.9	88.8	85.4	86.6	87.7	86.1	76.7
25	88.4	89.2	88.7	83.7	87.5	87.4	85.3	75.2
30	87.7	88.9	88.8	84.7	87.7	87.0	84.7	75.4
40	88.6	89.7	899	86.9	88.5	88.0	85.8	75.2
50	89.1	90.1	89.8	88.4	89.0	88.7	86.7	77.8
60	90.4	90.9	90.9	87.8	89.4	88.4	85.8	76.6
75	90.4	90.6	90.1	85.7	90.6	89.9	88.0	78.9
100	90.5	91.2	91.0	89.0	90.9	90.3	88.7	81.9
125	91.2	91.9	91.4	90.3	90.9	90.1	87.9	77.4
150	91.7	91.8	91.9	90.1	91.5	90.9	88.4	81.7
200	91.5	91.7	90.9	83.6	92.7	92.0	90.1	83.5
250	93.0	93.0	92.8	87.4	94.7	94.7	93.8	91.0
300	93.9	94.3	93.5	90.6	94.7	94.4	93.5	89.8

Appendix C: Motor Energy Savings Calculation Form

Employee Name ______________________________

Company ______________________________

Date ______________________________

Facility/Location ______________________________

Department ______________________________

Process ______________________________

Motor Nameplate and Operating Information

Manufacturer ______________________________

Motor ID Number ______________________________

Size (hp) ______________________________

Enclosure Type ______________________________

Synchronous Speed (RPM) ______________________________

Full Load Speed (RPM) ______________________________

Full Load Amperage ______________________________

Full Load Power Factor (%) ______________________________

Full Load Efficiency (%) ______________________________

Utility Rates

Energy Rate ($/kWh) ______________________________

Monthly Demand Charge ($/kW/mo.) ______________________________

Annual Operating Hours (hrs./yr.) ______________________________

Annual Energy Use and Cost

Input Power (kW) ______________________________

Annual Energy Use ______________________________

Input Power × Annual Operating hours

Annual Energy Cost ______________________________

Annual Energy Use × Energy Rate

Annual Demand Cost ______________________________

Input Power × Monthly Demand Charge × 12

Total Annual Cost ______________________________

Annual Energy Cost + Annual Demand Cost

Motor Load and Efficiency Determination

Load ______________________________

Input Power (kW) / [Motor Size (hp) × 0.746/Efficiency at Full Load]

Motor Efficiency at Operating Load ______________________________

(Interpolate from Appendix B)

Energy Savings and Value

kW saved ______________________________

Input Power − [Load × hp × 0.746/Efficiency of Replacement Motor at Load Point]

kWh saved ______________________________

kW saved × Annual Operating Hours

Total Annual Savings

Total Annual Savings $______________________________

(kW saved × 12 × Monthly Demand Charge) + (kWh saved x Energy Rate)

Cost for Replacement Motor ______________________________

(or Incremental Cost for New Motor)

Simple Payback (years) ______________________________

(Cost for Replacement Motor + Installation Charge − Utility Rebate) / Total Annual Savings

Appendix D: Motor Repair versus Replace Breakpoint Worksheet

This worksheet will assist you to determine the repair versus replace breakpoint for NEMA Design A and B motors in your facility. In-service standard efficiency motors below the breakpoint horsepower value should be replaced with a NEMA Premium Efficiency motor when they fail. The old standard efficiency motor is then scrapped. Motors above the breakpoint horsepower value should be repaired in accordance with model repair guidelines that reflect repair best practices and then returned to service.

Information necessary to determine the horsepower breakpoint includes the plant's investment or simple payback criteria, typical motor annual operating hours, utility incentive electrical rates ($/kWh, $/kW/mo), motor load (typically 70%), motor repair cost, expected efficiency loss due to repair, and the cost of the premium efficiency replacement motor. Fill in the table below with repair cost quotes and new premium efficiency motor costs that are obtained from your local repair shop and motor distributor.

What is the annual operating hours for motors in your plant?____

What is the typical load on your in-service motors? ____________ % ________________________________

What is your plant's simple payback criteria? _____________ years ________________________________

Motor Breakpoint Horsepower Evaluation						
Motor hp	Standard Motor Efficiency	Premium Motor Cost	Premium Motor Efficiency	Energy Savings kWh/yr	Dollar Savings $/year	Simple Payback, years
15						
20						
25						
30						
40						
50						
60						
75						
100						
125						
150						
200						
250						

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