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3

Economic Aspects of Buildings

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3.1 Central and Distributed Utilities

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Electricity is the primary energy source for operating much of the HVAC equipment in buildings including fans, chillers, pumps, and electrical auxiliaries. It is also the primary energy source for lighting in the U.S. Given the importance of electricity and the current rapid evolution of the electrical industry in the U.S., it is important for the HVAC designer to understand both present and future options for electricity generation.

This chapter discusses the expected near-term situation in traditional generation and distribution industries and a new paradigm, the generation of electricity using many, small distributed generators. Distributed generation (sometimes called distributed resources — DR) is expected to grow rapidly in the first decade of the 21st century to the extent that by 2010, up to 20% of new generation capacity in the U.S. will be from DR.

This section reviews the status and likely future application of competing electrical generation technologies, particularly those with near-term potential. Capacity additions in the United States in the next 10 years will be based on gas, coal, and to some extent on renewables. Repowering of older plants will likely be increasingly attractive.

Gas turbine-based plants will dominate in the immediate future. The most advanced combustion turbines achieve more than 40% efficiency in simple cycle mode and greater than 50% lower heating value (LHV) efficiency in combined cycle mode (gas turbine plus steam turbine). In addition, combustion turbine/combined cycle (CT/CC) plants offer siting flexibility, phased construction, and capital costs between \$400/kW and \$800/kW. These advantages, coupled with adequate natural gas supplies and the assurance of coal gasification backup, make this technology a prime choice for green field and repowered plants.

There is also good reason why the pulverized coal plant may still be a primary choice for many generation companies. Scrubbers have proved to be more reliable and effective than early plants indicated. Up to 99% SO_2 removal efficiency is possible. About 60 GW of U.S. coal-fired generation is currently equipped with flue gas desulfurization (FGD) systems. Also, the pulverized-coal (PC) plant has the capability for much improved heat rate (about 8500 Btu/kWh) even with full flue gas desulfurization.

Atmospheric and pressurized fluidized bed combustion (FBC) offer reductions in both SO_2 and NO_x and also permit the efficient combustion of low rank fuels. In the U.S., there are now over 150 operating units for power generation and ten vendors of FBC boilers, four of which offer units up to 250 MW in size.

Gasification power plants exist at the 100 MW and 160 MW levels and are planned up to 450 MW. Much of the impetus is now coming from the DOE clean coal program, where three gasification projects are in progress.

In small unit sizes, often suitable for distributed generation, technical progress will be made (although large-scale applications still remain modest) in renewables (solar, wind, biomass), microturbines and fuel cells. They promise high efficiencies, low emissions, and compact plants.

Capital cost and efficiency will remain the determining issues in the application of all these possible generation options.

Overall Industry Needs

The U.S. electric power industry consists of a network of small and large companies, both private and public — more than 3000 in all. They generate more than 700 GW of electric power — by far the greatest concentration of electric power production in the world, about equal to the next five countries combined. However, although advanced generation technologies are beginning to find their way into the power industry, most installed capacity is 20 or more years old and equipment efficiency reflects this vintage. Likewise, the transmission and distribution system is aging.

The National Energy Strategy of 1991 set general U.S. policy for the future, and one specific directive was to enhance the efficiency of generation, transmission, and use of electricity. There are two key drivers for this directive: one is to reduce emissions of undesired air, water, and ground pollutants, and the other is to conserve our fossil fuels. The desire to move to a more energy-conscious mode of operation will clearly give impetus to the renewables as significant (although probably not major) future power sources and will encourage efficiency advances in both fossil and nuclear plants.

The CRC *Handbook of Energy Efficiency* (Chapter 7) summarizes the fuel supply outlook through 2010.

3.1.1 Management of Existing Fossil Plant Assets

Generation companies are now looking at power plants in a more profit-focused manner, treating them as company assets, to be invested in a way that maximizes the company bottom line or the profit for the company. As the average age of fossil unit inches upward, executives are often asking "If I invest a dollar into this plant to improve heat rate, availability, or some other plant performance measure, will this produce more in base profit to my company than investing, say, in some other plant, or building new capacity, or buying power from outside?" One important aspect of this new business strategy concerns the "use" that is being made of any particular plant, since increased plant usage implies more company value for that plant.

Here are some measures of plant utilization:

Heat rate is the quantifiable measure of how efficiently we can convert fuel into MW. It is inherently limited by cycle and equipment design and by how we operate the plant. In a simple condensing cycle the heat rate of a fossil fuel plant cannot fall much below 8500 Btu/kWh, even with super-critical cycles and double reheat of the feedwater.

Capacity factor (CF) is a measure that indicates how a plant is loaded over the year. Few single cycle fossil units achieve 90% capacity factor these days, and this has an impact on the measured heat rate of the unit. Under ideal conditions for effective asset management, and apart from downtime for maintenance, CF should be close to 100% for the purposes of getting the most out of the plant asset. Market conditions and the reserve margins of the utility often dictate otherwise.

Price of electricity is a determining factor in how units are dispatched. Electricity cost is largely dictated by fuel cost, which typically makes up 70% of the cost of operating a power plant. It is interesting that none of the top ten U.S. units in heat rate makes the top ten in electricity cost.

Finally, some have suggested a term called overall *energy efficiency*, which describes how well a plant utilizes the basic feedstock (coal, oil, or gas). If we can produce other products from a fossil plant besides electricity, the value of that asset goes up, and, of course, the "effective" heat rate drops significantly.

Using these measures we are seeing many, perhaps most, of the major U.S. generation companies take a close look at their plant assets to judge their bottom-line value to the company. In the growing competitive generation business, an upgrade or maintenance investment in a power plant will be determined largely by the return on investment the company can expect at the corporate level. In order to achieve these corporate goals, it is necessary to have a good handle on equipment life and the probability of failures. Also needed are options for improving heat rate, for increasing output (by repowering), and for improving plant productivity to make the assets competitive.

3.1.2 Clean Coal Technology Development

At an increasing rate in the last few years, innovations have been developed and tested aimed at reducing emissions through improved combustion and environmental control in the near term, and in the longer term by fundamental changes in how coal is preprocessed before converting its chemical energy to electricity. Such technologies are referred to as clean coal technologies — described by a family of precombustion, combustion/conversion, and postcombustion technologies. They are designed to provide the coal user with added technical capabilities and flexibility and at lower net cost than current environmental control options. They can be categorized as follows:

- **Precombustion**, in which sulfur and other impurities are removed from the fuel before it is burned.
- **Combustion**, in which techniques to prevent pollutant emissions are applied in the boiler while the coal burns.
- **Postcombustion**, in which the flue gas released from the boiler is treated to reduce its content of pollutants.
- **Conversion**, in which coal, rather than being burned, is changed into a gas or liquid that can be cleaned and used as a fuel.

Coal Cleaning

Cleaning of coal to remove sulfur and ash is well established in the United States with more than 400 operating plants, mostly at the mine. Coal cleaning removes primarily pyritic sulfur (up to 70% SO_2 reduction is possible) and in the process increases the heating value of the coal, typically by about 10% but occasionally by 30% or higher. Additionally, if slagging is a limiting item, increased MW may be possible, as at one station which increased generation from 730 MW to 779 MW. The removal of organic sulfur, chemically part of the coal matrix, is more difficult but may be possible using microorganisms or through chemical methods, and research is underway. Finally, heavy metal trace elements can be removed also, conventional cleaning removing (typically) 30 to 80% of arsenic, mercury, lead, nickel, and antimony.

Pulverized-Coal-Fired Plants

Built in 1959, Eddystone 1 at PECO Energy was, and still is, the supercritical power plant with the highest steam conditions in the world. Main steam pressure was 5000 psi when built, and steam temperature 1200°F for this double reheat machine. PECO Energy will continue to operate Eddystone I to the year 2010, an impressive achievement for a prototype unit.

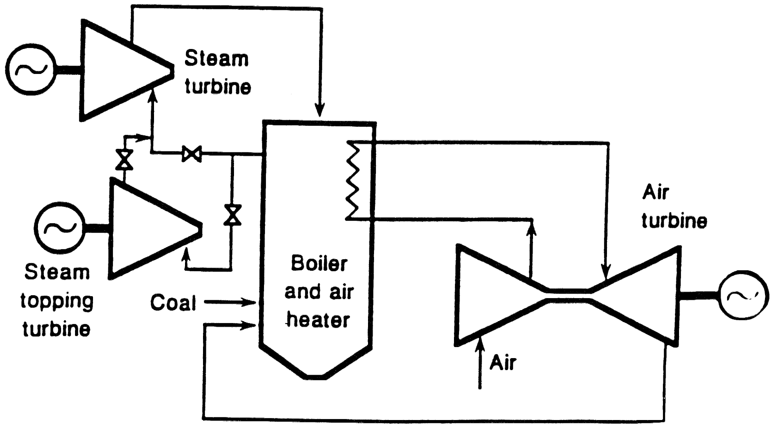


FIGURE 3.1.1 A pulverized-coal combined cycle with topping steam turbine has a projected heat rate of 7200 Btu/kWh. The air turbine uses 1800°F air, or 2300°F air with supplemental firing. The topping turbine uses steam at 1300°F.

But the most efficient pulverized-coal-fired plant of the future is likely to be a combined cycle plant, perhaps with a topping steam turbine, as shown in Figure 3.1.1. With an 1800°F air turbine and 1300°F topping steam turbine, the heat rate of this cycle is about 7200 Btu/kWh — very competitive with any other proposed advanced cycles in the near term.

3.1.3 Emissions Control

Worldwide about 40% of electricity is generated from coal. Installed coal-fired generating capacity, more than 1000 GW, is largely made up of 340 GW in North America, 220 GW in Western Europe, Japan, and Australia, 250 GW in Eastern Europe and the former USSR, and 200 GW in China and India. In the decade to the year 2000, about 190 GW of new coal-fired capacity was added. The control of particulates, sulfur dioxides, and nitrogen oxides from those plants is one of the most pressing needs of today and of the future. This is accentuated when the impact of carbon dioxide emissions, with its contribution to global warming, is considered. To combat these concerns, a worldwide move toward environmental retrofitting of older fossil-fired power plants is underway, focused largely on sulfur dioxide scrubbers and combustion or postcombustion optimization for nitrogen oxides.

Sulfur Dioxide Removal

When it is a matter of retrofitting an existing power plant, no two situations are identical: fuels, boiler configurations, and even space available for new pollution control equipment all play a role in the decision on how a utility will meet new emission reduction requirements. For example, a decision to install a sorbent injection technology rather than flue gas desulfurization (FGD) for SO_2 reduction may depend not only on the percentage reduction required but also on the space constraints of the site and on the capacity factor of the plant (with a lower capacity factor, the lower capital cost of sorbent injection is advantageous compared to FGD). Most utilities, though, have been selecting either wet or dry scrubbing systems for desulfurization. Generically these can be described as in the following sections.

Conventional Lime/Limestone Wet Scrubber. By 1994 the United States already had more than 280 flue gas desulfurization (FGD) systems in operation on 95,000 MW at utility stations; now the U.S. experience is approaching 1000 unit years.

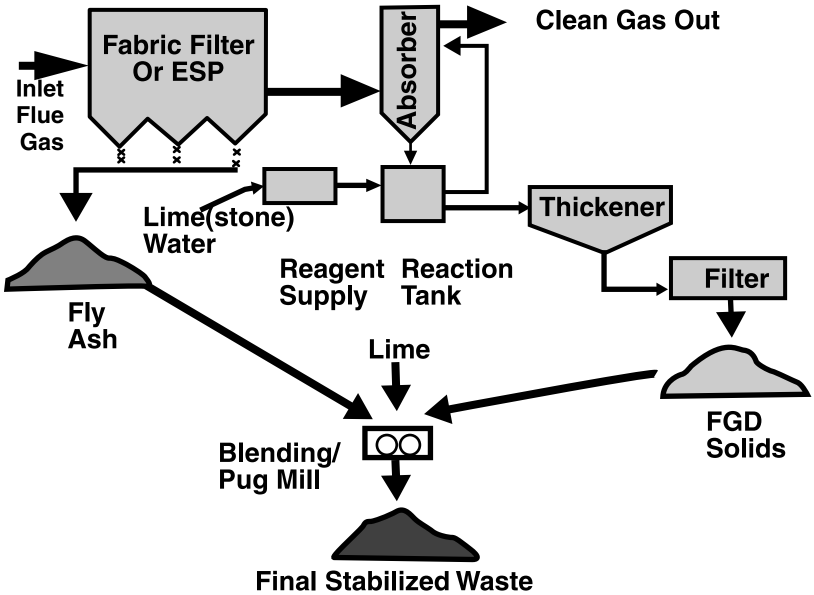


FIGURE 3.1.2 The conventional lime/limestone wet scrubber is the dominant system.

The dominant system is the wet limestone design, limestone being one-quarter the cost of lime as a reagent. In this system (Figure 3.1.2) the limestone is ground and mixed with water in a reagent preparation area. It is then conveyed to a spray tower called an absorber, as a slurry of 90% water and 10% solids, and sprayed into the flue gas stream. The SO_2 in the flue gas is absorbed in the slurry and collected in a reaction tank, where it combines with the limestone to produce water and calcium sulfate or calcium sulfate crystals. A portion of the slurry is then pumped to a thickener where these solids/crystals settle out before going to a filter for final dewatering. Mist eliminators installed in the system ductwork at the spray tower outlet collect slurry/moisture entrained in the flue gas stream. Calcium sulfate is typically mixed with fly ash (1:1) and lime (5%) and disposed of in a landfill.

Various improvements can be made to this basic process, including the use of additives for performance enhancement and the use of a hydrocyclone for dewatering, replacing the thickener, and leading to a salable gypsum byproduct. The Chiyoda-121 process (Figure 3.1.3) reverses the classical spray scrubber and bubbles the gas through the liquid. This eliminates the need for spray pumps, nozzle headers, separate oxidation towers, and thickeners. Bechtel has licensed this process in the U.S.; the first commercial installation is at the University of Illinois on a heating boiler, and a DOE clean coal demonstration is underway. The waste can be sold as gypsum or disposed of in a gypsum stack.

Spray Drying. Spray drying (Figure 3.1.4) is the most advanced form of dry SO_2 control technology. Such systems tend to be less expensive than wet FGD but typically remove a smaller percentage of the sulfur (90% compared with 98%). They are used when burning low-sulfur coals and utilize fabric filters for particle collection, although recent tests have shown applicability to high-sulfur coals also.

Spray driers use a calcium oxide reagent (quicklime), which, when mixed with water, produces a calcium hydroxide slurry. This slurry is injected into the spray drier, where it is dried by the hot flue gas. As the drying occurs, the slurry reacts to collect SO_2. The dry product is collected at the bottom of the spray tower and in the downstream particulate removal device, where further SO_2 removal may take place. It may then be recycled to the spray drier to improve SO_2 removal and alkali utilization.

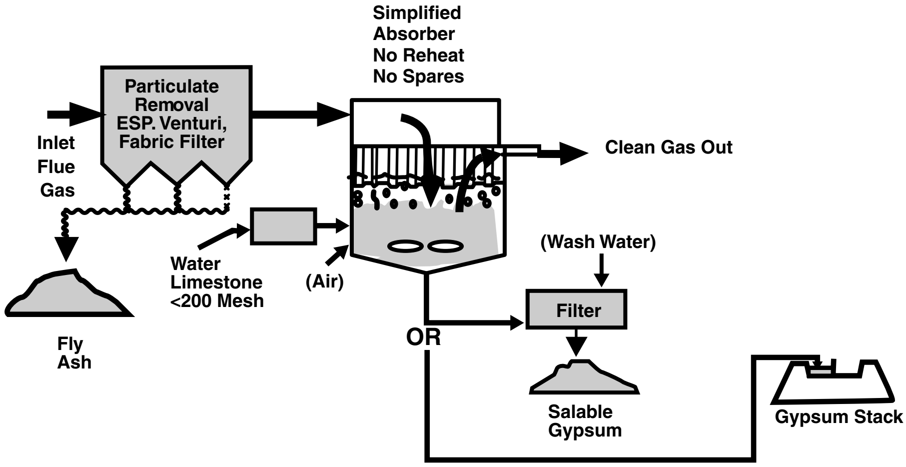


FIGURE 3.1.3 The Chiyoda-121 scrubber simplifies the process by bubbling the flue gas through the liquid, eliminating some equipment needs.

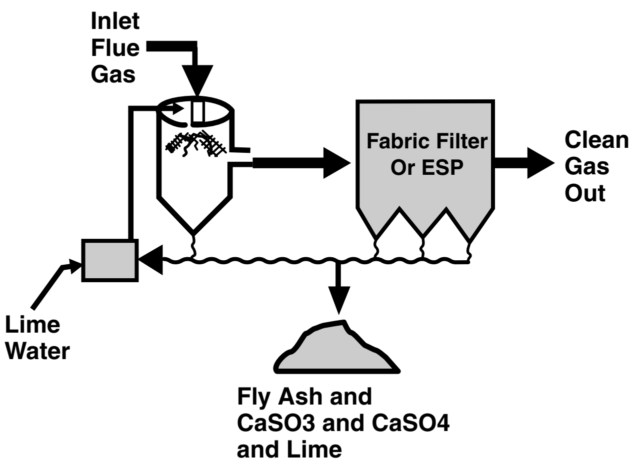


FIGURE 3.1.4 Spray driers use a calcium oxide reagent mixed with water, which is dried by the flue gas. A dry product is collected in a fabric filter.

For small, older power plants with existing electrostatic precipitators (ESPs), the most cost-effective retrofit spray dry configuration locates the spray dryer and fabric filter downstream of the ESP, separating in this manner the spray dryer and fly ash waste streams. The fly ash can then be sold commercially.

Control of Nitrogen Oxides

Nitrogen oxides can be removed either during or after coal combustion. The least expensive option and the one generating the most attention in the U.S. is combustion control, first through adjustment of the fuel/air mixture, and second through combustion hardware modifications. Postcombustion processes seek to convert NO_x to nitrogen and water vapor through reactions with amines such as ammonia and urea. Selective catalytic reduction (SCR) injects ammonia in the presence of a catalyst for greater effectiveness. So the options (Figure 3.1.5) can be summarized as

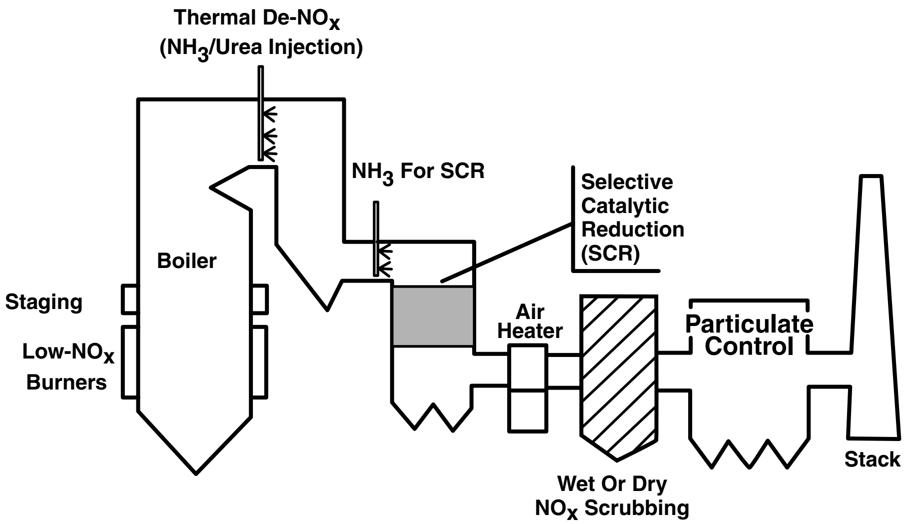


FIGURE 3.1.5 Control options for NO_x include operational, hardware, and postcombustion modifications.

Operational changes. Reduced excess air, and biased firing, including taking burners out of service.
Hardware combustion modifications. Low NO_x burners, air staging, and fuel staging (reburning).
Postcombustion modifications. Injection of ammonia or urea into the convection pass, selective catalytic reduction (SCR), and wet or dry NO_x scrubbing (usually together with SO_2 scrubbing).

Low NO_x burners can reduce NO_x by 50%, and SCR by 80%, but the low NO_x burner option is much more cost-effective in terms of cost per ton of NO_x removed. Reburning is intermediate in cost per removed ton and can reduce NO_x by 50%, or 75% in conjunction with low NO_x burners.

Fluidized-Bed Plants. Atmospheric fluidized-bed boilers (see Figure 3.1.6) offer reductions in both SO_2 and NO_x and also permit the efficient combustion of low-rank fuels. In the U.S. there are now over 150 operating units generating over 5000 MW, and ten vendors of FBC boilers, four of which offer units up to 250 MW in size. The rapid growth in number of FBC units and capacity is shown in Figure 3.1.7.

The future for fluidized-bed utility boilers is evident in the move by several countries (Sweden, Japan, Spain, Germany, United States) toward the pressurized fluidized-bed combined cycle design. The modular aspect of the PFBC unit is a particularly attractive feature leading to short construction cycles and low-cost power. This was particularly evident in the construction of the Tidd plant, which first generated power from this combined cycle (Figure 3.1.8) on November 29, 1990.

3.1.4 Combustion Turbine Plants

Combustion turbine-based plants comprise the fastest growing technology in power generation. Between now and 2005, natural gas-fired combustion turbines and combined cycles burning gas will account for 50 to 70% of new generation to be ordered worldwide. GE forecasts that combustion turbines and combined cycles will account for 45% of new orders globally, and for 66% of new U.S. orders. Almost all of these CT and CC plants will be gas-fired, leading a major expansion of gas for electricity generation.

Estimates suggested 23 GW of new gas-fired CT capacity in the United States between 1990 and 2000 (Figure 3.1.9). Worldwide there are even more striking examples. In the United Kingdom, 100% of all new generation ordered or under construction is gas-fired combined cycle.

