

Economics of Traditional Planning Methods

1 Introduction

These notes are partly adaptations of information from four sources in the bibliography [1], [2], [3, ch. 5], and the report [4], with some information obtained from a few other sources also listed in the bibliography. These sources provide an excellent treatment of traditional electric utility economic planning procedures. In spite of the fact that the electric utility industry has changed significantly since the development of some of this material, the principles outlined are still heavily used in planning done by regulated utilities.

The implicit assumption of material treated in these notes is that the planner has become aware that future operation of the existing system has non-negligible potential to result in violation of electric reliability criteria or undesirably high costs (including “costs” associated with lost opportunities). Therefore it is of interest to identify possible alternative decision paths that can be taken.

So the objective of economic analysis is to determine the economic consequences of project alternatives so that management can make an informed decision in selecting the most desirable alternative.

Two issues always important in planning decisions are

1. What is the investment cost of each alternative?
2. How is annual operational cost impacted by each alternative?

2 Types of expenditures

Expenditures incurred on a project can be divided into two types: (i) capital investments; (ii) operation & maintenance (O&M) expenses; i.e., *investments* and *expenses*.

Investment is the amount of money required to purchase or construct an asset having a service life beyond a year.

An expense is the amount of money required to own, operate, and maintain existing assets and also includes the amount of money required to purchase or construct assets having a service life of one year or less. Expenses may be categorized into three forms, as illustrated in Figure 2-1 [3] and summarized below.