Aircraft Technology

In the 1960s, gas turbines derived from military jet engines formed a major source of utility peaking generation capacity. Fan-jets, though, which replaced straight turbojets, were much more difficult and

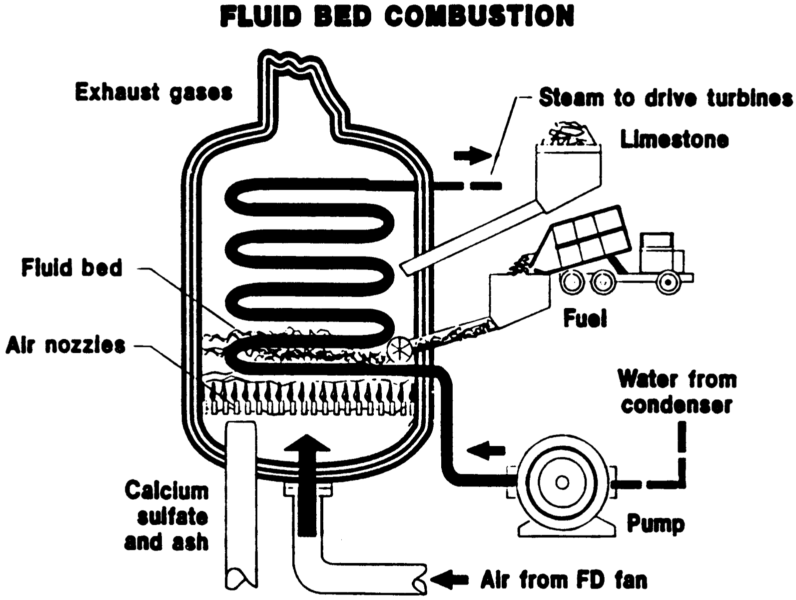


FIGURE 3.1.6 The addition of limestone or Dolomite to the combustion chamber allows the coal limestone mixture to be burned in a suspended bed, fluidized by an underbed air supply. The sulfur in the coal reacts with the calcium to produce a solid waste of calcium sulfate. The combustion temperature is low (1500°F), reducing NO_x emissions.

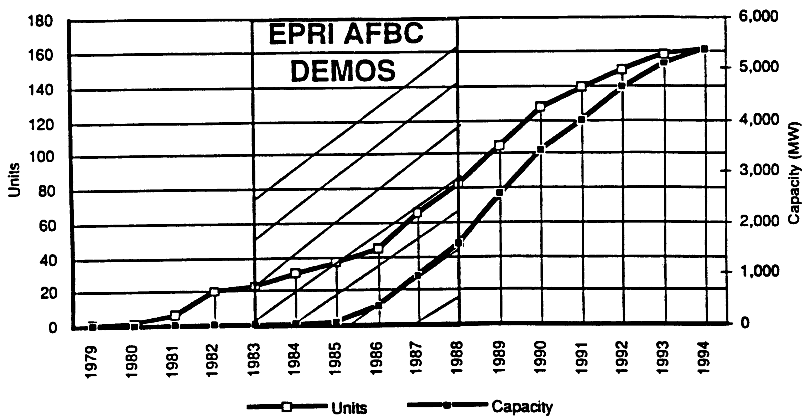


FIGURE 3.1.7 The growth in number and size of AFBC plants has been significant since the demonstration of 100+ MW sizes in U.S. utility plants.

expensive to convert to utility use, and the resulting aeroderivative turbines have been little used. The main reason for the high cost was the need to replace the fan and add a separate power turbine.

As bypass ratios, and hence fan power, have increased, the most recent airline fan-jets can be converted to utility service without adding a separate power turbine. Furthermore, modifications of these engines, with intercooling and possibly reheat, appear to be useful for advanced power cycles such as chemical recuperation and the humid air turbine.

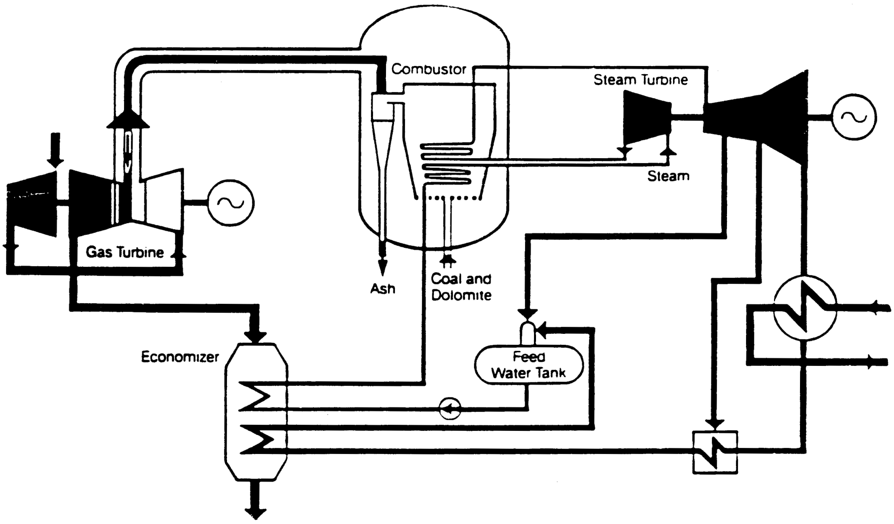


FIGURE 3.1.8 Pressurized, fluidized-bed combustor with combined cycle. This 70 MW system operated at the Tidd plant of American Electric Power.

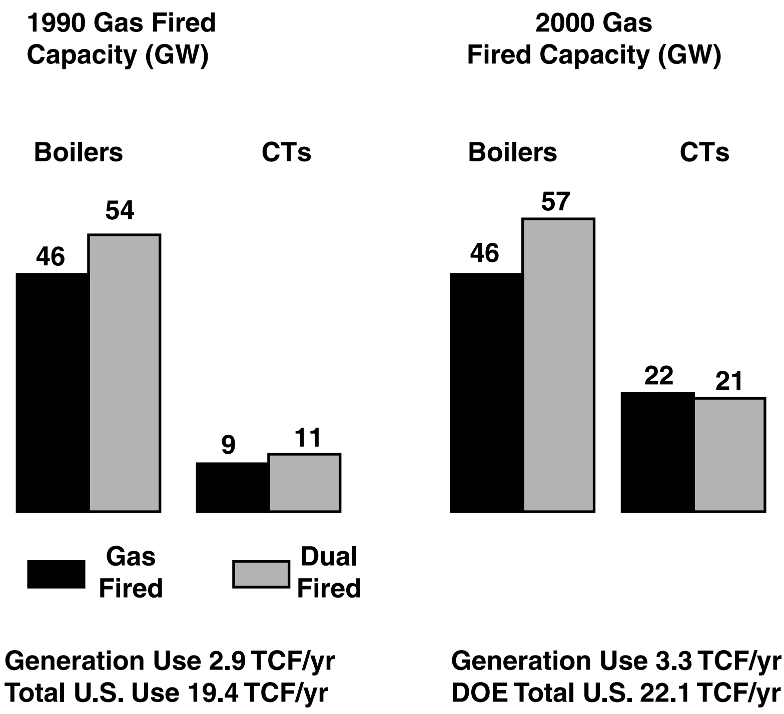


FIGURE 3.1.9 Combustion turbine additions in the United States in the decade before the year 2000. (From GRI/DOE [1991], NERC [1990].)

Humidified Air Power Plants

A new class of combustion turbine-based approaches are termed humidified air power plants. In these combustion turbine cycles the compressor exit air is highly humidified prior to combustion. This reduces the mass of dry air needed and the energy required to compress it.

The continuous plant cycle for this concept is termed the Humid Air Turbine (HAT). This cycle using, for example, extensive modification of the TPM FT4000, has been calculated to have a heat rate on natural gas about 5% better than the latest high-technology combined cycle. The HAT cycle is adaptable to coal gasification leading to the low emissions and high efficiency characteristics of gasification combined cycle plants but at a low capital cost, since the steam turbine bottoming cycle is eliminated.

Gasification Plants

One option of particular importance is that of coal gasification (Figure 3.1.10). After the EPRI Coolwater demonstration in 1984 at the 100 MW level, the technology has moved ahead in the U.S. largely through demonstrations under the CCT program. Overseas, the 250 MW Buggenham plant in Holland was operational in 1994, and the PSI/Destec 265 MW and TECO 260 MW clean coal demos both operated in 1996. Beyond this, there is a 300 MW plant for Endesa, Spain and a 330 MW unit for RWE in Germany (Figure 3.1.11).

Gasification-based plants have among the lowest emissions of pollutants of any central station fossil technology. With the efficiency advantages of combined cycles, CO_2 emissions are also lower. Fuel flexibility is an additional benefit, since the gasifier can accommodate a wide range of coals, plus petroleum coke. Integrated gasification combined cycle (IGCC) plants permit a hedge against long-term increases in natural gas prices. Natural gas-fired combustion turbines can be installed initially, and gasifiers at a later time when a switch to coal becomes prudent.

Concurrent with the advances in gasification are efficiency improvements in combustion turbines. The new F-type CTs operate at 2300°F, and 2500°F machines are likely soon. This makes the IGCC a very competitive future option.

A Look at the Future of Combustion Turbines

Combustion turbines and combined cycles grew steadily more important in all generation regimes; peaking, mid-range, and base load. They account for the majority of new generation ordered and installed. If the present 2300°F firing temperature machines operate reliably and durably, CT and CC plants will begin to retire older steam plants and uneconomic nuclear plants. With no clear rival other than fuel cells, which are only now emerging, CT technology may dominate fossil generation, and new advanced CT cycles — with intercooling, reheat, possibly chemical recuperation, and most likely humidification — should result in higher efficiencies and lower capital costs. Integrated gasification, which guarantees a secure bridge to coal in the near term, will come into its own as gas prices rise under demand pressure. By 2015, coal through gasification is expected to be the economic fuel for a significant fraction of new base-load CT/CC generation. The rate at which these trends develop depends in a large measure on the relative costs by burning gas or coal.

3.1.5 Distributed Electrical Generation Basics

A confluence of events in the U.S. electrical generation and transmission industry has produced a new paradigm for distributed electrical generation and distribution in the U.S. Electrical deregulation, reluctance of traditional utilities to commit capital to large central plants and transmission lines, and a suite of new, efficient generation hardware have all combined to bring this about. Persistent environmental concerns have further stimulated several new approaches. This section describes the term *distributed generation technologies* and their differentiating characteristics along with their readiness for the U.S. market. In order to decide which approaches are well suited to a specific project, an assessment methodology is needed. A technically sound approach is therefore described and example results are given in the final section of this chapter.

Distributed resource generation (DR) is any small scale electrical power generation technology that provides electric power at a site closer to customers than central station generation, and that is usually interconnected to the distribution system or directly to the customer's facilities. According to the Distributed Power Coalition of America (DPCA), research indicates that distributed power has the

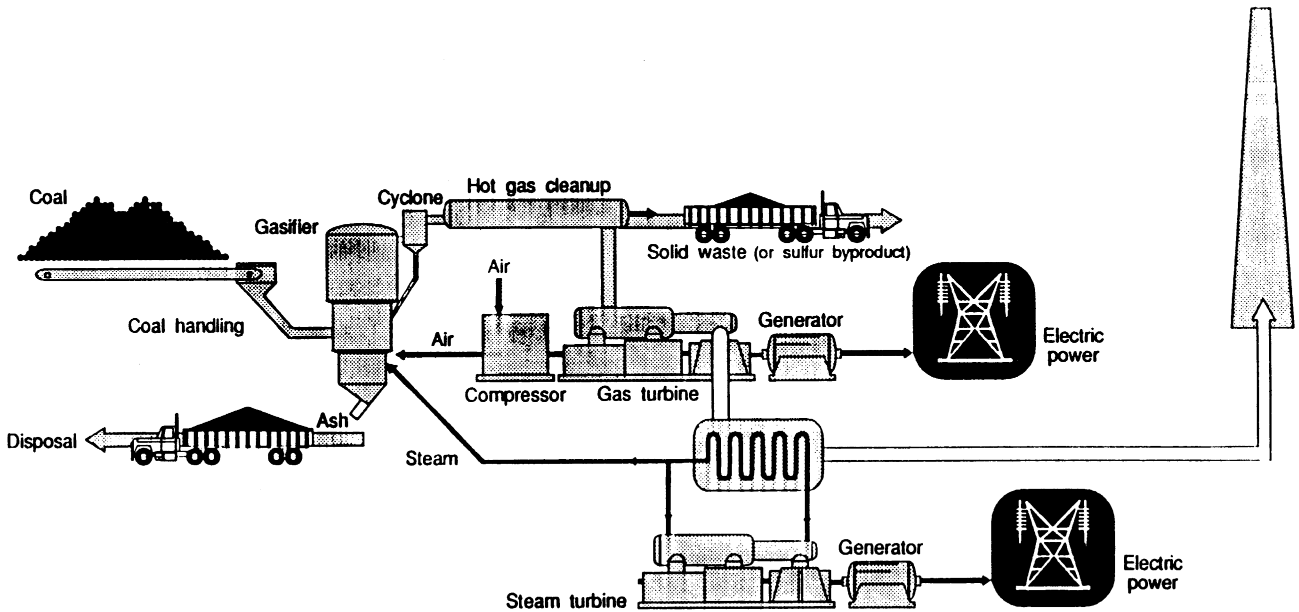


FIGURE 3.1.10 Gasification combined cycle.

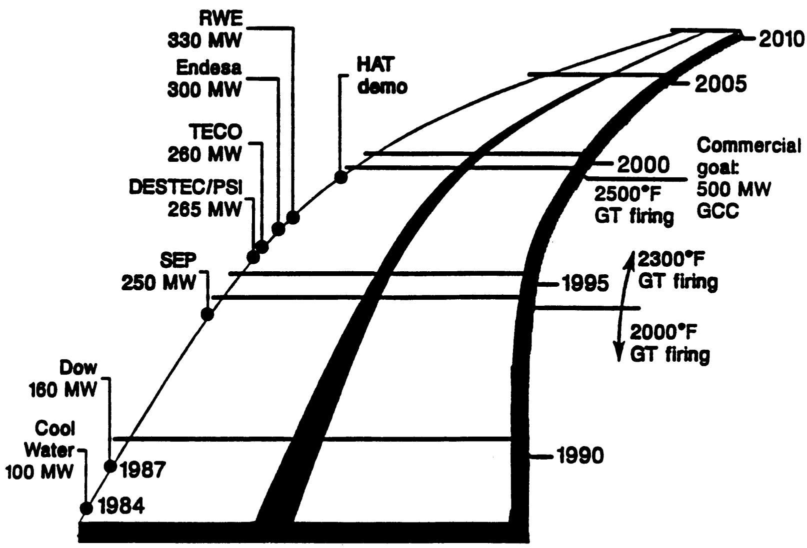


FIGURE 3.1.11 Gasification power plant time line.

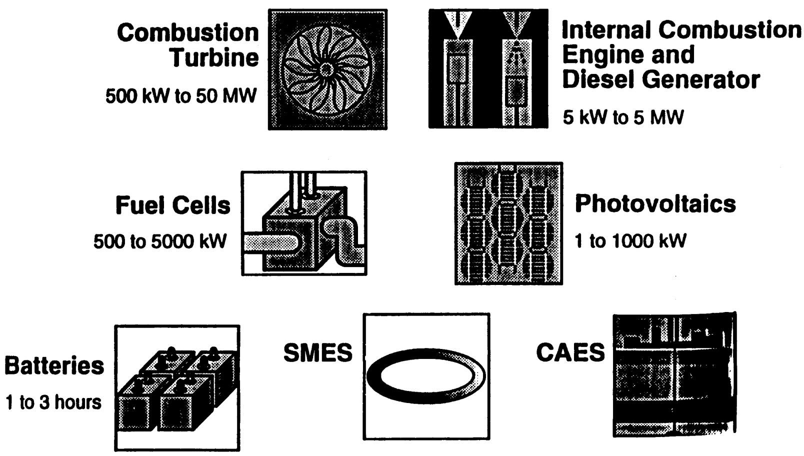


FIGURE 3.1.12 Distributed generation and energy storage technologies.

potential to capture about 20 percent of additions to generating capacity, or 35 gigawatts (GW), over the next two decades. The Electric Power Research Institute estimates that the DR market could amount to 2.5–5 GW/year by 2010. DR technologies include small combustion turbine generators, internal combustion reciprocating engines and generators, photovoltaic panels, and fuel cells.* Other technologies including solar thermal conversion, stirling engines, and biomass conversion are considered as DR. We arbitrarily limit the term DR, in this chapter, to refer to plants with capacities less than a few MW.

* Wind power is not included since, in the U.S., it has been primarily deployed as a central power generation technology.

TABLE 3.1.1 Cost Projections for Representative Generation Technologies for a Plant in the Northeast United States

Plants	Pulverized Coal Plants: Subcritical Wet Scrubber 300 MW	Pulverized Coal Plants: Supercritical Wet Scrubber 400 MW	Atmospheric FBC Circulating No Scrubber 200 MW	Pressurized FBC Combined Cycle 340 MW
Capital cost (1993)[a] ($/kW)	1607	1600	1805	1318
Nonfuel O&M costs				
Variable (mills/kWh)	3.0	2.8	5.4	1.8
Fixed ($/kW yr)	46.6	43.1	37.0	37.6
Efficiency (%)	36.0	39.0	35.0	41.0

Plants	Coal Gasification Combined Cycle 500 MW	Coal Gasification Humid Air Turbine 500 MW	Coal Gasification Molten Carbonate Fuel Cell 400 MW	Gas-Fired Combined Cycle 225 MW
Capital cost (1993) ($/kW)	1648	1447	2082	595
Nonfuel O&M costs				
Variable (mills/kWh)	0.5	1.3	1.1	0.4
Fixed ($/kW yr)	49.9	40.4	57.2	26.5
Efficiency (%)	42.0	42.0	50.0	46.0

[a] Costs of new plants are likely to reduce, in real terms, over the next 10 years due to technology developments and increased worldwide competition for markets in the developing countries. New technologies (PFBC, IGCC, fuel cells) will lower capital costs as production capacity grows.

Source: Technical Assessment Guide, EPRI TR-102275-V1R7, June 1993. Electrical Power Research Institute, Palo Alto, CA.

Distributed generation can provide a multitude of services to both utilities and consumers, including standby generation, peak shaving capability, baseload generation, or cogeneration. Less well understood benefits including ancillary services — VAR support, voltage support, and network stability among others — may ultimately be of more economic benefit than simple energy-related benefits.

DR technologies can have environmental benefits ranging from truly green power (photovoltaics) to significant mitigation of one or more pollutants often associated with coal-fired generation. Natural gas-fired DR turbine generators, for example, release less than a quarter of the emissions of SO_2, less than 1/100th NO_X, and 40 percent less CO_2 than many new coal-boiler power plants; these DR units are clean enough to be situated among residential and commercial establishments (DCPA, 1998).

Electric restructuring has spurred the consideration of DR power because the buyers and sellers of electricity will have to be more responsive to market forces. Central utilities suffer from the burden of significant stranded costs. DR avoids this cost. DR is a priority in parts of the country where the spinning reserve margins are shrinking, where growing industrial and commercial uses as well as transmission and distribution (T&D) constraints are limiting power flows (DCPA, 1998).

Additional impetus was added to DR efforts during the summers of 1998, 1999, and 2000 by the heat waves that staggered the U.S. and caused power cuts in the west and across the Rust Belt. The shortages and outages were the result of a combination of factors — climbing electricity demand, permanent or temporary shutdown of some of the region's nuclear facilities, unusually hot weather, and 1998 summer tornadoes that downed a transmission line (McGinley, 1998).

Forces Propelling DR Today

The DR era appears to have arrived based on evidence from many and diverse sources. U.S. utility deregulation is an "enabler" for widespread DR adoption but is not a required condition of rapid growth in small generation sales. Experts list the following reasons for expected DR applications in the next 20 years:

- Utilities are seeking ways to avoid large capital investments in new generating capacities. Incremental investments in smaller plants are preferred.
- Distribution system loading is near the limit with the result that power quality is suffering and power outages are becoming more prevalent. DR of power bypasses most of the distribution system.
- Several small and efficient DR technologies are nearing maturity.
- Telecommunication and computational systems compatible with the widespread deployment of DR will exist in the very near future.
- U.S. utilities are being restructured as a result of deregulation of electrical utilities.
- DR owned by local building operators or energy service companies avoid the electricity price volatility seen in the past two years during peak load periods.

In spite of these notable reasons for DR growth, it must be recognized that DR is a "disruptive technology," and, as was the case with past technologies, it may offer worse economic or technical performance than traditional approaches. However, as commercialization continues, these new technologies will be characterized by rapid performance improvements and larger market share. Because the small scale technologies described next tend to be simpler and smaller than older ones, they may well be less expensive to own and operate.

TABLE 3.1.2 Summary of Distributed Generation Technologies

Criterion	IC Engine	Microturbine	PVs	Fuel Cells
Dispatchability	Yes	Yes	No	Yes
Capacity range	50 kW–5MW	25 kW–25 MW	1 kW–1 MW	200 kW–2 MW
Efficiency[a]	35%	29–42%	6–19%	40–57%
Capital cost ($/kW)	200–350	750–1000	6600	3750–5700
O&M cost[b] ($/kWh)	0.01	0.005–0.0065	0.001–0.004	0.0017
NO_X (lb/Btu) — Nat. gas	0.3	0.10	n/a	0.003–0.02
NO_X (lb/Btu) — Oil	3.7	0.17	n/a	n/a
Technology status	Commercial	Commercial in larger sizes	Commercial	Commercial scale demos

[a] Efficiencies of fossil and renewable DR technologies are not directly comparable. The method described later in this book includes all effects needed to assess energy production.

[b] O&M costs do not include fuel. Capital costs have been adjusted based on quotes.

Source: From DCPA, 1998.

The Technologies

Table 3.1.2 provides an overview of feasible, present or near term DR technologies. Each listed technology is summarized below in alphabetical order.

Fuel Cells

A fuel cell is a device in which hydrogen and oxygen combine without combustion to produce electricity in the presence of a catalyst. One design is shown in Figure 3.1.13. Several competing technologies have been demonstrated and are listed below with their nominal operating temperatures.

- Phosphoric acid (PA) — 300°F
- Proton exchange membrane (PEM) — 200°F
- Molten carbonate (MC) — 1200°F
- Solid oxide (SO) — 1300°F

As indicated in Table 3.1.2, the costs of fuel cells are too high to be competitive now, but industry experts have indicated that prices should fall because of mass production. Where environmental regulations are strict, fuel cells offer the only truly clean solution to electricity production outside of the renewables sector.

The key barriers to fuel cell usage include

- Cost — predicted cost reductions have not materialized; in fact, one large firm recently announced a 60% price increase.
- Hydrogen fuel — widespread adoption will require a new fuel distribution infrastructure in the U.S. or on-site reforming of natural gas (methane).
- Maintenance costs are uncertain.
- Transient response to building load variations is unacceptable for load following for some technologies.

Contrasting these barriers are some very attractive FC features:

- The only byproduct is water — NO_x emissions are very low (<1PPM).
- Efficiency is good — 50–60% (LHV basis).
- Thermal or electrical cogeneration is possible in buildings.
- Modularity is excellent — nearly any building-related load can be matched well (kW to MW range).

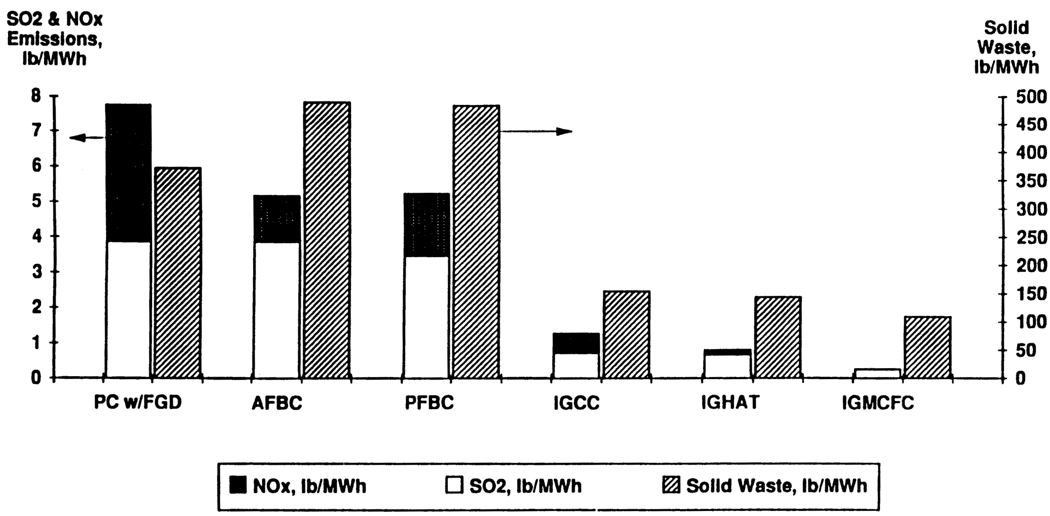


FIGURE 3.1.13 Emissions and solid waste from coal-based technologies are lowest with the gasification plants. IGCC (Integrated Gasification Combined Cycle), IGHAT (Integrated Gasification Humid Air Turbine), and IGMCFC (Integrated Gasification Molten Carbonate Fuel Cell).

Internal Combustion Engines

Reciprocating internal combustion engines (ICEs) are the traditional technology for emergency power around the world. Operating experience with Diesel and Otto cycle units is extensive. The cost of units is the least of any DR technology, but maintenance costs are among the greatest. Furthermore, diesel and gasoline engines produce unacceptable emission levels in air quality nonattainment areas of the U.S.

Natural gas (NG) ICE generators offer a partial solution to the emissions problem but do not solve it entirely. However, the NG-fired ICE is the key competition to all DR technologies considered here.

The key barriers to ICE usage include

- Maintenance cost — the highest among the DR technologies due to the large number of moving parts.
- NO_x emissions are highest among the DR technologies (15–20 PPM even for lean burn designs).
- Noise is low frequency and more difficult to control than for other technologies; adequate attenuation is possible.

Attractive ICE features include

- Capital cost is lowest of the DR approaches.
- Efficiency is good — 32–36% (LHV basis).
- Thermal or electrical cogeneration is possible in buildings.
- Modularity is excellent — nearly any building-related load can be matched well (kW to MW range).
- Part load efficiency is good (the need for this is described later).

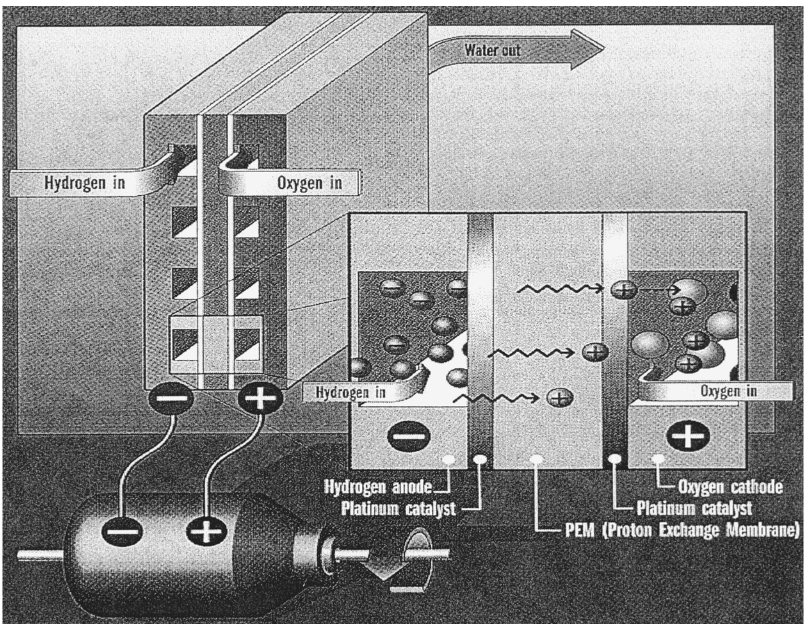


FIGURE 3.1.14 PEM fuel cell schematic diagram.

Microturbines

A microturbine (MT) is a Brayton cycle engine using atmospheric air and natural gas fuel to produce shaft power. Figure 3.1.15 shows the essential components of this device. Although a dual shaft approach is shown in the figure, a single-shaft design is also used in which the power produced in the expander is supplied to both the compressor and the load by a single shaft. The dual shaft design offers better control but at the cost of another rotating part and two more high speed bearings. Electrical power is produced by a permanent magnet generator attached to the output shaft or to a gear reducer driven by the output shaft.

Figure 3.1.16 is a photograph of a small microturbine showing most of the key components except for the recuperator. The recuperator is used in most units because about half of the heat supplied to the working fluid can be transferred from the exhaust gas to the combustion air. Without a recuperator, the overall efficiency of an MT is 15–17% whereas with an 85% effective recuperator the efficiency can be as high as 33%. MTs without recuperators are basically burners that produce a small amount of electricity with thermal output to be used for cogeneration.

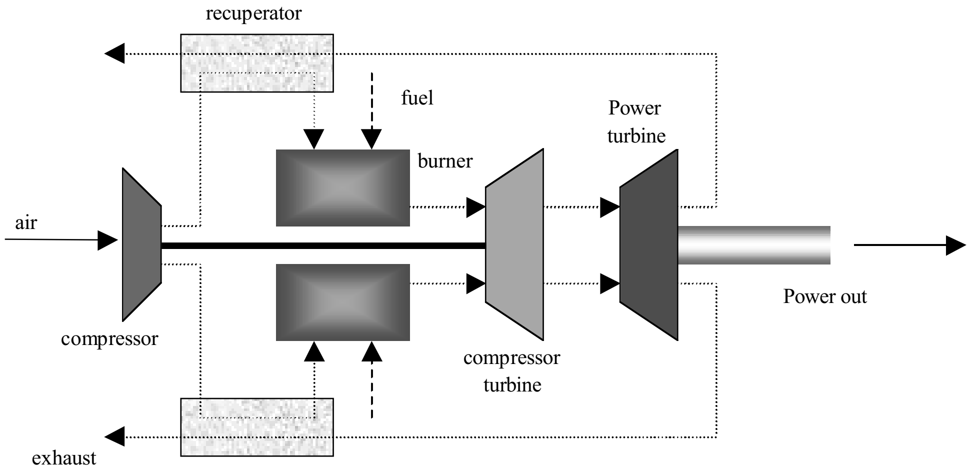


FIGURE 3.1.15 Schematic diagram of dual shaft microturbine design.

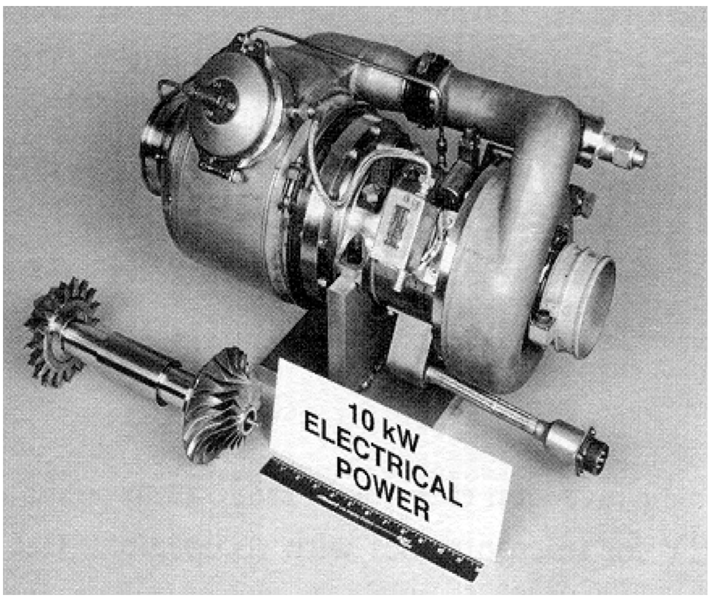


FIGURE 3.1.16 10-kW microturbine (courtesy of Honeywell International Inc.).

A handful of MT manufacturers have announced products in the U.S. Sizes range from 25 kW to 150 kW with double digit power ratings being the most common. As of December 2000, fewer than 1000 MTs had been shipped to U.S. locations.

Attractive MT features include

- Capital cost is low.
- Efficiency is good — 30–33% (LHV basis).
- Emissions are modest (<10 PPM NO_x is quoted by manufacturers).
- Thermal or electrical* cogeneration is possible in buildings.

*Electrical cogeneration refers to the use of exhaust gases to power a bottoming turbine cycle, often an organic Rankine cycle to produce additional electric power.

FIGURE 3.1.17 Solar PV panel (courtesy of NREL; photo by W. Gretz).

- Modularity is excellent — nearly any building-related load can be matched well by multiple units of small capacity.

The key barriers to MT usage include

- Maintenance cost — unknown but expected to be lower than ICEs because of many fewer moving parts.
- Part load efficiency is questionable — manufacturer's data vary.
- Limited field experience.
- Use of air bearings is desirable to reduce maintenance, but air filtration requirements are stringent.
- High frequency noise is produced but is relatively easy to control.

Solar Photovoltaics

Photovoltaic (PV — see Figure 3.1.17) cells directly convert sufficiently energetic photons in sunlight to electricity. Because sunlight is a diffuse resource, large array areas are needed to produce significant power. However, offsetting this is the zero cost of the fuel itself. In 2000 there was a PV market worldwide of the order of 200 MW* per year.

Prices for PV arrays have dropped by at least two orders of magnitude in the past three decades, but they still appear to be too high for many applications in the U.S. where the present utility grid offers an alternative. However, in mountainous areas where the grid does not exist or in developing countries where electricity infrastructure investments may never be made, PVs can produce power more cheaply than the common ICE alternative.

Attractive features of PV systems include

- Emissions are zero.
- Fossil fuel consumption is zero.
- Low temperature thermal cogeneration (using building-integrated modules) is possible for space heating in buildings.

*The rating of solar systems on a kW or MW basis is misleading because the rating conditions are such that quoted outputs are nearly optimal. To compare solar and nonsolar energy costs, one must determine the cost of electricity for each technology as described later in this book.

- Modularity is excellent — nearly any building-related load can be matched well by multiple units of small capacity.
- Maintenance is negligible except where batteries are involved.
- Part load efficiency is excellent.

The key barriers to PV usage include

- The price of delivered power exceeds other DR resources; subsidies exist in some states that make PV-produced power competitive.
- Temporal match of power produced to load is imperfect; batteries or other systems are often needed.

Other Approaches

Although not treated in this chapter, several additional DR techniques hold promise for the future. They can be assessed using the approaches described later in this chapter. Included in this future list are stirling engines, solar stirling engines, and solar thermal conversion.

New Characteristics Common to All DR Systems

The previous section described four DR systems that appear to have significant near term feasibility. The next section describes exactly how one rationally selects the best, or best mix of, DR approaches. However, we first need to enumerate the key features that distinguish DR approaches from traditional central generation methods.

Need for New Controls Methods

Present utility power dispatch approaches cannot accommodate thousands of small, distributed generators of power and other ancillary services. Generally speaking, DR owners or their agents will operate their systems as much as possible when their marginal cost of producing power is less than the marginal cost of competing power. Legal, operating, and marketing costs for individual, small generators may also be prohibitive.

The financial dispatch of these generators requires knowledge of the following:

- Real time building loads and accurate predictions of near future loads.
- Real time cost of power controlled by the independent system operator (ISO) or its equivalent; dynamic pricing is the wave of the future.
- Dynamic power production characteristics of DR units.
- Real time cost of producing power from the available DR resources.

It appears that what will evolve to handle the dispatch problem is a new virtual power plant independent system operator which appears to the (ISO*) as a single dispatchable entity. It is the job of the VPP to determine which DR resources should be used to sell power to the grid and when. Real time knowledge of both local loads and grid-wide demand for power are required. New methods of trading and transaction processing seem to be inevitable as DR grows rapidly. By treating many small generators in the aggregate, the per unit cost of transactions and information may be reduced. To gain an appreciation of this, consider that the California ISO will not purchase ancillary services from generators less than 10 MW in size — equivalent to 200 50-kW microturbines.

Need for New Interconnection Codes and Standards

Each DR technology requires different electrical safety protocols and standards. It appears that the PV industry had made the most significant progress of the new DR systems. Numerous IEEE, ASME, and other standards bodies are involved as of the writing of this handbook.

*Also included would be the power exchange (PX) if it exists for electricity futures marketing.

3.1.6 Distributed Generation Economic Assessment

The technical and economic assessment of DR resources requires that a uniform method of assessment be used for all technologies. The methodology must include defensible estimates of

- Thermal and electrical loads on the DR system
- DR electrical production including part load effects
- Economic analysis including all reasonable and known* costs and benefits of DR.

This section summarizes a first principles approach for assessing the economic feasibility of DR systems, whether renewable or fossil-based. The same approach can be used to compare central and distributed generation sources competing in the same utility region. The context here is the U.S. energy economy. However, DR has much larger potential in the developing world where central T&D and generation do not exist. The methods described next can also be used to determine the most suitable DR technology for these markets.

Loads

It is often not possible to obtain the exact load shape for a specific building. Long-term monitoring can be costly and is usually not seen as a justifiable expense. For this reason, it is helpful to work with libraries of "standard" load shapes that can be adjusted to match the total and peak consumption of a specific building.

Once a "generic" load shape for a specified building class has been determined, the hourly values are adjusted to match the (1) actual total consumption, (2) peak demand, and (3) load factor for the selected billing period.

Economic Parameters

The proper calculation of the life cycle cost or savings of distributed generation requires a number of different economic parameters. An investment in distributed generation must have an acceptable rate of return. There are two components to the economic valuation: the first is a standard calculation based on initial costs and fuel use, and the second incorporates transmission, distribution, and other credits that vary by location and utility.

The life cycle analysis of DR is similar to other energy systems. The discount, inflation, and fuel cost escalation rates are used along with the estimated system lifetime to estimate the life cycle savings of the system. The negative cash flows (i.e., out of pocket) include the installed cost of the system, the incremental cost of gas consumed by the DR system (for IC engine, turbine, and fuel cell technologies), annual and intermittent maintenance costs, and any replacement costs. The offsetting positive cash flows include the avoided cost of electricity, the avoided cost of gas if heat recovery is used, and any tax credits and depreciation.

Utility Rates

The use of distributed generation makes sense only if

- DR power can be produced at a lower cost than the utility-supplied power
- The need for guaranteed power overrides mere power cost considerations
- The sale of power produced by a DR system results in a positive cash flow to the DR owner.

Determining the total energy bill is usually not a trivial calculation. It is easy to calculate if a real-time pricing rate is used. However, most commercial and industrial rates incorporate time-of-use components, block components, or both. These make it difficult to predict the incremental cost of the "next" kWh or therm used by the building at any arbitrary point within the billing cycle. To properly estimate the utility

*In the present work, environmental benefits are not included in the economic analysis. Once economic values can be established and agreed to, the methodology presented can accommodate them readily.

bill for a given building, the energy consumption and demand for each hour of the billing period must be known. Stranded cost recovery charges must also be included.

Ancillary benefits from installing distributed resources have traditionally been targeted at the T&D system level. For electric utilities, installing small-scale distributed generation systems in the range of 200- to 5000-kW capacity can reduce costs by avoiding transmission and distribution upgrades. In addition, they can provide more reliable service to their customers. Some of the benefits from a utility perspective include

- Reduced T&D line losses
- T&D system upgrade deferrals
- Modular generation equipment investments
- Reactive power and voltage support; other power quality improvements
- Environmental compliance benefits
- Improved system reliability
- Reduced equipment maintenance intervals

These costs and benefits are described in detail in Curtiss, Kreider, and Cohen (1999).

Environmental Considerations

Emission reductions from clean DR sources can save utilities money and provide for public benefits of cleaner air. The Clean Air Act Amendment of 1990 required lower ozone emissions in virtually all metropolitan areas by the year 2000. Just as clean technologies can benefit from environmental compliance considerations, DR technologies which exceed the limits of the environmental requirements will have to comply and therefore be in competition with other cleaner DR technologies. In some cases, the environmental permitting and regulations will add to the cost of DR technologies.

Performance Modeling

To assess accurately the economic feasibility of distributed generation at a site, a reasonably complete model should be developed that incorporates the following algorithms:

- A *weather simulation* module should provide hourly site temperatures, solar radiation, wind speed, etc.
- A *building simulation* algorithm should generate hourly building loads.
- A *DR equipment simulation* should use any site weather data from the weather simulation and the building loads to determine the portion of building electrical and thermal loads that are offset by on-site production.
- Some form of *DR control optimization* must be included in the algorithms. This can be as simple as selecting between peak shaving control or baseline support control. A smarter control approach than either of these will result in greater economic benefit to the DR hardware investor.
- A *rate analysis and calculation* algorithm will be necessary to accurately determine the utility bill based on any block and time-of-use specifications.

An Example Microturbine Assessment

The HVAC engineer is often called early in the design phase to assess the viability of various energy supplies for a project. For traditional utility suppliers, the techniques are well known and use standard building simulation tools. However, for DR assessments there are additional steps. This section, using a concrete example, illustrates the approach by summarizing results from a simple analysis using a DR screening tool. In this case study, a hospital was chosen with the load shapes as shown in Figure 3.1.18 — 450 kW of electrical capacity were added to the building as a package of 10 microturbines. The turbines were assumed to have a lifetime of 7 years and an installed cost of $750/kW. No heat recovery (i.e., cogeneration) was used in the analysis. This example illustrates the importance of control strategy and utility rate. The conclusion from the study is that local utility rates (both gas and electric) must be used

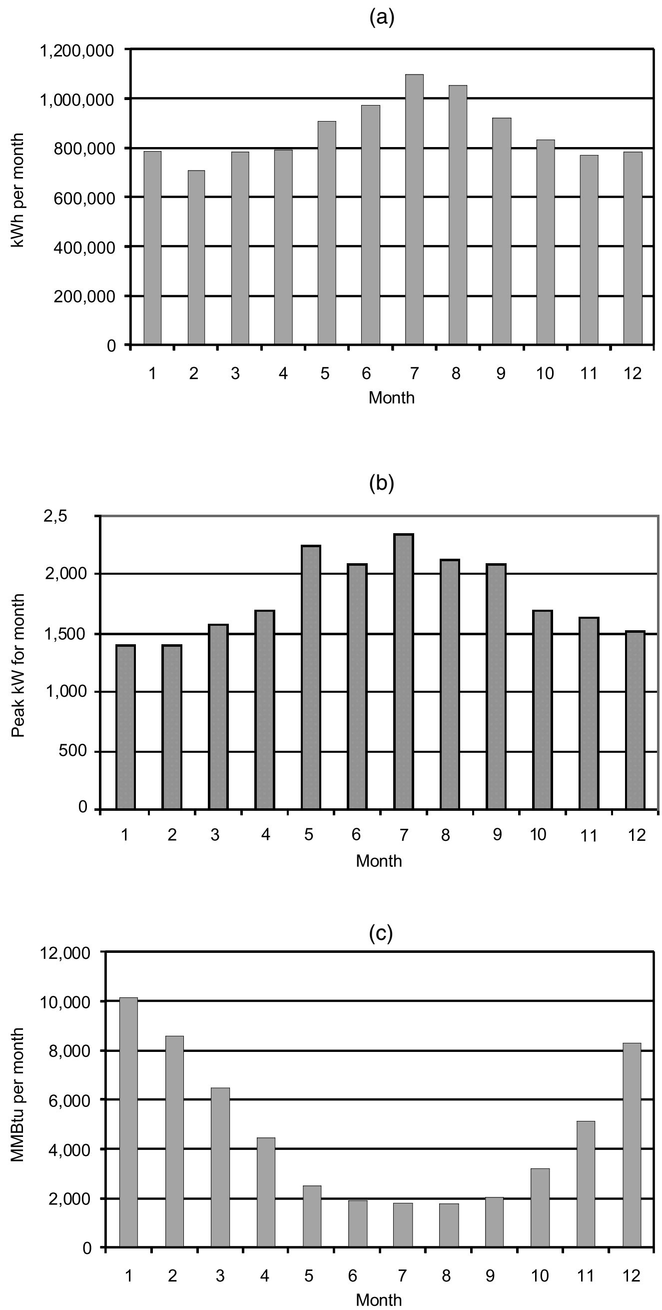


FIGURE 3.1.18 Monthly energy values used in example. (a) Building electrical load in kWh, (b) building demand in kW, and (c) thermal load in MMBtu.

for each study. It is not possible to generalize DR feasibility results for one building in a given location to another building in another location.

The first control mode was a peak-shaving technique where the turbines were operated only when the building electrical load was greater than 1000 kW. At this point, the turbines would come on one by one as the load increased above 1000 kW until all ten were operating. The second control method assumed that the turbines would run whenever possible in an attempt to maximize the annual run time. Both of these techniques were analyzed using two different rates. The rates were based on actual commercial rates from a major metropolitan utility; one rate is a general service rate with no demand component, the other is a time-of-use rate with time-of-use periods for both consumption and demand. The natural gas rate was not changed throughout these studies.

1. Results using general service (GS) rate

The monthly electricity costs for each of the control methods using the general service rate are shown in Figure 3.1.19. No ancillary credits or environmental costs are included in these results; the values shown are based strictly on the utility rate. The spread between the effective electrical and natural gas costs is such that the use of DR is advantageous in this building. It is cheaper to use natural gas to generate electricity on site than it is to purchase the electricity directly from the utility.

2. Results for time-of-use (TOU) rate

A similar analysis was performed using the time-of-use rate for the same building in the same location as above. The monthly electricity cost components are shown in Figure 3.1.20 and are directly comparable to the previous figure.

TABLE 3.1.3 Cost Comparisons

(a) Summary of microturbine performance using general service rate

	Annual Energy Costs ($1000) Elec.	Gas	Change in Annual Cost Elec.	Gas	Total	Int. rate of return
a. Without DG	$1283	$237	—	—	—	—
b. Peak limiting	$1071	$328	–17%	+39%	–8%	12%
c. DG always on	$805	$451	–37%	+91%	–17%	45%

(b) Summary of microturbine performance using time-of-use rate

	Annual Energy Costs ($1000) Elec.	Gas	Change in Annual Cost Elec.	Gas	Total	Int. rate of return
a. Without DG	$951	$237	—	—	—	—
b. Peak limiting	$773	$328	–19%	+39%	–7%	2%
c. DG always on	$638	$451	–33%	+91%	–8%	4%

The summary of the annual costs for the TOU rate is given in Table 3.1.3. These results for the same building, equipment, and control methods do not look promising at all for the GS rate results as shown in part (a) of Table 3.1.3. This is because the effective, aggregated cost of electricity using the time-of-use rate is not as great as with the general service rate. This example serves to illustrate the importance of knowing both detailed load shape and rate schedule information. *Rules of thumb or using results from one DR study for a different situation will result in incorrect economic assessments.* This analysis involved the same building, location, DR equipment, and control methods, yet the economic advantage of the installation of the microturbines depends solely on the utility rates that apply. Finally, we observe that the rate of return is very strongly affected by the control methodology.

Conclusions

This overview of DR in the U.S. has illustrated several key points:

1. Several viable DR technologies now exist.
2. A uniform assessment approach is needed to select the appropriate DR option(s) for a given application; the method must be able to include nonenergy aspects of DR such as ancillary services and emergency power benefits. A separate assessment is needed for each project; rules of thumb do not suffice.
3. New approaches are needed for control and financial dispatch of DR-produced power.

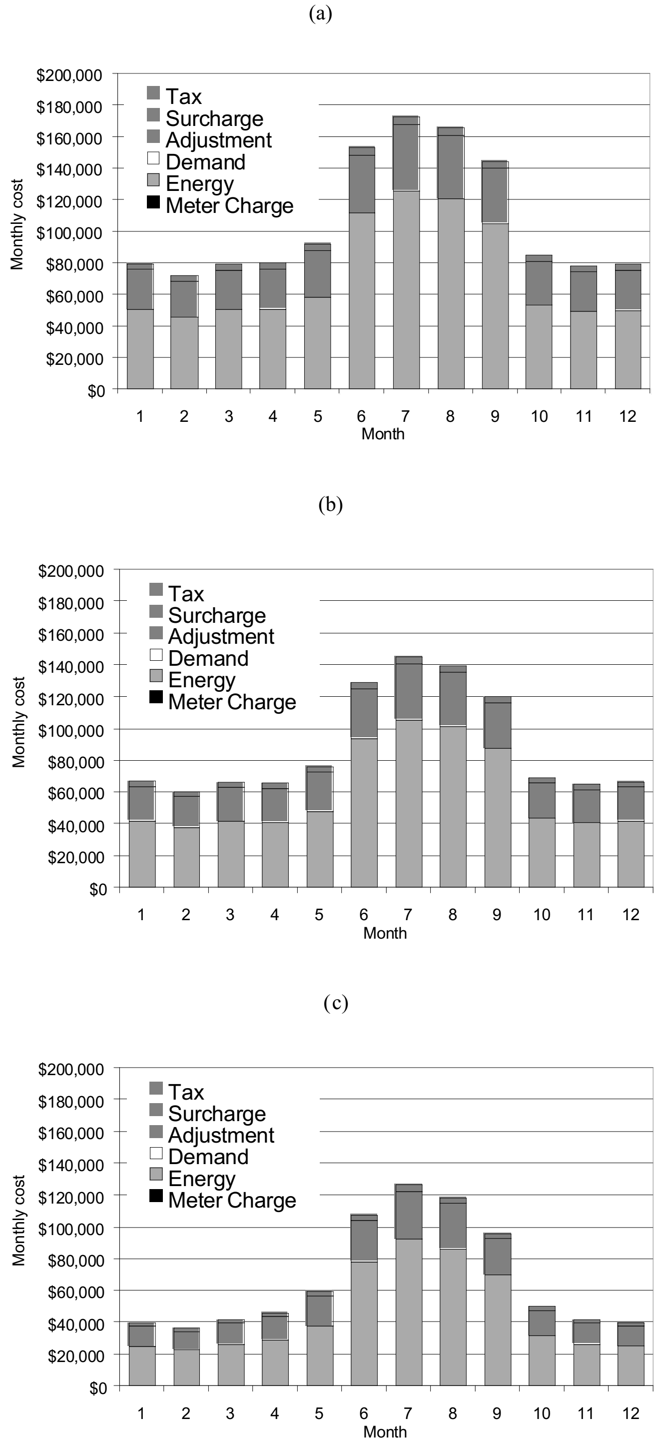
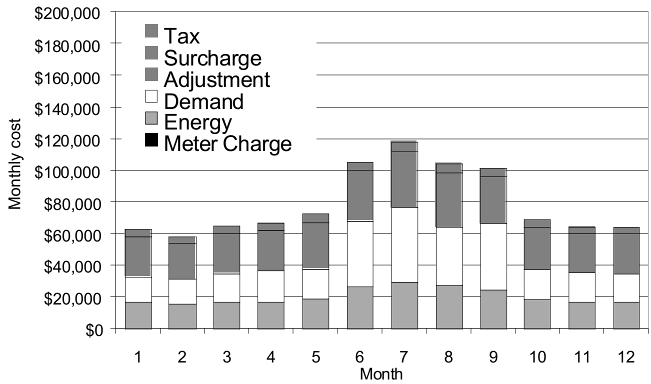
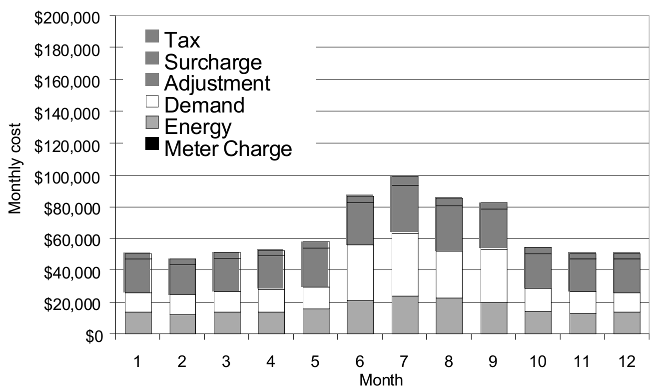


FIGURE 3.1.19 Monthly electricity cost for general service rate. (a) Without microturbines. (b) Turbines run when building load is > 1000 kW. (c) Turbines run at all times.

(a)



(b)



(c)

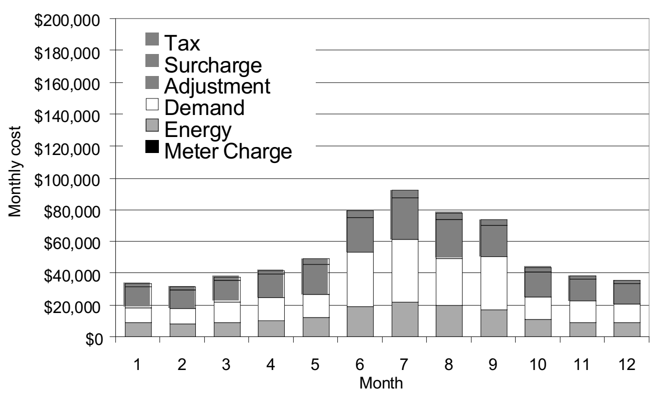


FIGURE 3.1.20 Monthly electricity costs for time-of-use rate. (a) without turbines. (b) turbines run when building load is > 1000 kW. (c) turbines run at all times.

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3.2 Economics and Costing of HVAC Systems

Ari Rabl

3.2.1 Economic Analysis and Optimization

We do not live in paradise and our resources are limited. Therefore it behooves us to try to reduce the cost of heating and cooling to a minimum, subject, of course, to the constraint of providing the desired indoor environment and services. But while capital costs and a operating costs are readily stated in financial terms, other factors such as comfort, convenience, and aesthetics may be difficult or impossible to quantify. Furthermore, there is uncertainty: future energy prices, future rental values, future equipment performance, and future uses of a building are uncertain.

As a way around the difficulties, it is best to approach the design optimization in the following manner. First, one evaluates the total cost for each proposed design or design variation by properly combining all capital and operating costs. Then, knowing the cost of each design, one can select the "best," much like selecting the best product in a store where each product carries a price tag. Proceeding in this way, one separates the factors that can be quantified unambiguously (i.e., cost, according to the price tag), from those that are less tangible (e.g., aesthetics). The calculation of the price is the essence of engineering economics and forms the main part of this section. Optimization and some effects of uncertainty are addressed at the end.

3.2.2 Comparing Present and Future Costs

The Effect of Time on the Value of Money

Before one can compare first costs (i.e., capital costs) and operating costs, one must apply a correction because a dollar (or any other currency unit) to be paid in the future does not have the same value as a dollar available today. This time dependence of money is due to two, quite different, causes. The first is inflation, the well known and ever present erosion of the value of our currency. The second reflects the fact that a dollar today can buy goods to be enjoyed immediately or it can be invested to increase its value by profit or interest. Thus a dollar that becomes available in the future is less desirable than a dollar today; its value must be discounted. This is true even if there is no inflation. Both inflation and discounting are characterized in terms of annual rates.

Let us begin with inflation. To avoid confusion, subscripts are added to the currency signs, indicating the year in which the currency is specified. For example, during the middle of the 1980s the inflation rate r_{inf} in western industrial countries was around $r_{inf} = 4\%$. Thus, a dollar in 1986 is worth only 1/(1+0.04) as much as the same dollar one year before:

$$1.00\ \$_{1986} = \frac{1}{1 + r_{inf}}\ \$_{1985} = \frac{1}{1 + 0.04} = 0.96\ \$_{1985}\,.$$

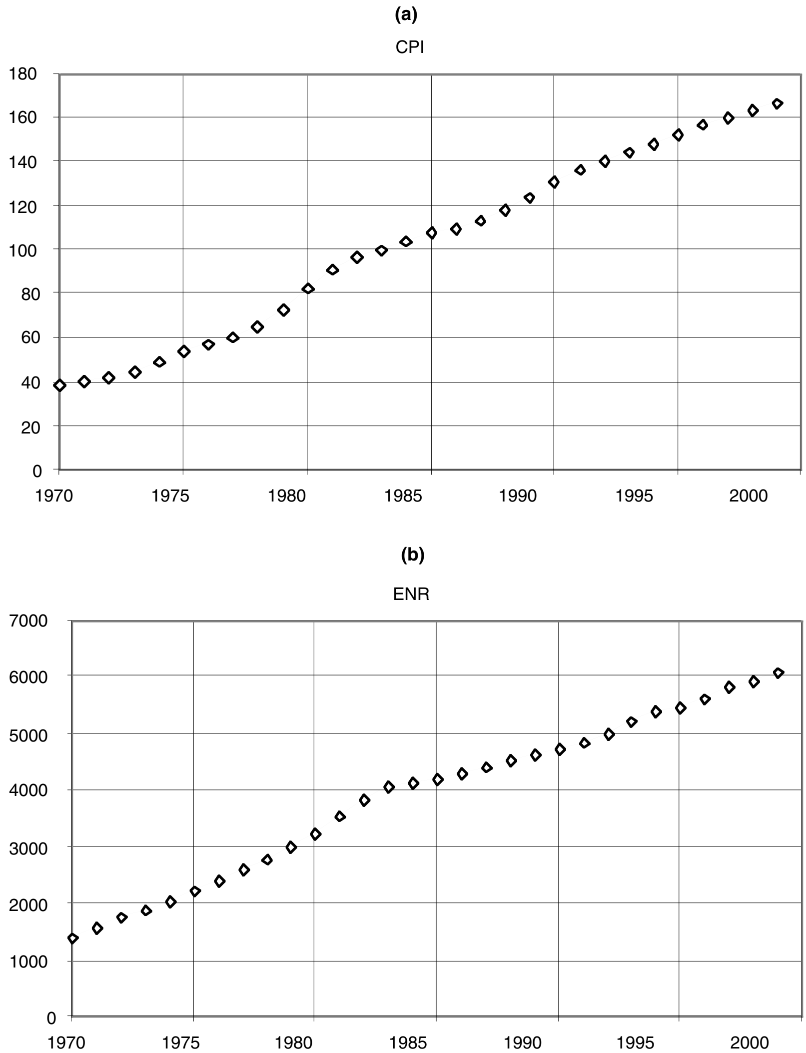

FIGURE 3.2.1 History of various cost indices. (a) CPI = consumer price index (from ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt), (b) ENR = *Engineering News Record* construction cost index.

The definition and measure of the inflation rate are actually not without ambiguities since different prices escalate at different rates and the inflation rate depends on the mix of goods assumed. The most common measure is probably the consumer price index (CPI), an index that was arbitrarily set at 100 in 1983. Its evolution is shown in Figure 3.2.1, along with another index of interest to the HVAC designer — the *Engineering News Record* construction cost index. In terms of the CPI, the average inflation rate from year ref to year ref+n is given by*

$$(1 + r_{inf})^n = \frac{CPI_{ref+n}}{CPI_{ref}}. \tag{3.2.1}$$

*For simplicity, we write the equations as if all growth rates were constant. Otherwise the factor $(1 + r)^n$ would have to be replaced by the product of factors for each year $(1 + r_1)(1 + r_2) \dots (1 + r_n)$. Such a generalization is straightforward, but tedious and of dubious value in practice as it is already risky to predict averages trends without trying to guess a detailed scenario.

Suppose $\$_{1985}$ 1.00 was invested at an interest rate r_{int} = 10%, the *nominal* or *market* rate, as usually quoted by financial institutions. Then, after one year this dollar had grown to $\$_{1986}$ 1.10, but it is worth only $\$_{1985}$ 1.10/1.04 = $\$_{1985}$ 1.06. To show the increase in the real value, it is convenient to define the real interest rate r_{int0} by the relation

$$1 + r_{int0} = \frac{1 + r_{int}}{1 + r_{int}} \tag{3.2.2}$$

or

$$r_{int0} = \frac{r_{int} - r_{inf}}{1 + r_{inf}}.$$

The simplest way of dealing with inflation is to eliminate it from the analysis right at the start by using *constant currency* and expressing all growth rates (interest, energy price escalation, etc.) as real rates, relative to constant currency. After all, one is concerned about the real value of cash flows, not about their nominal values in a currency eroded by inflation. Constant currency is obtained by expressing the *current* or *inflating* currency of each year (i.e., the nominal value of the currency) in terms of equivalent currency of an arbitrarily chosen reference year *ref*. Thus, the current dollar of year *ref+n* has a constant dollar value of

$$\$_{ref} = \frac{\$_{ref+n}}{(1 + r_{inf})^n} \tag{3.2.3}$$

A *real growth rate* r_0 is related to the *nominal growth rate* r analogous to Equation 3.2.2:

$$r_0 = \frac{r - r_{inf}}{1 + r_{inf}}. \tag{3.2.4}$$

For low inflation rates one can use the approximation

$$r_0 \approx r - r_{inf} \quad \text{if} \quad r_{inf} \quad \text{is small.} \tag{3.2.5}$$

Later, as proved in the section entitled "Constant Currency Versus Inflating Currency", an analysis in terms of constant currency and real rates is exactly equivalent to one with inflating currency and nominal rates, if the investment is paid out of equity (i.e., without a loan) and without a tax deduction for depreciation or interest. Slight real differences between the two approaches can arise from the formulas for depreciation and for loan payments (in the U.S., loan payments are usually arranged to have fixed amounts in current currency, and the real value of annual loan payments differs between the two approaches). Therefore, the inflating dollar approach is commonly chosen in the U.S. business world.

However, when the constant dollar approach is correct, it offers several advantages. Having one variable less, it is simpler and clearer. What is more important, the long term trends of real growth rates are fairly well known, even if the inflation rate turns out to be erratic. For example, from 1955 to 1980, the real interest rate on high quality corporate bonds consistently hovered around 2.2% despite large fluctuations of inflation (Jones, 1982), while the high real interest rates of the 1980s were probably a short term anomaly. Riskier investments, such as the stock market, might promise higher returns, but they, too, tend to be more constant in constant currency.

Likewise, prices tend to be more constant when stated in terms of real currency. This is illustrated in Figure 3.2.2 by comparing some energy prices in real and in inflating dollars. For example, the market price (price in inflating currency) of crude oil reached a peak of $36 in 1981, ten times higher than the market price during the 1960s, while in terms of constant currency the price increase over the same period was only a factor of four. Crude oil during oil crises is, of course, an example of extreme price fluctuations. For other goods, the price in constant currency is far more stable (it would be exactly constant in the absence of relative price shifts among different goods). Therefore, it is instructive to think in terms of real rates and real currency.

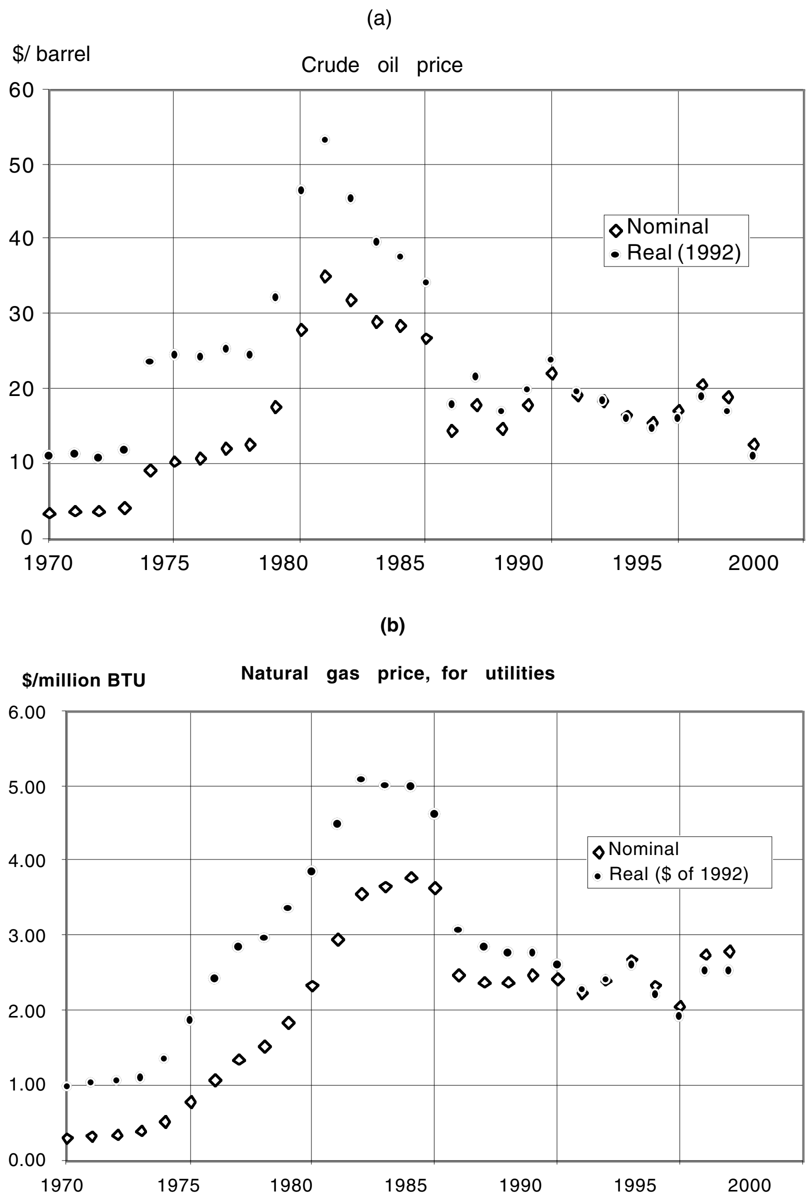

FIGURE 3.2.2 Energy/prices, in constant dollars (solid symbols) and in inflating dollars (hollow symbols). (a) crude oil; (b) natural gas (for utility companies); (c) electricity (average retail price). (From http://www.eia.doe.gov.)

Example 1

Find the nominal and real escalation rates for residential electricity prices between 1970 and 1995.

Given: data in Figure 3.2.2(c); real prices are in $\$_{1992}$.

Find: real growth rate r_0 and nominal growth rate r.

Solution

In 1970 the price was $p_{1970} = 1.7¢_{1970}/kWh = 5.6¢_{1992}/kWh$.

In 1995 the price was $p_{1995} = 6.9¢_{1995}/kWh = 6.4¢_{1992}/kWh$.

The number of years is n = 1995 – 1970 = 25.

Hence, the real growth rate is given by

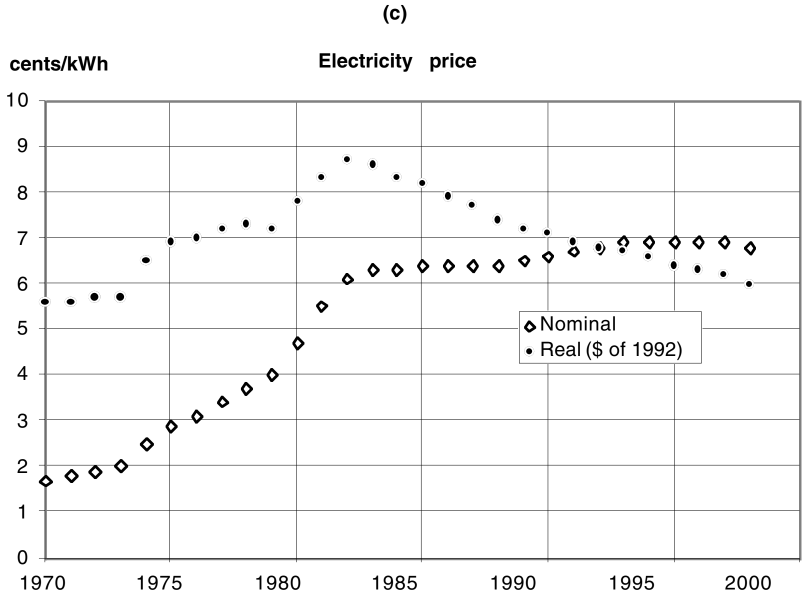

FIGURE 3.2.2 (*continued*)

$$r_0 = -1 + \sqrt[n]{\frac{p_{1995}}{p_{1970}}}$$

$$= -1 + \sqrt[25]{\frac{6.4}{5.6}} = -1 + 1.005 = 0.005 .$$

The nominal growth rate is

$$r = -1 + \sqrt[25]{\frac{6.9}{1.7}} = -1 + 1.058 = 0.058 .$$

Comments: This example highlights the importance of distinguishing between real and nominal growth rates. While the apparent price has grown by almost 6% per year, the real price increased by only 0.5% per year; the inflation rate averaged about 5.3% during this period.

Discounting of Future Cash Flows

As mentioned above, even if there were no inflation, a future cash amount F is not equal to its *present value* P; it must be discounted. The relation between P and its future value F_n n years from now is given by the *discount rate* r_d, defined such that

$$P = \frac{F_n}{(1 + r_d)^n}. \tag{3.2.6}$$

The higher the discount rate, the lower the present value of future transactions.

To determine the appropriate value of the discount rate one has to ask at what value of r_d one is indifferent between an amount P today and an amount $F_n = P/(1 + r_d)^n$ n years from now. That indifference depends on circumstances and individual preferences. Consider a consumer who would put his money in a savings account with 5% interest. His discount rate is 5% because by putting the $1000 into this account he in fact accepts the alternative of (1 + 5%) × $1000 a year from now. If instead he would use it to pay off a car loan at 10%, then his discount rate would be 10%; paying off the loan is like putting the money into a savings account which pays at the loan interest rate. If the money would allow him to avoid an emergency loan at 20%, then his discount rate would be 20%. At the other extreme, if he would hide the money in his mattress, his discount rate would be zero.

The situation becomes more complex when there are several different investment possibilities offering different returns at different risks, such as savings accounts, stocks, real estate, or a business venture. By and large, if one wants the prospect of a higher rate of return one has to accept a higher risk. Thus, as a more general rule, we can say that the appropriate discount rate for the analysis of an investment is the rate of return on alternative investments of comparable risk. In practice that is sometimes quite difficult to determine, and it may be desirable to have an evaluation criterion that bypasses the need to choose a discount rate. Such a criterion is obtained by calculating the profitability of an investment in terms of an unspecified discount rate and then solving for the value of the rate at which the profitability goes to zero. That method, called *internal rate of return*, is explained later in the section entitled "Internal Rate of Return".

As with other growth rates, one can specify the discount rate with or without inflation. If F_n is given in terms of constant currency, designated as F_{n0}, then it must be discounted with the real discount rate r_{d0}. The latter is, of course, related to the market discount rate r_d by

$$r_{d0} = \frac{r_d - r_{inf}}{1 + r_{inf}}. \tag{3.2.7}$$

According to Equation 3.2.4. Present values can be calculated with real rates and real currency or with market rates and inflating currency; the result is readily seen to be the same because multiplying the numerator and denominator of Equation 3.2.6 by $(1 + r_{inf})^n$ one obtains

$$P = \frac{F_n}{(1 + r_d)^n} = \frac{F_n(1 + r_{inf})^n}{(1 + r_{inf})^n(1 + r_d)^n}$$

which is equal to

$$P = \frac{F_{n0}}{(1 + r_{d0})^n}$$

since

$$F_{n0} = \frac{F_n}{(1 + r_{inf})^n} \tag{3.2.8}$$

by Equation 3.2.3.

The ratio P/F_n of present and future value is called *present worth factor*. We designate it with the mnemonic notation

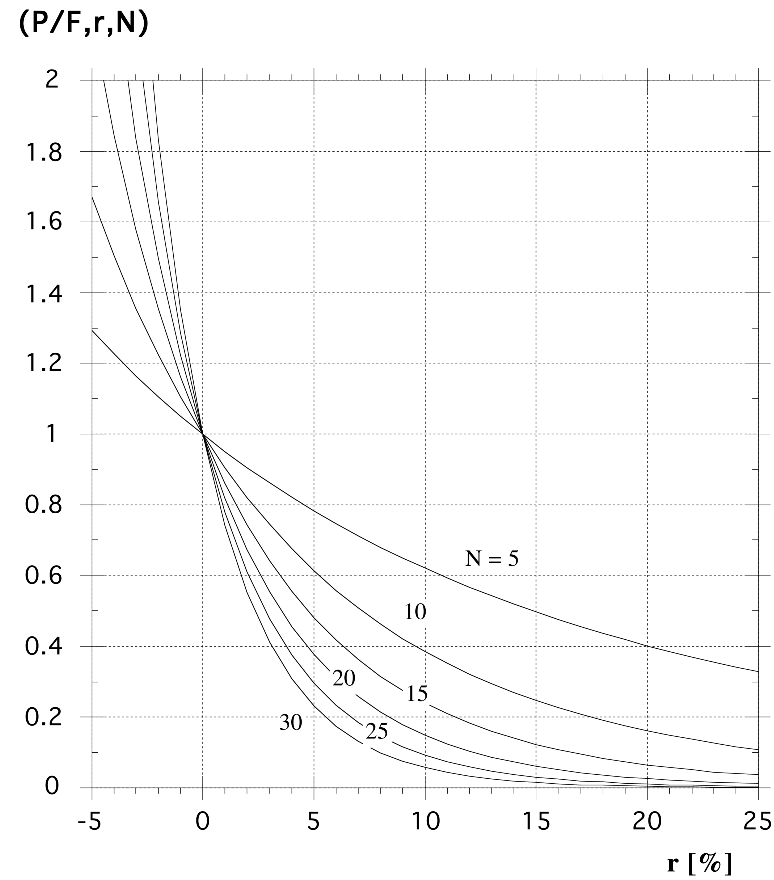

FIGURE 3.2.3 The present worth factor (P/F,r,N) as function of rate r and number of years N.

$$(P/F,r,n) = P/F_n = (1 + r)^{-n} \tag{3.2.9}$$

It is plotted in Figure 3.2.3. Its inverse

$$(F/P,r,n) = \frac{1}{(P/F,r,n)} \tag{3.2.10}$$

is called *compound amount factor*. These factors are the basic tool for comparing cash flows at different times. Note that we have chosen the end-of-year convention by designating F_n as the value at the end of the nth year. Also, we have assumed annual intervals, which is generally an adequate time step for engineering economic analysis; accountants, by contrast, tend to work with monthly intervals, corresponding to the way most regular bills are paid. The basic formulas are the same, but the numerical results differ because of differences in the compounding of interest; this point is explained more fully later in the section called “Discrete and Continuous Cash Flows” in which we pass to the continuous limit by letting the time step approach zero.

Example 2

What might be an appropriate discount rate for analyzing the energy savings from a proposed new cogeneration plant for a university campus? Consider the fact that from 1970 to 1988, the endowment of the university grew by a factor of 8 (current dollars) due to profits from investments.

Given:

growth factor in current dollars = 8.0,

increase in CPI = 118.3/38.9 = 3.04, from Figure 3.2.1a,

over N = 18 years.

Find: real discount rate r_{d0}

Solution

There are two equivalent ways of solving for r_{d0}.

First method: take the real growth factor, 8.0/3.04, and set it equal to

$(1 + r_{d0})^N$.

The result is r_{d0} = 5.52%.

Second method: calculate market rate r_d by setting the market growth in current dollars equal to $(1 + r_d)^N$ and calculate inflation by setting the CPI increase equal to $(1 + r_{inf})^N$.

We find r_d = 12.246% and r_{inf} = 6.371%. Then solve Equation 3.2.7 for r_{d0}, with the result $r_{d0} = \dfrac{0.12246 - 0.06371}{1 + 0.06371}$ = 5.52%, the same as with the first method.

Comments: Choosing a discount rate is not without pitfalls. For the present example, the comparison with the real growth of other long-term investments seems appropriate; of course, there is no guarantee that the endowment will continue growing at the same real rate in the future.

Equivalent Cash Flows and Levelizing

It is convenient to express irregular or variable payments as equivalent uniform payments in regular intervals; in other words, one replaces a nonuniform series by an equivalent uniform series. We refer to this technique as *levelizing*. It is useful because regularity facilitates understanding and planning. To develop the formulas, calculate the present value P of a series of N equal annual payments A. If the first payment occurs at the end of the first year, its present value is $A/(1 + r_d)$. For the second year it is $A/(1 + r_d)^2$, etc. Adding all the present values from year 1 to N, we find the total present value

$$P = \frac{A}{1 + r_d} + \frac{A}{(1 + r_d)^2} + \ldots + \frac{A}{(1 + r_n)^N} \tag{3.2.11}$$

This is a simple geometric series, and the result is readily summed to

$$P = A\frac{1 - (1 + r_d)^{-N}}{r_d} \quad \text{for} \quad r_d \neq 0 \tag{3.2.12}$$

For zero discount rate, this equation is indeterminate, but its limit $r_d \to 0$ is A N, reflecting the fact that the N present values all become equal to A in that case. Analogous to the notation for the present worth factor, we designate the ratio of A and P by

$$(A/P,r_d,N) = \begin{cases} \dfrac{r_d}{1 - (1 + r_d)^N} & \text{for} \quad r_d \quad 0 \\ \dfrac{1}{N} & \text{for} \quad r_d = 0 \end{cases} \tag{3.2.13}$$

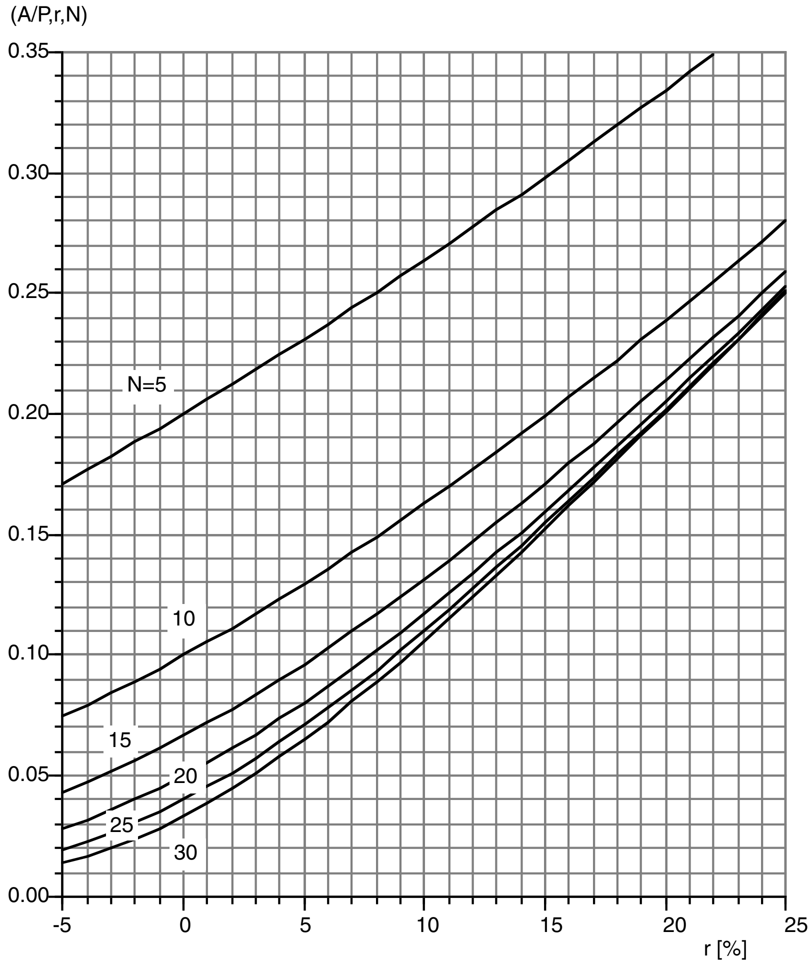

FIGURE 3.2.4 The capital recovery factor (A/P,r,N) as function of rate r and number of years N.

It is called *capital recovery factor* and is plotted in Figure 3.2.4. For the limit of long life, N →, it is worth noting that $(A/P,r_d,N) \rightarrow r_d$ if $r_d > 0$. The inverse is known as *series present worth factor* since P is the present value of a series of equal payments A.

With the help of present worth factor and capital recovery factor, any single expense C_n that occurs in year n, for instance a major repair, can be expressed as an equivalent annual expense A that is constant during each of the N years of the life of the system. The present value of C_n is $P = (P/F,r_d,n)\ C_n$ and the corresponding annual cost is

$$A = (A/P,r_d,N)(P/F,r_d,N)C_n \tag{3.2.14}$$

$$= \frac{r_d}{1-(1+r_d)^{-N}}(1+r_d)^{-n}C_n\,.$$

Example 3

A system has a salvage value of $1000 at the end of its useful life of N = 20 years. What is the equivalent levelized annual value if the discount rate is 8%?

Given: C_{20} = \$1000, N = n = 20 and $r_d = 0.08$.

Find: A.

Lookup values:

$(A/P,r_d,N) = 0.1019$ for Figure 3.2.4 or Equation 3.2.13,

and $(P/F,r_d,n) = 0.2145$ from Figure 3.2.3 or Equation 3.2.9.

Solution

Insert into Equation 3.2.14

$A = (A/P,r_d,N)\ (P/F,r_d,n)\ C_{20} = 0.1019 \times 0.2145 \times 1000$ \$/yr = 21.86 \$/yr.

A very important application of the capital recovery factor is the calculation of loan payments. In principle, a loan could be repaid according to any arbitrary schedule, but, in practice, the most common arrangement is based on constant payments in regular intervals. The portion of A due to interest varies, in a way calculated later in the section on "Principal and Interest," but to find the relation between A and the loan amount L we need not worry about that. Let us first consider a loan of amount L_n that is to be repaid with a single payment F_n at the end of n years. With n years of interest, at loan interest rate r_l, the payment must be

$$F_n = L_n(1 + r_l)^n.$$

Comparison with the present worth factor shows that the loan amount is the present value of the future payment F_n, discounted at the loan interest rate.

A loan that is to be repaid in N equal installments can be considered as the sum of N loans, the nth loan to be repaid in a single installment A at the end of the nth year. Discounting each of these payments at the loan interest rate and adding them we find the total present value; it is equal to the total loan amount

$$L = P = \frac{A}{1 + r_l} + \frac{A}{(1 + r_l)^2} + \ldots + \frac{A}{(1 + r_l)^N} \qquad (3.2.15)$$

This is just the series of the capital recovery factor. Hence, the relation between annual loan payment A and loan amount L is

$$A = (A/P,r_l,N)\ L. \qquad (3.2.16)$$

Now the reason for the name *capital recovery factor* becomes clear; it is the rate at which a bank recovers its investment in a loan.

Example 4

A home buyer obtains a mortgage of \$100,000 at interest rate 8% over 20 years. What are the annual payments?

Given: L = \$100,000, r_l = 8%, N = 20 yr.

Find: A.

Solution

From Figure 3.2.4 the capital recovery factor is 0.1019, and the annual payments are \$10,190, approximately one tenth of the loan amount.

Some payments increase or decrease at a constant annual rate. It is convenient to replace a growing or diminishing cost by an equivalent constant or *levelized* cost. Suppose the price of energy is p_e at the start of the first year, escalating at an annual rate r_e while the discount rate is r_d. If the annual energy consumption Q is constant, then the present value of all the energy bills during the N years of system life is

$$P_e = Qp_e\left\{\left(\frac{1+r_e}{1+r_d}\right)^1 + \left(\frac{1+r_e}{1+r_d}\right)^2 + \ldots + \left(\frac{1+r_e}{1+r_d}\right)^N\right\} \tag{3.2.17}$$

assuming the end-of-year convention described above. As in Equation 3.2.3 we introduce a new variable $r_{d,e}$ defined by

$$1 + r_{d,e} = \frac{1+r_d}{1+r_e} \tag{3.2.18}$$

or

$$r_{d,e} = \frac{r_d - r_e}{1+r_e}(\approx r_d - r_e \quad \text{if} \quad r_e \ll 1), \tag{3.2.19}$$

which allows us to write P_e as

$$P_e = (P/A,r_{d,e},N)\ Q\ p_e. \tag{3.2.20}$$

Since $(A/P,r_d,N)$ is the inverse of $(A/P,r_d,N)$, we can write this as

$$P_e = (P/A,r_d,N)\ Q\left[\frac{(A/P,r_d,N)}{(A/P,r_{d,e},N)}p_e\right]$$

If the quantity in brackets were the price, this would only be the formula without escalation. Let us call this quantity the *levelized* energy price $\bar{p}_e$

$$\bar{p}_e = \left[\frac{(A/P,r_d,N)}{(A/P,r_{d,e},N)}p_e\right] \tag{3.2.21}$$

It allows us to calculate the costs as if there were no escalation. Levelized quantities can fill a gap in our intuition which is ill prepared to gauge the effects of exponential growth over an extended period. The levelizing factor

$$\text{levelizing factor} = \frac{(A/P,r_d,N)}{(A/P,r_{d,e},N)} \tag{3.2.22}$$

tells us, in effect, the average of a quantity that changes exponentially at a rate r_e while being discounted at a rate r_d over a lifetime of N years. It is plotted in Figure 3.2.5 for a wide range of the parameters.

Example 5

The price of fuel is p_e = 5 \$/GJ at the start of the first year, growing at a rate r_e = 4% while the discount rate is r_d = 6%. What is the equivalent levelized price over N = 20 years?

Given: p_e = 5 \$/GJ, r_e = 4%, r_d = 6%, N = 20 yr.

Find: $\bar{p}_e$

Solution

From Figure 3.2.5 the levelizing factor is 1.44. Hence the levelized fuel price is $\bar{p}_e = 1.44 \times 5$ \$/GJ = 7.20 \$/GJ.

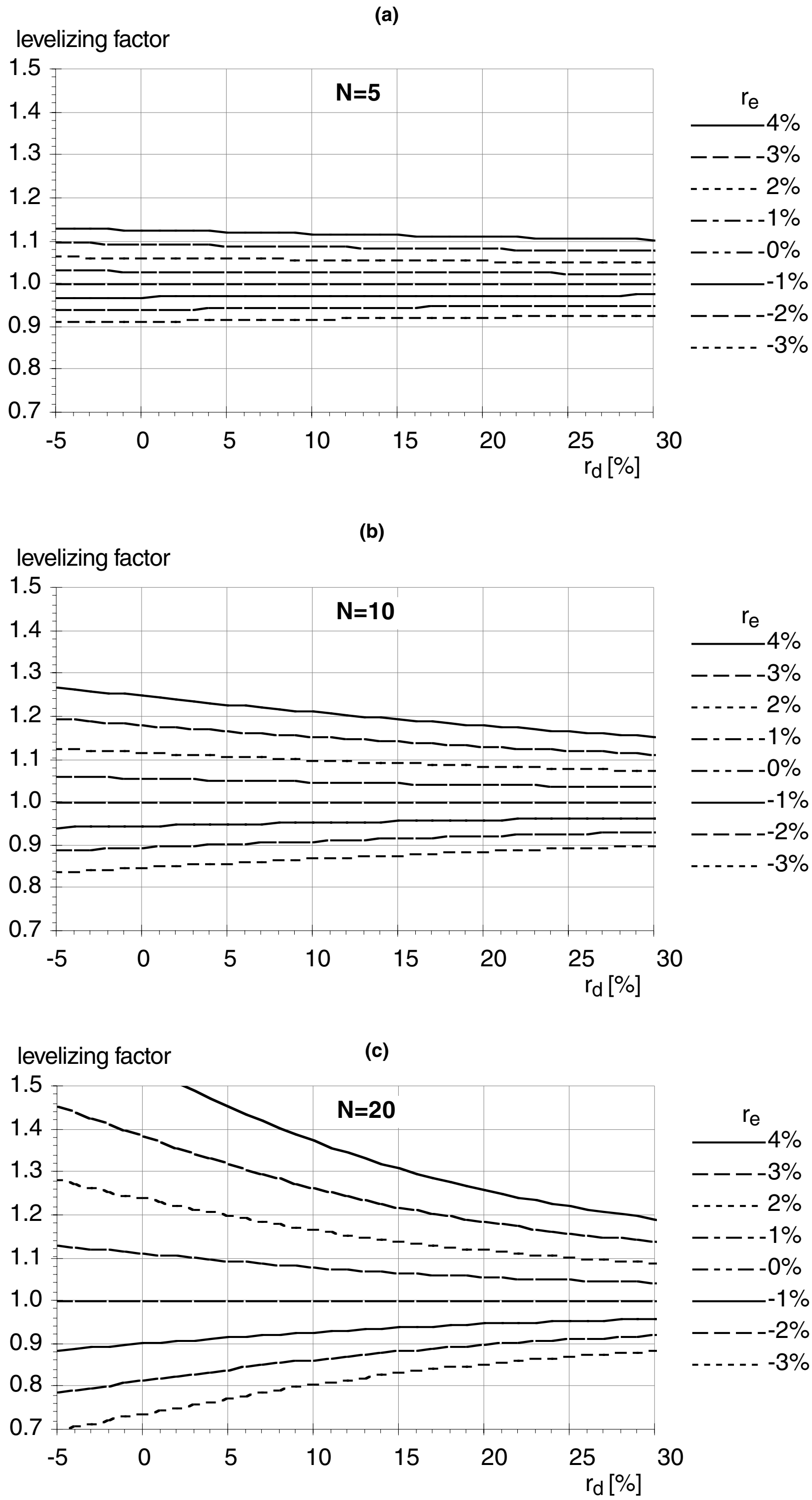

FIGURE 3.2.5 Levelizing factor $(A/P,r_d,N)/(A/P,r_{d,e},N)$ as a function of r_d and $r_{d,e}$. (a) N = 5 yr; (b) N = 10 yr; (c) N = 20 yr.

Several features may be noted in Figure 3.2.5. First, the levelizing factor increases with cost escalation r_e, being unity if $r_e = 0$. Second, for a given escalation rate, the levelizing factor decreases as the discount rate increases, reflecting the fact that a high discount rate de-emphasizes the influence of high costs in the future.

Discrete and Continuous Cash Flows

The above formulas suppose that all costs and revenues occur in discrete intervals. That is common engineering practice, in accord with the fact that bills are paid in discrete installments. Thus, growth rates are quoted as annual changes even if growth is continuous. It is instructive, however, to consider the continuous case.

TABLE 3.2.1 Discrete and Continuous Formulas for Economic Analysis, with Growth Rate r and Time Horizon N

Quantity known	Quantity to be found	Factor	Expression for discrete analysis	Expression for continuous analysis
P	F	(F/P,r,N)	$(1 + r)^N$	$\exp(rN)$
F	P	(P/F,r,N)	$(1 + r)^{-N}$	$\exp(-rN)$
P	A	(A/P,r,N)	$\dfrac{r}{1-(1+r)^{-N}}$	$\dfrac{\exp(r)-1}{1-\exp(-rN)}$
A	P	(P/A,r,N)	$\dfrac{1-(1+r)^{-N}}{r}$	$\dfrac{1-\exp(-rN)}{\exp(r)-1}$

Note: The rates for the discrete and continuous formulas are related by Equation 3.2.24.

Let us establish the connection between continuous and discrete growth by way of an apocryphal story about the discovery of *e*, the basis of natural logarithms. Before the days of compound interest, a mathematician who was an inveterate penny pincher thought about possibilities of increasing the interest he earned on his money. He realized that if the bank gives interest at a rate of r per year, he could get even more by taking the money out after half a year and reinvesting it to earn interest on the interest as well. With *m* compounding intervals per year the money would grow by a factor

$$(1 + r/m)^m$$

and the larger m, the larger this factor. Of course, he looked at the limit m → and found the result

$$\lim_{m\varnothing}(1+r/m)^m = e^r \quad \text{with} \quad e = 2.71828\ldots \tag{3.2.23}$$

At the end of one year the growth factor is $(1 + r_{ann})$ with annual compounding at a rate r_{ann}, while with continuous compounding at a rate r_{cont} the growth factor is $\exp(r_{cont})$. If the two growth factors are to be the same, the growth rates must be related by

$$1 + r_{ann} = \exp(r_{cont}). \tag{3.2.24}$$

With this replacement of rates, the continuous formulas in Table 3.2.1 yield the same results as the discrete ones. Similarly, with m compounding intervals at rate r_m is equivalent to annual compounding if one takes

$$1 + r_{ann} = (1 + r_m/m)^m. \tag{3.2.25}$$

Example 6

A bank quotes a nominal interest rate of 10% (i.e., annual growth without compounding). What is the equivalent annual growth rate with monthly, daily, and continuous compounding?

Solution

For monthly compounding take m = 12 in Equation 3.2.25, with the result

$r_{12} = (1 + 0.1/12)^{12} - 1 = 0.104713$

With daily compounding we have

$r_{365} = (1 + 0.1/365)^{365} - 1 = 0.105155$

and with continuous compounding

$r_{cont} = \exp(0.1) - 1 = 0.105171.$

Comment: Beyond monthly compounding the differences are very small.

For small rates the first three terms in the series expansion of the exponential give an approximation

$$r_{ann} \approx r_{cont}\,(1 + r_{cont}/2)$$

which is convenient if one does not have a calculator at hand.

The Rule of Seventy for Doubling Times

Most of us do not have a good intuition for exponential growth. As a helpful tool we present therefore the rule of seventy for doubling times. The doubling time N_2 is related to the continuous growth rate r_{cont} by

$$2 = \exp(N_2 r_{cont}) \tag{3.2.26}$$

Solving the exponential relation for N_2 we obtain

$$N_2 = \frac{\ln(2)}{r_{cont}} = \frac{0.693\ldots}{r_{cont}}.$$

The product of doubling time and growth rate in units of percent is very close to 70 years

$$N_2 r_{cont} \times 100 = 69.3 \ldots \text{ yr} \approx 70 \text{ yr}. \tag{3.2.27}$$

In terms of annual rates, the relation would be

$$N_2 = \frac{\ln(2)}{\ln(1 + r_{ann})},$$

numerically close to Equation 3.2.27 for small rates, but less convenient.

Example 7

Population growth rates average 2% for the world as a whole and reach 4% in certain countries. What are the corresponding doubling times?

Solution

70/2 = 35 yr for the world,

and 70/4 = 17.5 yr for countries with 4% growth.

Example 8

A consultant presents an economic analysis of an energy investment with N = 20 yr, assuming a 10% escalation rate for energy prices without stating the inflation rate. Is that reasonable?

Solution

A growth rate of 10% implies a doubling time of 7 years. There would be almost three doublings in 20 years, with a final energy price almost eight times the original. In constant dollars that would clearly be an absurd hypothesis. A totally different conclusion emerges if the inflation were 6%: then the real growth rate would be only 10 – 6 = 4%, and the doubling time 17.5 years in constant currency; although extreme, that is not inconceivable given our experience since the 1973 oil shock.

Comment: There are two lessons:

1. Never state growth rate or discount rate without indicating the corresponding inflation.
2. Be careful about assuming large growth rates over long time horizons. Use the rule of 70 to check whether the implications for the end of the time horizon make sense.

3.2.3 The Life Cycle Cost

Cost Components

A rational decision is based on the true total cost, which is the sum of the present values of all cost components and is called *life cycle cost.* The cost components relevant for the HVAC engineer are

- Capital cost (total initial investment)
- Energy costs
- Costs for maintenance, including major repairs
- Resale value
- Insurance
- Taxes

There is some arbitrariness in this assignment of categories. One could make a separate category for repairs, or one could include energy among O&M (operation and maintenance) cost, as is done in some industries. There is, however, a good reason for keeping energy apart. In buildings, energy costs dominate the other O&M costs, and they can grow at a different rate. Electric rates usually contain charges for peak demand in addition to charges for energy (see the section on "Demand Charge" discussed later). As a general rule, if an item is important it merits separate treatment.

Rental income needs to be included if one wants to evaluate the profitability of the building, or if one wants to compare design options that would affect the rent. It can be left out of the picture if one is concerned only with comparing design options that do not differ in their effect on rental income. The same is true for cleaning, security, and fire protection. *Usually, when comparing two options, there is no need to include terms that would be the same for each.* For example, when choosing between two chillers, one can restrict one's attention to the costs associated directly with the chillers (capital cost, energy, maintenance), without worrying about the heating system if it is not affected. In some cases it becomes necessary to account for the effects of taxes, because of tax deductions for interest payments and depreciation; these items are discussed below followed by the equation for the complete system cost.

Principal and Interest

In the U.S., interest payments are deductible from the income tax, while payments for the reimbursement of the loan are not. A tax paying investor, therefore, needs to know what fraction of a loan payment is due to interest. As explained earlier in the section on "Equivalent Cash Flows and Levelizing," it is assumed that a loan of duration N_l is repaid in N_l regular and equal payments A. (In this section we take N and N_l in years, but the formulas are valid for any choice of units. For billing purposes, the month is frequently chosen as the payment period. Slight numerical differences in the payments are due to compound interest.) Consider the nth payment, and let I_n = interest and P_n = principal (loan reimbursement); their sum A is constant

$$I_n + P_n = A. \tag{3.2.28}$$

Up to this point, n–1 payments have been made, so the debt remaining (on a loan of amount L) is

$$\text{remaining debt} = L - P_1 - P_2 - \ldots P_{n-1}. \tag{3.2.29}$$

At a loan interest rate r_l the interest for the nth period is

$$I_n = r_l(L - P_1 - P_2 - \ldots - P_{n-1}). \tag{3.2.30}$$

Comparing I_{n+1} with I_n one finds

$$I_{n+1} = I_n - r_l P_n \tag{3.2.31}$$

By means of Equation 3.2.28, one can eliminate P_n with the result

$$I_{n+1} = (1 + r_l)I_n - r_l A. \tag{3.2.32}$$

This recursion relation has the solution

$$I_n = (1 + r_l)^{n-1}\, r_l L + [1 - (1 + r_l)^{n-1}]\, A \tag{3.2.33}$$

as can readily be proved by mathematical induction. Since A and L are related by $A = (A/P,r_l,N_l)\, L$, where N_l is the duration of the loan and $(A/P,r_l,N_l)$ the capital recovery factor of Equation 3.2.13, this can be rewritten in the form

$$I_n/A = 1 - (1 + r_l)^{n-1-N_l}. \tag{3.2.34}$$

It is worth noting the period n enters only in the combination $(n - N_l)$, implying the fractional allocation to principal and interest depends only on the number of periods $(n - N_l)$ left in the loan, not on the original life of the loan. A loan has no memory, so to speak.

In general, the loan interest rate r_l differs from the discount rate r used for the economic analysis, and the loan life N_l may be different from the system life N. Inserting $A = (A/P,r_l,N_l)$ into Equation 3.2.34, we find that the interest payment I is related to loan amount L by

$$I_n = [1 - (1 + r_l)^{n-1-N_l}]\, (A/P,r_l,N_l)\, L. \tag{3.2.35}$$

The present value P_{int} of the total interest payments is found by discounting each I with the discount rate r and summing over n

$$P_{int} = \sum_{n=1}^{N_l} \frac{1 - (1 + r_l)^{n-1-N_l}}{(1 + r_d)^n} (A/P,r_l,N_l)L\,. \tag{3.2.36}$$

Using the formula for geometric series, this can be transformed to

$$P_{int} = \left\{ \frac{(A/P,r_l,N_l)}{(A/P,r_d,N_l)} - \frac{(A/P,r_l,N_l) - r_l}{(1 + r_l)(A/P,r_{d1},N_l)} \right\} L \tag{3.2.37}$$

with

$$r_{dl} = (r_d - r_l)/(1 + r_l).$$

If the incremental tax rate is τ, the total tax payments are reduced by $\tau\ P_{int}$ (assuming a constant tax rate; otherwise, the tax rate would have to be included in the summation).

Example 9

A solar water heating system costing \$2000 is financed with a 5-year loan at $r_l = 8\%$. The tax rate is $\tau = 40\%$. How much is the tax deduction for interest worth if the discount rate is $r_d = 8\%$?

Given:

$L = \$2000,\ r_l = 8\%,\ r_d = 8\%,\ \tau = 40\%.$

Find:

P_{int}

Lookup values:

$(A/P,r_{dl},N_l) = 0.20$ and $(A/P,r_l,N_l) = 0.2505$ from Equation 3.2.13

Solution

We have $r_{dl} = 0$, since $r_l = r_d$.

Also $(A/P,r_{dl},N_l) = 0.20$,

and $(A/P,r_l,N_l) = 0.2505 = (A/P,r_d,N_l)$.

Thus the present value of the interest payments is, from Equation 3.2.37,

$$P_{int} = \left\{1 - \frac{0.2505 - 0.08}{1.08 \times 0.20}\right\} \times \$2000 = \$421.$$

At the stated tax rate that is worth $0.40 \times \$421 = \$168$.

Depreciation and Tax Credit

U.S. tax law allows business property to be depreciated. This means that for tax purposes the value of the property is assumed to decrease by a certain amount each year, and this decrease is treated as a tax deductible loss. For the economic analysis, one needs to express the depreciation as an equivalent present value. The details of the depreciation schedule have been changing with the tax reform of the 1980s. Instead of trying to present the full details, which can be found in Internal Revenue Service publications, we merely note the general features. In any year n, a certain fraction $f_{dep,n}$ of the capital cost (minus salvage value) can be depreciated. For example, in the simple case of straight line depreciation over N_{dep} years

$$f_{dep,n} = 1/N_{dep} \text{ for straight line depreciation.} \tag{3.2.38}$$

To obtain the total present value, one multiplies by the present worth factor and sums over all years from 1 to N

$$f_{dep} = \sum_{n=1}^{N_{dep}} f_{dep,n}(P/F,r_d,n)\,. \tag{3.2.39}$$

For straight line depreciation the sum is

$$f_{dep} = \frac{(P/A,r_d,N_{dep})}{N_{dep}} \text{ for straight line depreciation.} \tag{3.2.40}$$

A further feature of some tax laws is the tax credit. For instance, in the U.S. for several years around 1980, tax credits were granted for certain renewable energy systems. If the tax credit rate is τ_{cred} for an investment C_{cap}, the tax liability is reduced by $\tau_{cred}\ C_{cap}$.

Example 10

A machine costs $10,000 and is depreciated with straight line depreciation over 5 years, and the salvage value after 5 years is $1000. Find the present value of the tax deduction for depreciation if the incremental tax rate is $\tau = 40\%$, and the discount rate $r_d = 15\%$.

Given:

$C_{cap} = 10$ k$,

$C_{salv} = 1$ k$,

$N = 5$ yr,

$\tau = 0.4$,

$r_d = 0.15$.

Find: $\tau \times f_{dep}\ (C_{cap} - C_{salv})$

Lookup values:

$$f_{dep} = \frac{(P/A,0.15,5\ \text{yr})}{5\ \text{yr}} = \frac{(1/0.2983)}{5} = 3.3523/5 = 0.6705, \text{ from Equation 3.2.40.}$$

Solution

For tax purposes, the net amount to be depreciated is the difference

$C_{cap} - C_{salv} = (10 - 1)$ k$ = 9 k$,

and with straight line depreciation $1/N_{dep} = 1/5$ of this can be deducted from the tax each year.

Thus, the annual tax is reduced by $\tau \times (1/5) \times 9$ k$ = 0.40×1.8 k$ = 0.72 k$ for each of the five years.

The present value of this tax reduction is

$\tau \times f_{dep}\ (C_{cap} - C_{salv}) = 0.40 \times 0.6705 \times 9$ k$ = 2.41 k$.

Comment: The present value of the reduction would be equal to 5×0.72 k$ = 3.6 k$ if the r_d were zero. The discount rate of 15% reduces the present value by almost a third to $0.6705 = f_{dep}$.

Demand Charge

The cost of producing electricity has two major components: fuel and capital (for power plant and distribution system). As a consequence, the cost of electricity varies with the total load on the grid. To the extent that it is practical, utility companies try to base the rate schedule on their production cost. Thus, the rates for large customers contain two items: one part of the bill is proportional to the energy, and the other is proportional to the peak demand. (For most individual houses, the bill contains only an energy charge because the cost of separate meters was once considered to be too high.) If the monthly demand charge is $p_{dem} = 10$ $/kW and the energy charge $p_e = 0.07$ $/kWh, a customer with monthly energy consumption Q_m and peak demand P_{max} will receive a total bill of

$$\text{monthly bill} = Q_m p_e + P_{max} p_{dem} \tag{3.2.41}$$

There are many small variations from one utility company to another. In most cases, p_e and p_{dem} depend on time of day and time of year, being higher during the system peak than off peak. In regions with extensive air conditioning, the system peak occurs in the afternoon of the hottest days. In regions with much electric heating, the peak is correlated with outdoor temperature. Some companies use what is called a "ratcheted" demand charge; it has the effect of basing the demand charge on the annual rather than the monthly peak.

Example 11

A 100 ton electric chiller with COP = 3 is used for 8 months of the year (running at 100% capacity at least once per month during 4 months and at 50% capacity at least once per month during 4 months), and the total load is equivalent to 1000 hours at peak capacity (a typical value around the belt from New York to Denver). What is the annual electricity bill, if $p_e = 0.10$ \$/kWh$_e$ and $p_{dem} =$ 10 \$/kW$_e$ per month?

Given:

$P_{max,t} = 100$ ton $\times$ 3.516 kW$_t$/ton, with COP = 3 kW$_t$/kW$_e$,

annual energy = $P_{max} \times$ 1000 h,

demand P_{max} for 4 months and $0.5 \times P_{max}$ for 4 months,

$p_e = 0.10$ \$/kWh$_e$,

$p_{dem} = 10$ \$/kW$_e$ per month.

Find: annual bill.

Solution

Peak demand P_{max} = (100 ton $\times$ 3.516 kW$_t$/ton)/(3 kW$_t$/kW$_e$) = 117.2 kW$_e$.

annual energy Q = $P_{max,e} \times$ 1000 h = 117,200 kWh$_e$.

annual bill = $Q\, p_e + P_{max}\, p_{dem} \times (4 \times 1 + 4 \times 0.5)$

= 117,200 kWh$_e$ $\times$ 0.10 \$/kWh$_e$ + 117.2 kW$_e$ $\times$ 10 \$/kW$_e$ $\times$ 6

= \$11,720 + \$7032

= \$18,752.

Comments: In a real building, the precise value of the peak demand may be difficult to predict because it depends on the coincidence of the demands of individual pieces of equipment.

The total cost per kWh depends on the load profile. The more uneven the profile, the higher the cost. To take an extreme example, suppose the chiller were used only one hour per year, at full capacity. Then, with the rate structure of this example, the demand charge would be \$1172 while the energy charge would be only \$11.72, all that for consuming 1 kWh of energy. The total cost per kWh would be \$1172 + 11.72 = \$1183.72 for 117.2 kWh, an effective electricity price of 10.10 \$/kWh. This illustrates the interest of load leveling devices, such as cool storage for electric chillers.

The Complete Formula

The equations for a business investment can be stated in terms of before-tax cost or after-tax cost. Consider the purchase of fuel, with a market price of 5 \$/GJ, by a business that is subject to an income tax rate $\tau = 40\%$. Fuel, like all business expenditures, is tax deductible. And it is ultimately paid by profits. To purchase 1 GJ, one takes \$5 of profits before taxes; this reduces the tax liability by \$5 $\times$ 40% = \$2, resulting in a net cost of only \$3 after taxes.

We could do the accounting before or after taxes; the former counts the cash payments, the latter the net (after-tax) values. The two modes differ by a factor $(1 - \tau)$ where τ is the income tax rate. For example, if the market price of fuel is 5 \$/GJ and the tax rate $\tau = 40\%$, then the before-tax cost of fuel is 5 \$/GJ and the after-tax cost $(1 - \tau) \times 5$ \$/GJ = 3 \$/GJ. Stated in terms of *after-tax cost*, the complete equation for the life cycle cost of an energy investment can be written in the form

$$
\begin{aligned}
C_{life} &\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad (3.2.42)\\
&= C_{cap}\,\{(1 - f_l) && \text{down payment}\\
&\quad + f_l\,\frac{(A/P,r_1,N_1)}{(A/P,r_d,N_1)} && \text{cost of loan}\\
&\quad - \tau f_l\left[\frac{(A/P,r_1,N_1)}{(A/P,r_d,N_1)} - \frac{(A/P,r_1,N_1) - r_1}{(1 + r_1)(A/P,r_{d,1},N_1)}\right] && \text{tax deduction for interest}\\
&\quad - \tau_{cred} && \text{tax credit}\\
&\quad - \tau f_{dep}\,\} && \text{depreciation}\\
&\quad - C_{salv}\left(\frac{1 + r_{inf}}{1 + r_d}\right)^N (1 - \tau) && \text{salvage}\\
&\quad + Q\,p_e\,\frac{1 - \tau}{(A/P,r_{d,e},N)} && \text{cost of energy}\\
&\quad + P_{max}\,p_{dem}\,\frac{1 - \tau}{(A/P,r_{d,dem},N)} && \text{cost of demand}\\
&\quad + A_m\,\frac{1 - \tau}{(A/P,r_{d,M},N)}\,\} && \text{cost of maintenance}
\end{aligned}
$$

where

A_M	=	annual cost for maintenance [in first year \$]
C_{cap}	=	capital cost [in first year \$]
C_{salv}	=	salvage value [in first year \$]
f_{dep}	=	present value of depreciation, as fraction of C_{cap}
f_l	=	fraction of investment paid by loan
N	=	system life [yr]
N_l	=	loan period [yr]
p_e	=	energy price [in first year \$/GJ]
Q	=	annual energy consumption [GJ]
r_d	=	market discount rate
r_e	=	market energy price escalation rate
$r_{d,e}$	=	$(r_d - r_e)/(1 + r_e)$
r_{dem}	=	market demand charge escalation rate
$r_{d,dem}$	=	$(r_d - r_{dem})/(1 + r_{dem})$
r_{inf}	=	general inflation rate
r_l	=	market loan interest rate
$r_{d,l}$	=	$(r_d - r_l)/(1 + r_l)$
r_M	=	market escalation rate for maintenance costs
$r_{d,M}$	=	$(r_d - r_M)/(1 + r_M)$
τ	=	incremental tax rate
τ_{cred}	=	tax credit

If there are several forms of energy, e.g., gas and electricity, the term $Q\ p_e$ is replaced by a sum over the individual energy terms. Many other variations and complications are possible; for example, the salvage tax rate could be different from τ.

Example 12

Find the life cycle cost of the chiller of Example 11 under the following conditions:

Given:

system life $N = 20$ yr,

loan life $N_l = 10$ yr,

depreciation period $N_{dep} = 10$ yr, straight line depreciation

discount rate $r_d = 0.15$,

loan interest rate $r_l = 0.15$,

energy escalation rate $r_e = 0.01$,

demand charge escalation rate $r_{dem} = 0.01$,

maintenance cost escalation rate $r_M = 0.01$,

inflation $r_{inf} = 0.04$,

loan fraction $f_l = 0.7$,

tax rate $\tau = 0.5$,

tax credit rate $\tau_{cred} = 0$,

capital cost (at 400 \$/ton) $C_{cap} = 40$ k\$,

salvage value $C_{salv} = 0$,

annual cost of maintenance $A_M = 0.8$ k\$/yr (= 2% of C_{cap}),

capacity 100 ton = 351.6 kW_t,

peak electric demand 351.6 kW_t/COP = 117.2 kW_e,

annual energy consumption Q = 100 kton·h = 351.6 MWh_t,

electric energy price p_e = 10 cents/kWh_e = 100 \$/MWh_e,

demand charge p_{dem} = 10 \$/kW_e·month, effective during 6 months of the year.

The rates are market rates.

Find: C_{life}.

Lookup values:

$r_{d,l} = 0.0000$	$(A/P,r_l,N_l) = 0.1993$
$r_{d,e} = 0.1386$	$(A/P,r_d,N_l) = 0.1993$
$r_{d,dem} = 0.1386$	$(A/P,r_{d,l},N_l) = 0.1000$
$r_{d,M} = 0.1386$	$(A/P,r_d,N) = 0.1598$
	$(A/P,r_{d,e},N) = 0.1498$
$(1+r_{inf})/(1+r_d) = 0.9043$	$(A/P,r_{d,dem},N) = 0.1498$

f_{dep} = 0.502 from Equation 3.2.40 $\quad (A/P,r_{d,M},N) = 0.1498$

Solution

Components of C_{life} [all in k$] as per Equation 3.2.42

down payment	12.0
cost of loan	28.0
tax deduction for interest	–8.0
tax credit	0.0
depreciation	–10.0
salvage value	0.0
cost of energy	39.1
cost of demand charge	23.5
cost of maintenance	2.7
Total = C_{life}	87.3

Comments:

a. A spreadsheet is recommended for this kind of calculation. Standard business calculators contain most needed functions.
b. The cost of energy and demand is higher than the capital cost.

Cost per Unit of Delivered Service

Sometimes it is necessary to know the cost per unit of delivered service (for example, cost per ton-hour of cooling), analogous to the cost per driven mile for cars. This can be calculated as a ratio of levelized annual cost and annual delivered service. The levelized annual cost is obtained by multiplying the life cycle cost by the capital recovery factor for discount rate and system life. There appear two possibilities: the real discount rate r_{d0} and the market discount rate r_d. The quantity $(A/P,r_{d0},N)\ C_{life}$ is the annual cost in constant dollars (of the initial year), whereas $(A/P,r_d,N)\ C_{life}$ is the annual cost in inflating dollars. The latter is difficult to interpret because it is an average over dollars of different real value. Therefore, we levelize with the real discount rate because it expresses everything in first year dollars, consistent with the currency of C_{life}. Thus, we write the annual cost in initial dollars as

$$A_{life} = (A/P,r_{d0},N)C_{life}. \tag{3.2.43}$$

The effective total cost per delivered service is therefore

$$\text{effective cost per energy} = A_{life}/Q \tag{3.2.44}$$

where Q = annual delivered service (assumed constant, for simplicity).

We do not simply divide C_{life} by the service N Q delivered by the system over its life time because that would not be consistent; C_{life} is the present value, while N Q contains service flows (and thus monetary values) that are associated with future times. One must allocate service flows and costs within the same time frame which is accomplished by dividing the levelized annual cost by the levelized annual service; the latter is equal to Q because we have assumed that the consumption is constant from year to year.

Example 13

What is the cost per ton-hour for the chiller of Example 12?

Given: C_{life} = 87.3 k$ and Q = 100 kton·h.

Find: A_{life}/Q.

Lookup values:

r_{d0} = 0.1058 from Equation 3.214

$(A/P, r_{d0}, N)$ = 0.1221 from Equation 3.2.13.

Solution

Levelized annual cost in first year dollars

$A_{life} = (A/P, r_{d0}, N)\ C_{life} = 0.1221 \times 87.3$ k$ = 10,659 $/yr.

Cost per ton-hour = A_{life}/Q = 0.107 $/ton·h.

Constant Currency Versus Inflating Currency

In the life cycle cost equation, all cost components have been converted to equivalent present values (i.e., first year costs). Let us see to what extent the result is the same whether one uses constant currency and real rates or inflating currency and market rates. In the term for energy cost only the variable $r_{d,e} = (r_d - r_e)/(1 + r_e)$ depends on this choice. Inserting real rates according to

$$(1 + r_{d0}) = \frac{1 + r_d}{1 + r_{inf}} \tag{3.2.45}$$

and

$$(1 + r_{e0}) = \frac{1 + r_e}{1 + r_{inf}}, \tag{3.2.46}$$

one finds that

$$r_{d,e} = \frac{(1 + r_{d0})(1 + r_{inf}) - (1 + r_{e0})(1 + r_{inf})}{(1 + r_{e0})(1 + r_{inf})}, \tag{3.2.47}$$

and after cancelling the factor $(1 + r_{inf})$, one sees that this is equal to

$$r_{d,e} = \frac{(1 + r_{d0}) - (1 + r_{e0})}{(1 + r_{e0})}. \tag{3.2.48}$$

The energy cost is the same, whether one uses real rates or market rates. The same holds for the maintenance cost term. The salvage term is also independent of this choice because

$$(1 + r_{inf})/(1 + r_d) = 1/(1 + r_{d0}).$$

By contrast, the ratio of capital recovery factors in the loan terms is not invariant, as one can see by inserting numerical values. For example, with $r_{d0} = 0.08$, $r_{l0} = 0.12$, and $r_{inf} = 0.05$ one finds, with N = 20 yr,

$$\frac{(A/P,r_{10},N)}{(A/P,r_{d0},N)} = 1.31 .$$

The corresponding market rates are $r_d = 0.134$ and $r_l = 0.176$, and the ratio becomes

$$\frac{(A/P,r_1,N)}{(A/P,r_d,N)} = 1.26 .$$

The difference arises from the fact that the cash flows are different. For a loan that is based on real rates, the annual payments are constant in constant currency, whereas for one based on market rates the payments are constant in inflating currency. Similarly, the depreciation terms can depend on inflation.

It follows that the two approaches, constant currency and inflating currency, yield identical results for equity investments ($f_l = 0$) without depreciation. But, if f_l or f_{dep} are not zero, there can be differences. Numerically the effect is not large, at most on the order of ten percent for inflation rates below ten percent [Dickinson and Brown, 1979]. The effect has opposite signs for the loan term and the depreciation term, leading to partial cancellation of the error.

3.2.4 Economic Evaluation Criteria

Life Cycle Savings

Having determined the life cycle cost of each relevant design alternative, one can select the "best," i.e., the one that offers all desirable features at the lowest life cycle cost. Frequently, one takes one design as reference and considers the difference between it and each alternative design. The difference is called *life cycle savings* relative to the reference case

$$S = -\Delta C_{life} \text{ with } \Delta C_{life} = C_{life} - C_{life,ref}. \tag{3.2.49}$$

Often the comparison can be quite simple because only those terms that are different between the designs need to be considered. For simplicity, we write the equations of this section only for an equity investment without tax. Then, the loan fraction f_l in Equation 3.2.42 is zero and most of the complications of that equation drop out. Of course, the concepts of life cycle savings, internal rate of return, and payback time are perfectly general, and tax and loan can readily be included.

A particularly important case is the comparison of two designs that differ only in capital cost and operating cost; the one that saves operating costs has higher initial cost (otherwise the choice would be obvious, without any need for an economic analysis). Setting f_l, τ_{cred}, C_{salv}, P_{max}, A_m, and $\tau = 0$ in Equation 3.2.42 and taking the difference between the two designs, one obtains the life cycle savings as

$$S = \frac{-\Delta Q p_e}{(A/P,r_{d,e},N)} - \Delta C_{cap} \tag{3.2.50}$$

where

$\Delta Q = Q - Q_{ref}$ = difference in annual energy consumption,
$\Delta C_{cap} = C_{cap} - C_{cap,ref}$ = difference in capital cost, and
$r_{d,e} = (r_d - r_e)/(1 + r_e)$.

(If the reference design has higher consumption and lower capital cost, ΔQ is negative, and ΔC_{cap} is positive with this choice of signs.)

Example 14

Compared to a one-stage model, a two-stage absorption chiller is more efficient, but its first cost is higher. Find the life cycle savings of a two-stage model for the followings situation.

Given:

Required chiller capacity 1000 kW_t,

operating at 1000 hours per year full load equivalent.

A single stage absorption chiller has COP = 0.7 and costs 100 $/$kW_t$ (reference system),

while a two-stage absorption chiller has COP = 1.1 and costs 130 $/$kW_t$.

gas price p_e = 4 $/GJ at the start,

escalating at r_e = 0% (real),

discount rate r_d = 8% (real).

Find:

Life cycle savings for the two-stage chiller.

Lookup value:

$(A/P,r_d,N) = 0.1019$.

Solution

The annual energy consumption is

$1000\ kW_t \times 1000\ hr/COP = 1.0\ MWh_t/COP$. This equals

$5.143 \times 10^3\ GJ_{gas}$ for COP = 0.7 and

$3.273 \times 10^3\ GJ_{gas}$ for COP = 1.1;

thus the difference in energy cost is

$\Delta Q\ p_e = (3.273 - 5.143) \times 10^3\ GJ \times 4\ \$/GJ = -\$7481$ per year;

the difference in capital cost is

$\Delta C_{cap} = (130 - 100) \times 1000 = \$30,000$

From Equation 3.2.50 we find the life cycle savings

$S = -\Delta Q\ p_e/(A/P,r_{d,e},N) - \Delta C_{cap}$

$= \$7481/0.1019 - 30,000 = \$73,415 - 30,000 = \$43,415.$

Comment:

Even though the discount rate in this example is rather high (5% might be more appropriate), the life cycle savings are large. The investment certainly pays off.

Internal Rate of Return

The life cycle savings are the true savings if all the input is known correctly and without doubt. But future energy prices or system performance are uncertain, and the choice of the discount rate is not clear cut. An investment in a building or its equipment is uncertain, and it must be compared with competing investments that have their own uncertainties. The limitation of the life cycle savings approach can be circumvented if one evaluates the profitability of an investment by itself, expressed as a dimensionless rate. Then one can rank different investments in terms of profitability and in terms of risk. General business experience can serve as a guide for expected profitability as a function of risk level. Among investments of comparable risk the choice can then be based on profitability.

More precisely, the profitability is measured as *internal rate of return* r_r, defined as that value of the discount rate r_d at which the life cycle savings S are zero:

$$S(r_d) = 0 \text{ at } r_d = r_r. \tag{3.2.51}$$

For an illustration, take the case of Equation 3.2.50 with energy escalation rate $r_e = 0$ (so that $r_{d,e} = r_d$), and suppose an extra investment ΔC_{cap} is made to provide annual energy savings $(-\Delta Q)$. The initial investment ΔC_{cap} provides an annual income from energy savings

$$\text{annual income} = (-\Delta Q)p_e. \tag{3.2.52}$$

If ΔC_{cap} were placed in a savings account instead, bearing interest at a rate r_r, the annual income would be

$$\text{annual income} = (A/P,r_r,N)\Delta C_{cap}. \tag{3.2.53}$$

The investment behaves like a savings account whose interest rate r_r is determined by the equation

$$(A/P,r_r,N)\Delta C_{cap} = (-\Delta Q)p_e. \tag{3.2.54}$$

Dividing by $(A/P,r_r,N)$, we see that the right and left sides correspond to the two terms in Equation 3.2.50 for the life cycle savings

$$S = \frac{-\Delta Q p_e}{(A/P,r_d,N)} - \Delta C_{cap}, \tag{3.2.55}$$

and that r_r is indeed the discount rate r_d for which the life cycle savings are zero; it is the internal rate of return. Now the reason for the name is clear — it is the profitability of the project by itself, without reference to an externally imposed discount rate. When the explicit form of the capital recovery factor is inserted, one obtains an equation of the Nth degree, generally not solvable in closed form. Instead, one resorts to an iterative or graphical solution. (There could be up to N different real solutions, and multiple solutions can indeed occur if there are sign changes in the stream of annual cash flows. However, not to worry, the solution is unique for the case of interest here; an initial investment that brings a stream of annual savings.)

Example 15

What is the rate of return for Example 14?

Given:

$$S = \frac{-\Delta Q p_e}{(A/P,r_{d,e},N)} - \Delta C_{cap},$$

with $r_{d,e} = r_d$ (because $r_e = 0$),

$(-\Delta Q)\ p_e = \$7481$, and

$\Delta C = \$30{,}000$.

Find: r_r

Solution

S = 0 for

$$(A/P,r_r,N) = \frac{-\Delta Q p_e}{\Delta C_{cap}}$$

$$= \frac{7481}{30,000} = 0.2494 \text{ with } N = 20.$$

By iteration one finds $r_r = 0.246 = 24.6\%$.

Payback Time

The *payback time* N_p is defined as the ratio of extra capital cost ΔC_{cap} to first year savings

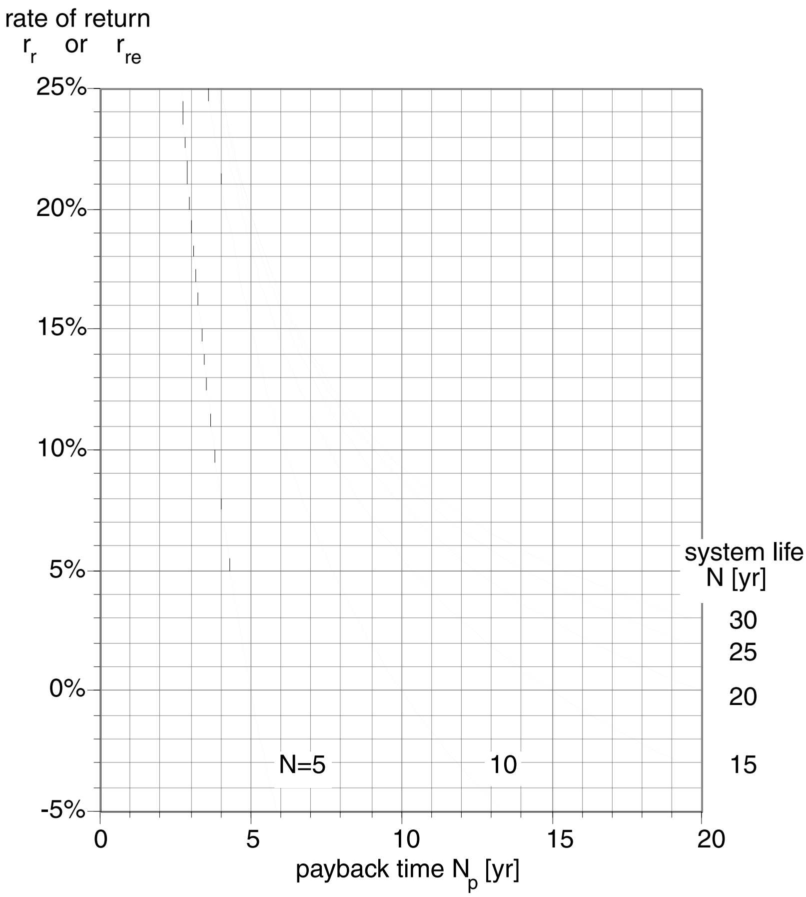

FIGURE 3.2.6 Relation between rate of return r_r, system life N, and payback time N_p. If r_e = escalation rate of annual savings, 0, the vertical axis is the variable $r_{r,e}$ from which r_r is obtained as $r_r = r_{r,e}(1 + r_e) + r_e$.

$$N_p = \frac{\Delta C_{cap}}{\text{first year savings}}. \tag{3.2.56}$$

(The inverse of N_p is sometimes called *return on investment.*) If one neglects discounting, one can say that after N_p years the investment has paid for itself, and any revenue thereafter is pure gain. The shorter N_p, the higher the profitability. As selection criterion, the payback time is simple, intuitive, and obviously wrong because it neglects some of the relevant variables. Attempts have been made to correct for that by constructing variants such as a discounted payback time (by contrast to which Equation 3.2.56 is sometimes called simple payback time), but the resulting expressions become so complicated that one might as well work directly with life cycle savings or internal rate of return.

The simplicity of the simple payback time is, however, irresistible. When investments are comparable to each other in terms of duration and function, the payback time can give an approximate ranking that is sometimes clear enough to discard certain alternatives right from the start, thus avoiding the effort of detailed evaluation.

To justify the use of the payback time, recall Equation 3.2.54 for the internal rate of return and note that it can be written in the form

$$(A/P,r_r,N) = 1/N_p, \quad \text{or} \quad (P/A,r_r,N) = N_p. \tag{3.2.57}$$

The rate of return is uniquely determined by the payback time N_p and the system life N. This equation implies a simple graphical solution for finding the rate of return if one plots $(P/A,r_r,N)$ on the x-axis versus r_r on the y-axis as in Figure 3.2.6. Given N and N_p, one simply looks for the intersection of the line $x = N_p$ (i.e., the vertical line through $x = N_p$) with the curve labeled by N; the ordinate (y-axis) of the intersection is the rate of return r_r.

This graphical method can be generalized to the case where the annual savings change at a constant rate r_e. In that case, Equation 3.2.20 implies that the rate of return is replaced by $r_{r,e} = (r_r - r_e)/(1 + r_e)$, and Figure 3.2.6 yields $r_{r,e}$ rather than r_r. In other words Equation 3.2.57 becomes

$$(P/A,r_{r,e},N) = N_p, \text{ with } r_{r,e} = (r_r - r_e)/(1 + r_e). \tag{3.2.58}$$

The graph yields $r_{r,e}$ which is readily solved for

$$r_r = r_{r,e}\,(1 + r_e) + r_e. \tag{3.2.59}$$

In particular, if r_e is equal to the general inflation rate r_{inf}, then $r_{r,e}$ is the real rate of return $r_{r,0}$.

Example 16

Find payback time for Example 15 and check rate of return graphically.

Given:

first year savings $(-\Delta Q)\ p_e = \$7481$,

extra investment $\Delta C_{cap} = \$30{,}000$.

Find:

N_p and r_r, for $r_e = 0$ and 2%.

Solution

$N_p = 30{,}000/7481 = 4.01$ yr;

it is independent of r_e.

Then $r_r = 0.246$ for $r_e = 0$, from Figure 3.2.6,

and $r_r = 0.271$ for $r_e = 2\%$, from Equation 3.2.58.

Generally a real (i.e., corrected for inflation) rate of return above 10% can be considered excellent if there is low risk — a look at savings accounts, bonds, and stocks shows that it is difficult to find better. From the graph we see immediately that $r_{r,e}$ is above 10% if the payback time is shorter than 8.5 yr (6 yr), for a system life of 20 yr (10 yr). And $r_{r,e}$ is close to the real rate of return if the annual savings growth is close to the general inflation rate.

3.2.5 Complications of the Decision Process

In practice, the decision process is likely to bump into some obstacles. Suppose, for example, that the annual operating cost of a proposed office building can be reduced by $1000 if one installs daylight sensors and dimmers for the lights, at an extra cost of $2000. The payback time is only 2 years. It looks like an irresistible investment opportunity, with a rate of return well above 25%, as shown by Figure 3.2.6 (the exact value depends somewhat on lifetime and taxes, but that is beside the point). However, quite a few hurdles stand in the way.

First, to find out about this opportunity, the design engineer has to obtain the necessary information. Requesting catalogs, reading technical reviews of the equipment, and carrying out the calculations of cost and performance all take time and effort. Under the pressures of the job, the engineer may not be willing to spend the extra time or neglect other items that compete for his attention.

Suppose our engineer has done a good analysis and tries to convince the builder to spend the extra money. In the case of a speculative office building, the builder is likely to say "why should I pay a penny more, if only the future tenant will reap the benefit?" So, the design engineer is forced to aim for lowest first cost.

Even if the builder is willing to spend a bit more for efficiency, with hopes that the prospect of reduced energy bills will make it easier to find tenants, the decision is not obvious. Can the builder trust the claims of the sales brochure or the calculations of the engineer? Daylight controls are relatively new, and perhaps the builder has heard that some of the first models did not live up to expectations. If malfunctions reduce the productivity of the workers, the hassle and the costs could nullify the expected savings. So the builder may refuse to take what he or she perceives as an excessive risk. The threat of a liability suit is a potent inhibitor; that is why the building industry has a reputation for extreme conservatism.

This example illustrates the basic mechanisms that frequently prevent the adoption of efficient technologies:

- Lack of information or excessive cost of obtaining the information
- Purchase decision made by someone who does not have to pay the operating costs
- Uncertainty (about future costs, reliability, etc.)

Any one of these hurdles can be sufficient to reject an investment. In the above example and decision to reject the lighting controller, it looks as if the discount rate was higher than 25%. Quite generally, these mechanisms have the effect of raising the apparent discount rate or foreshortening the time horizon. The resulting decisions appear irrational: people do not spend as much for energy efficiency as would be optimal according to a life cycle cost analysis with the correct discount rate. In reality, this irrationality is but a reflection of other problems.

In the world of business, risk and uncertainty are pervasive — so much so that most decision makers insist on very short payback times, almost always less than five years and frequently less than two. However, this decision depends on the business and circumstances. There are industries like electric power plants, where profits are sure (albeit moderate); once a power plant has been built it is expected to run smoothly for at least thirty years. Here the discounts rates are low and payback times are longer than ten years. Governments, charged with the long-term welfare of its citizens, also tend to have a long time horizon.

What does all this mean for the HVAC engineer? The more a design choice involves unproven technology or is dependent on occupant behavior for proper functioning, the more risky it is. For example, a daylighting strategy that relies on manual control of shading devices by the occupants may not bring the intended savings because the occupants may not follow the intentions of the designer. Likewise, when considering a new design or a new piece of equipment without a track record, it is not irrational to demand short payback times.

By contrast, paying extra for an efficient boiler or chiller is a safe investment (assuming the equipment has a good reputation) because the occupant does not care how the heating or cooling is produced as long as the environment is comfortable, pleasant, and healthy. Also, the building will certainly be heated and cooled over its entire life. Here a life cycle cost analysis with the correct discount rate is certainly in order, and it would be shortsighted to insist on payback times below two years.

Finally, what about the problem of the builder or landlord who refuses to pay for measures that would only reduce the energy bill of the tenant or of a future owner? This difficulty is serious, indeed. In an ideal market, the information about reduced energy cost would translate itself as higher rent or resale value, but, in practice, this process is slow and inefficient (there is a *market failure*, in the language of the economists). This situation justifies energy-efficiency standards such as the ASHRAE Standard 90.1 and their enforcement by government regulations.

3.2.6 Cost Estimation

Capital Costs

For mass produced consumer products, such as cars or cameras, the capital cost (i.e., the purchase price) is easy to determine by looking at catalogs or newspaper ads or by calling the store. Even then there may be uncertainties — when you actually go the store, a discount may be offered on the spot to beat a competitor. Different prices can be found in different stores for identical products, not only because of differences in service or transportation but also because of the sheer difficulty of obtaining the price information.

And, of course, price is not the only criterion. Even more important, and more difficult to ascertain and compare, are the various characteristics of a good: the features it offers, the quality, the operating costs, among others. Economists have even coined a special term, *cost of information*, which demonstrates how universal is the difficulty of finding the pertinent information.

For HVAC equipment, the problems tend to be more complicated than for consumer goods. Transport and installation are important items in addition to the cost of the equipment at the factory. The determination of the cost can become a major undertaking, especially for complex or custom made systems. The capital cost of a system or component is known with certainty only when one has a firm contract from a vendor. Asking for bids on each design variation, however, is simply not feasible — the cost of information would become prohibitive.

The more a design engineer wants to be sure of coming close to the optimal design, the more he or she needs to learn about the details of the cost calculation. Information on costs is available from a number of sources, for example Boehm (1987). An important feature is the variation of the cost with size. Because of fixed costs and economies of scale, simple proportionality between cost and size is not the rule. But usually one can assume the following functional form over a limited range of sizes

$$C = C_r\left(\frac{S}{S_r}\right)^m \quad \text{for} \quad S_{min} < S < S_{max} \tag{3.2.60}$$

where

C = cost at size S,

C_r = cost at a reference size S_r, and

m = exponent.

Typically, m is in the range of 0.5 to 1.0; exponents less than unity are a reflection of economies of scale. On a logarithmic plot, m is the slope of ln(C) versus ln(S). If m is not known, a value of 0.6 can be recommended as default. Table 3.2.A1 of the Appendix summarizes cost data for HVAC equipment in this form.

When interpreting such cost figures, one has to be careful about what is included and what is not. Is it the cost at the factory FOB (free on board, i.e., excluding transportation), the cost delivered to the site, or the cost installed? For items such as cool storage, the space requirements may impose additional costs. And finally, what are the specific features and how is the quality?

Costs change not only with general inflation but with the evolution of technology. The first models of a novel product tend to be expensive. Gradually, mass production, technological advance, and competition combine to drive the prices down. General inflation or increases in the cost of some input, for example energy, will push in the opposite direction. The resulting evolution of the price of the product may be difficult to predict. Cost reductions due to technological advance are more likely with products of high technology (e.g., energy management systems) than with mature products that cannot be miniaturized (e.g., fans and motors). In some cases, there is an improvement in a product rather than a reduction of its cost; variable speed motors, for instance, are more expensive than constant speed motors but allow better control or higher system efficiency.

Cost tabulations are based on sales or projects of the past, and they must be updated to the present by means of correction factors. For that purpose one could use general inflation (i.e., the CPI discussed in the earlier section on "The Effect of Time on the Value of Money"), but that is less reliable than specific cost indices for that class of equipment or that sector of the economy. The following two indices are particularly pertinent for buildings and HVAC equipment. One is the Marshall and Swift Equipment Cost Index, values of which are published regularly in *Chemical Engineering*. Another one is the construction cost index published by *Engineering News Record*, plotted in Figure 3.2.1(b).

It is important during the design process to have a realistic understanding of all the relevant costs, yet the effort of obtaining these costs should not be prohibitive. Konkel (1987) describes a method that seems to be a good compromise between these conflicting requirements. The basic idea is to group certain portions of a project into what is called *unit operations*. The components of the unit operations, called *unit assemblies*, are itemized, priced, and plotted by size of the unit operation. A boiler is an example of a unit operation; its unit assemblies include burner, air intake, flue, shutoff valves, piping, fuel supply, expansion tank, water makeup valves, and deaerator. Their sizes and costs vary with the size of the boiler. Once the size-price relations have been found for each component, the size-price relation for the boiler as a whole is readily derived. Knowing the size-price relation for the unit operations, the designer can estimate the total cost of a project and its design variations without too much effort.

Maintenance and Energy

Maintenance cost and energy prices may evolve differently from general inflation and from each other. It is instructive to correct energy prices for general inflation, as in Figure 3.2.2 where the prices of oil, gas, and electricity are shown in both current and constant dollars. One can see that some adjustments have occurred since the oil shocks of the 1970s.

What should we assume for the future? Projections of energy prices are published periodically by several organizations, for instance the American Gas Association and the National Institute of Standards and Technology (Lippiat and Ruegg, 1990). Most analysts predict real escalation rates in the range of 0 to 3%, averaged over the next two decades. This is based on the gradual exhaustion of cheap oil and gas reserves, and the fact that alternatives, i.e., coal, nuclear, and solar, are more expensive to utilize. Who knows? Further turmoil in the Middle East? What progress will be made in fusion and how will public acceptance of nuclear power evolve? How much can be saved by improved efficiency, and at what cost? What constraints will be imposed by environmental concerns?

Data on maintenance costs can be obtained, for example, from the *BOMA Experience Exchange Report* published annually by the Building Owners and Managers Association International (BOMA, 1987). Specifically for maintenance costs of HVAC equipment in office buildings, a succinct equation can be found in ASHRAE (1991). It states the annual cost A_M for maintenance, in dollars per floor area A_{floor}, in the form

$$\frac{A_M}{A_{floor}} = C_{base} + a\,n + h + c + d \qquad (3.2.61)$$

where

C_{base} = value for the base system (fire-tube boilers for heating, centrifugal chillers for cooling, and VAV for distribution, during first year),

n = age of equipment in years,

a = coefficient for age of equipment,

and the coefficients h, c, and d allow the adjustment to other systems.

TABLE 3.2.2 HVAC Maintenance Costs of Equation 3.2.61

	$/ft²	$/m²
$\mathbf{C_{base}}$	0.3335	3.590
Coefficient **a** for **age**/yr	0.0018	0.019
Heating Equipment, coefficient **h**		
Water-tube boiler	0.0077	0.083
Cast iron boiler	0.0094	0.101
Electric boiler	–0.0267	–0.287
Heat pump	–0.0969	–1.043
Electric resistance	–0.1330	–1.432
Cooling Equipment, coefficient **c**		
Reciprocating chiller	–0.0400	–0.431
Absorption chiller (single stage)	0.1925	2.072
Water source heat pump	–0.0472	–0.508
Distribution System, coefficient **d**		
Single zone	0.0829	0.892
Multizone	–0.0466	–0.502
Dual duct	–0.0029	–0.031
Constant volume	0.0881	0.948
Tow-pipe fan coil	–0.0277	–0.298
Four-pipe fan coil	0.0580	0.624
Induction	0.0682	0.734

Note: Cost C_{base} of base system and coefficients for adjustment. Units of dollars per floor area, 1983 U.S. dollars.
Source: Adapted from ASHRAE (1991).

Numerical values for C_{base}, a, h, c, and d are listed in Table 3.2.2. These values are 1983 dollars. They still need to be adjusted to the year of interest by multiplication by the corresponding ratio of CPI (consumer price index) values, as explained in Section 3.2.2. In using this equation one should keep in mind that it is based on a survey of office buildings originally published in 1986. Extrapolation to other building types or newer technologies may introduce large and unknown uncertainties.

Example 17

Estimate the annual HVAC maintenance cost for an office building that has floor area 1000 m² and is n = 10 yr old in the year 2003. The system consists of an electric boiler, a reciprocating chiller, and a constant volume distribution system. Suppose the CPI is 180 in 2003.

Given:

$A_{floor} = 1000\ m^2$,

$n = 10$ yr,

$CPC_{2003}/CPI_{1983} = 180/100 = 1.80$.

Lookup values:

From Table 3.2.2

$C_{base} = 3.59$, $a = 0.019$, $h = –0.287$, $c = –0.431$, $d = 0.948$ [in $\$_{1983}/m^2$].

Find: A_M

Solution

Using Equation 3.2.61

$A_M = 1000\ m^2 \times (3.59 + 0.019 \times 10 - 0.287 - 0.431 + 0.948)\ \$_{1983}/m^2 = 4010\ \$_{1983}/m^2$

To convert to $\$_{2003}$ multiply by the CPI ratio

$A_M = 4010\ \$_{1983}/m^2 \times 1.80 = 7218\ \$_{2003}/m^2$.

3.2.7 Optimization

In principle, the process of optimizing the design of a building is simple — evaluate all possible design variations and select the one with the lowest life cycle cost. Who would not want to choose the optimum? In practice, it would be a daunting task to find the true optimum among all conceivable designs. The difficulties, some of which have already been discussed, are

- The enormous number of possible design variations (building configuration and materials, HVAC systems, types and models of equipment, control modes)
- Uncertainties (costs, energy prices, reliability, occupant behavior, future uses of building)
- Imponderables (comfort, convenience, aesthetics)

Fortunately, there is a certain tolerance for moderate errors, as we show below, which facilitates the job greatly because one can reduce the number of steps in the search for the optimum. Also, within narrow ranges, some variables can be suboptimized without worrying about their effect on others.

Some quantities are easier to optimize than others. Optimizing the heating and cooling equipment, for a given building envelope, is less problematic than trying to optimize the envelope — the latter touches on the imponderables of aesthetics and image.

It is instructive to illustrate the optimization process with a very simple example: the thickness of insulation on a wall. The annual heat flow Q across the insulation is

$$Q = A\,k\,D/t \tag{3.2.62}$$

where

A = area [m^2],
k = conductivity [W/m·K],
D = annual degree-seconds [K·s], and
t = thickness of insulation [m].

The capital cost of the insulation is

$$C_{cap} = A\,t\,p_{ins} \tag{3.2.63}$$

with p_{ins} = price of insulation [\$/m^3].

The life cycle cost is

$$C_{life} = C_{cap} + Q\frac{p_e}{(A/P, r_{d,e}, N)} \tag{3.2.64}$$

where p_e = first year energy price, and $r_{d,e}$ is related to discount rate and energy escalation rate as in Equation 3.2.19. We want to vary the thickness t to minimize the life cycle cost, keeping all the other quantities constant. (This model is a simplification that neglects fixed cost of insulation as well as possible feedback of t on D.) Eliminating t in favor of C_{cap}, one can rewrite Q as

$$Q = K/C_{cap} \tag{3.2.65}$$

with a constant

$$K = A^2\,k\,D\,p_{ins}. \tag{3.2.66}$$

Then the life cycle cost can be written in the form

$$C_{life} = C_{cap} + P\,K/C_{cap} \tag{3.2.67}$$

where the variable

$$P = \frac{p_e}{(A/P, r_{d,e}, N)} \tag{3.2.68}$$

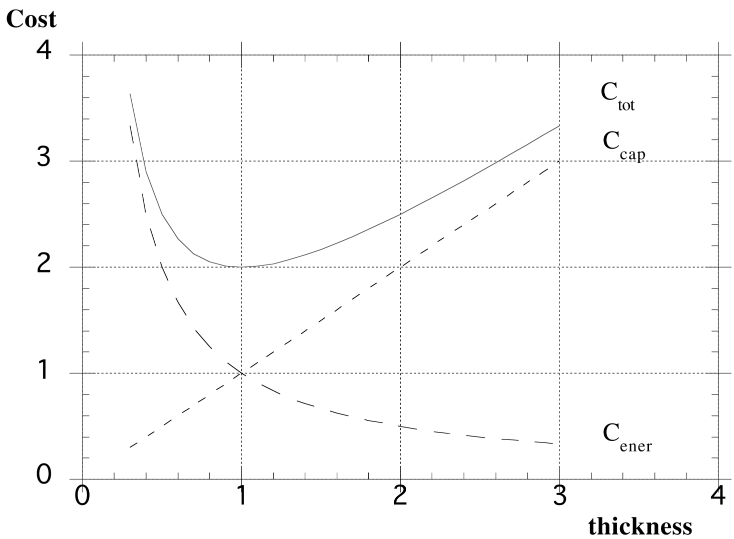

FIGURE 3.2.7 Optimization of insulation thickness. Insulation cost = C_{cap}, energy cost = C_{ener}, life cycle cost = C_{tot}.

contains all the information about energy price and discount rate. K is fixed, and the insulation investment C_{cap} is to be varied to find the optimum. C_{life} and its components are plotted in Figure 3.2.7. As t is increased, capital cost increases, energy cost decreases; C_{life} has a minimum at some intermediate value. Setting the derivative of C_{life} with respect to C_{cap} equal to zero yields the optimal value C_{cap0}

$$C_{cap0} = \sqrt{K\,P}\,. \tag{3.2.69}$$

Now an interesting question: what is the penalty for not optimizing correctly? In general, the following causes could prevent correct optimization:

- Insufficient accuracy of the algorithm or program for calculating the performance
- Incorrect information on economic data (e.g., the factor P in Equation 3.2.69)
- Incorrect information on technical data (e.g., the factor K in Equation 3.2.69)
- Unanticipated changes in the use of the building

Misoptimization would produce a design at a value C_{cap} different from the true optimum C_{cap0}. For the example of insulation thickness, the effect on the life cycle cost can be seen directly with the solid curve in Figure 3.2.7. For example, a ±10% error in C_{cap0} would increase C_{life} by only +1%. Thus, the penalty is not excessive for small errors.

This relatively large insensitivity to misoptimization is a feature much more general than the insulation model. As shown by Rabl (1985), the greatest sensitivity likely to be encountered in practice corresponds to the curve

$$\frac{C_{life,true}\left(C_{cap0,guess}\right)}{C_{life,true}\left(C_{cap0,true}\right)} = \frac{x}{1+\log(x)}, \quad (\text{“upper bound”}) \tag{3.2.70}$$

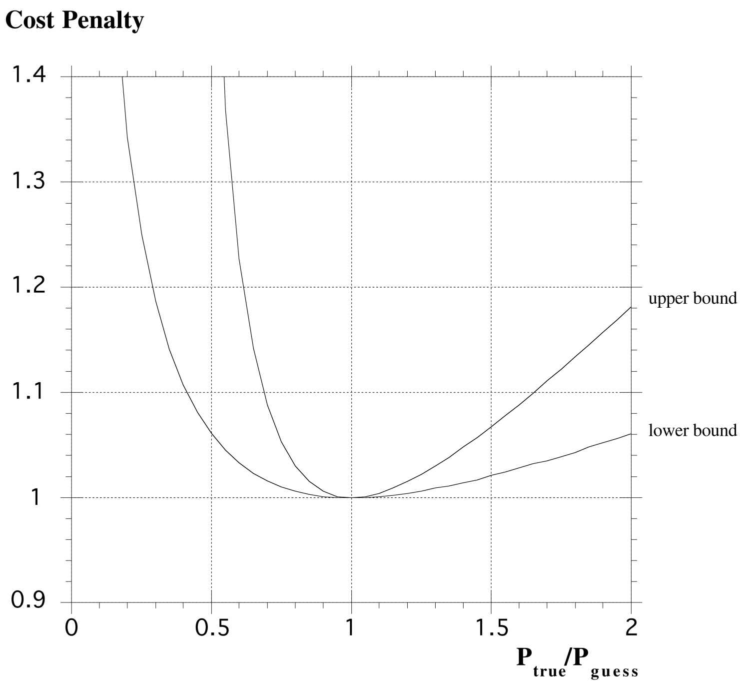

FIGURE 3.2.8 Life cycle cost penalty versus energy price ratio.

also shown in Figure 3.2.8, with the label “upper bound.” Even here the minimum is broad; if the true energy price differs by ±10% from the guessed price, the life cycle cost increases only 0.4% (0.6%) over the minimum. Even when the difference in prices is 30%, the life cycle cost penalty is less than 8%.

Errors in the factor K (due to wrong information about price or conductivity of the insulation material) can be treated the same way because K and P play an entirely symmetric role in the above equations. Therefore, curves in Figure 3.2.8 also apply to uncertainties in other input variables.

The basic phenomenon is universal: any smooth function is flat at an extremum. The only question is how flat. For energy investments, that question has been answered with the curves of Figures 3.2.7 and 3.2.8. We can conclude that misoptimization penalties are definitely less then 1% (10%), when the uncertainties of the input variables are less than 10% (30%).

Nomenclature

A	annual payment
$\mathbf{A_{life}}$	levelized annual cost
$\mathbf{A_M}$	annual cost for maintenance [in first year $]
(A/P,r,N)	capital recovery factor
C	cost at size S
$\mathbf{C_{cap}}$	capital cost [in first year $]
$\mathbf{C_{life}}$	life cycle cost

CPI	consumer price index
$\mathbf{C_r}$	cost at a reference size S_r
$\mathbf{C_{salv}}$	salvage value [in first year $]
$\mathbf{f_{dep}}$	present value of total depreciation, as fraction of C_{cap}
$\mathbf{f_{dep,n}}$	depreciation during year n, as fraction of C_{cap}
$\mathbf{f_l}$	fraction of investment paid by loan
$\mathbf{I_n}$	interest payment during nth year
L	loan amount
m	exponent of relation between cost and size of equipment
N	system life [yr]
n	year
$\mathbf{N_2}$	doubling time
$\mathbf{N_{dep}}$	depreciation period [yr]
$\mathbf{N_p}$	payback time [yr]
$\mathbf{N_l}$	loan period [yr]
$\underline{\mathbf{p}}_\mathbf{e}$	energy price
$\boldsymbol{p_e}$	levelized energy price
(P/F,r,n)	present worth factor
$\mathbf{p_{dem}}$	demand charge [$/kW·month]
$\mathbf{p_{ins}}$	price of insulation [$/m^3]
$\mathbf{P_{int}}$	present value of interest payments
$\mathbf{P_{max}}$	peak demand [kW]
$\mathbf{P_n}$	principal during nth payment period n
$\mathbf{r_0}$	$(r - r_{inf})/(1 + r_{inf})$
$\mathbf{r_d}$	market discount rate
$\mathbf{r_{d,e}}$	$(r_d - r_e)/(1 + r_e)$
$\mathbf{r_{d,l}}$	$(r_d - r_l)/(1 + r_l)$
$\mathbf{r_{d,M}}$	$(r_d - r_M)/(1 + r_M)$
$\mathbf{r_{dif}(\omega_{ss},\omega)}$	I_{dif}/H_{dif}
$\mathbf{r_e}$	market energy price escalation rate
$\mathbf{r_{inf}}$	general inflation rate
$\mathbf{r_l}$	market loan interest rate
$\mathbf{r_M}$	market escalation rate for maintenance costs
$\mathbf{r_r}$	internal rate of return
S	life cycle savings (= $-C_{life} + C_{life,ref}$)
S	size of equipment
s	annual savings
t	thickness of insulation [m]
τ	incremental tax rate
$\tau_{\mathbf{cred}}$	tax credit

The subscript $_0$ designates real growth rates r_0, related to the corresponding nominal (or market) rates r by $1 + r_{ann} = \exp(r_{cont})$. The subscript $_{ann}$ designates annual growth rates, related to the corresponding continuous rates (with subscript $_{cont}$).

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Appendix

TABLE 3.2.A1 Typical Equipment Cost C as Function of Size S, in the Form $C = C_r\ (S/S_r)^m$

Component or System Description	*m*	C_r[k$]	S_r	*S Range*, Units
Pumps, Fans, Blowers, and Compressors				
Pump, centrifugal, horizontal, 50 ft head,	0.26	2	10	0.2↔16 kW
ci, radial flow, no motor. FOB.	0.43	5.3	100	16↔400 kW
	0.34	3.2	0.5	0.05↔30 m^3/min
Pump, same as above but with motor.	0.39	2.5	10	1↔23 kW
	0.58	7.5	100	23↔250 kW
	0.59	4.3	1	0.04↔30 m^3/min
Pump, positive displacement, P_{in} = 150 psi, P_{out} <1000 psi, no motor, gears. ci. FOB. (P_{out} =5000 ↔ 10000 psi, ×2.5).	0.52	4	10	1↔70 kW
Fan, centrifugal, radial bladed, 2.5 kPa,				
del., no motor.	0.78	5.3	10	2↔100 m^3/s
del., with motor.	0.93	9.3	10	2↔50 m^3/s
Fan, propeller with motor. FOB.	0.58	0.45	1	0.5↔6 m^3/s
	0.36	1.5	10	6↔50 m^3/s
Blower, centrifugal, 28 kPa, del., no motor.	0.61	160	30	12↔70 m^3/s
With motor, drive: 1.6 × (no motor cost).				
Blower, rotary sliding vane, 275 kPa, del., no drive.	0.4	9.9	0.1	0.01↔0.4 m^3/s
Compressor, centrifugal, <7000 kPa, del., with electric motor.	0.9	450	10^3	2↔4000 kW
Compressor, same as above, but no motor. FOB.	0.53	290	10^3	(5↔40) × 10^2 kW
exit pressure (MPa) factors: 1.7, × 8; 6.9, ×1; 14, ×1.15; 34, ×1.4; 48, ×1.5				
Electrical motors, AC, enclosed, fan cooled.	0.68	0.67	10	1↔10 HP
Other types	0.87	0.67	10	10↔1000 HP
Heat Exchangers (Costs can vary tremendously with material and flow design)				
Shell and tube, 150 psi., floating head, cs, 16 ft long, del.	0.71	21	100	2↔2000 m^2
Factors: 400 psi, ×1.25; 1000 psi, ×1.55; 3000 psi, ×2.5; 5000 psi, ×3.1.				
Plate and frame, CS frame, 304ss plates.	0.78	0.1	1	100↔5000 ft^2
Air cooler, finned tube, cs, 150 psi, includes motor and fan. FOB.	0.8	70	280	20↔2000 m^2
Heat recovery unit, for engine/generator.	0.45	0.95	1	200↔1500 kW
O&M costs=$0.67/kWh.				
Heat recovery unit, water and firetube boilers (flue gas flow, scf/h).	0.75	110	200	30↔2000 scf/hr
Immersion heater, electric, FOB.	0.87	1.9	50	10↔200 kW
Cooling tower, induced or forced draft, approach temp.=5.5°C,	1.0	70	10	4↔60 m^3/min
wet-bulb temp.=23.8°C, range=5.5°C, directly installed, all costs except foundations, water pumps, and distribution pipes.				
	0.64	560	100	60↔700 m^3/min
In terms of cooling capacity	1.0	72	3.6 × 10^3	10^3↔10^4 kW

Factors to correct to other conditions: approach *T*, °C	Wet-bulb *T*, °C	Cooling range, °C
2.75, ×1.50	10, ×1.92	3, ×0.78
4, ×1.22	15, ×1.43	5, ×0.92
7, ×0.85	20, ×1.14	10, ×1.3
11, ×0.49	25, ×0.95	15, ×1.62
14, ×0.39	32, ×0.66	22, ×1.93

incl. foundations and basin × 1.7 to 3.0.				
*Water distribution to and from cooling tower, installed.	0.7	160	1	0.1↔2 m^3/s
*Water treatment. Demineralizing, ion exchange, input 1330 ppm, output 30–40 ppm solids, installed. (FOB, ×0.7)	1.0	3200	0.1	0.0004↔0.8 m^3/s
Factors to correct to other conditions: inlet feed: 1000 ppm, ×0.5; 500 ppm, ×0.25; 200 ppm, ×0.18;100 ppm, ×0.13				
*Steam deaerator, cs, FOB.	0.78	67	1	(0.05↔40) ×10^5 kg/hr

TABLE 3.2.A1 (*continued*) Typical Equipment Cost C as Function of Size S, in the Form $C = C_r\ (S/S_r)^m$

Component or System Description	*m*	C_r[k$]	S_r	*S Range*, Units
		Furnaces, Boilers, Heaters		
Firetube package boiler, FOB.	0.59	40	200	40↔800 HP
Stoker, economizer, dust collectors.	0.37	170	5000	(2↔10) ×10^3 lb/hr
	0.56	500	25000	(1↔5) × 10^4 lb/hr
Gas fired, del., 50–200 psi sat. steam.	0.64	16	10^3	(0.2↔10) × 10^3 kg/hr
Water tube, FOB.	0.67	340	12	(4↔40) ↔ 10^4 lb/hr
Water heaters				
Gas-fired tank, FOB.	1.1	0.26	40	30 ↔ 100 gal
Electric heated tank, FOB.	1.0	0.26	50	30 ↔ 100 gal
Electric immersion, without tank, FOB.	0.87	1.3	50	10 ↔ 200 kW
Electric resistance heaters				
For household heating, cost = $550 + $40/kW.				
Waste heat steam boiler, unfired, 150 psi, del.	0.81	160	10¢	(0.1↔10) × 10^4 kg/hr
Box-type furnace, 500 psi, cs, del.	0.75	144	12	10 ↔ 400 kW
		Refrigerating Systems, Heat Pumps		
Air conditioners, Room, FOB.	0.8	1.2	2	0.33 ↔15 tons
Room, totally installed.	0.83	2.2	2	0.5 ↔15 tons
Maintenance costs, $/year.	0.38	0.2	2	0.33 ↔10 tons
Central chillers, vapor compression				
Reciprocating package, FOB.	0.5	13.6	50	10↔185 tons
Roof reciprocating, air-cooled condensor, FOB.	0.71	19.5	50	20↔85 tons
Centrifugal or screw compressor, FOB.	0.66	92	500	80↔2000 tons
O&M annual costs, reciprocating.	0.77	2	50	10↔185 tons
O&M annual costs, centrifugal or screw.	0.42	8	500	105↔2000 tons
Central chillers, LiBr absorption				
Single effect, installed.	0.66	160	500	100↔1400 tons
Double effect, installed.	0.7	230	500	400↔1200 tons
O&M, single or double effect, per year.	0.56	5.8	500	100↔1400 tons
Air-to-air heat pumps				
Equipment only.	0.86	2.4	3	1↔50 tons
Installed.	0.9	4.9	3	1↔50 tons
O&M per year.	0.5	0.3	3	1↔50 tons
Water-to-air heat pumps				
Equipment only.	0.64	1.65	3	1↔25 tons
Installed.	0.69	3.4	3	1↔25 tons
Maintenance, years 2–5.	0.5	0.3	3	1↔25 tons
		Miscellaneous		
Storage tanks				
Vertical steel field erected tanks.	0.68	0.017	1	10^3↔10^5 gal
Carbon steel.	0.56	1.4	100	100↔10^5 gal
Large volume cs, floating roof.	0.78	385	2 × 10^6	(2↔10) × 10^6 gal
Generally:				
Concrete $0.75-0.90/gal.				
Fiberglass $1.50/gal for 2000 gal size.				
Pipe type $1.00/gal.				
Pipe insulation (contractor price)				
Elastomer 3/4-in. thickness, $0.52/ft.				
Phenolic foam 1-in. thickness; $1.10/ft.				
Fiberglass 1-in. thickness, $0.70/ ft.				
Urethane $1.00/ft.				
Rule of thumb 10% of total mechanical costs.				

Notes: All costs adjusted for M&S index = 800. For fans and blowers, flow is in normal m3/s (at 0°C and 1.0 bar). Abbreviations used: ci=cast iron; cs=carbon steel; ss=stainless steel; m^3/min denotes cubic meters per minute of feed flow; del.=delivered; sat.=saturated; S_r = Reference size, in same units as *S Range* values.

Source: Extracted from Appendix D of Boehm (1987) to which the reader is referred for further detail and references.

* Additional option.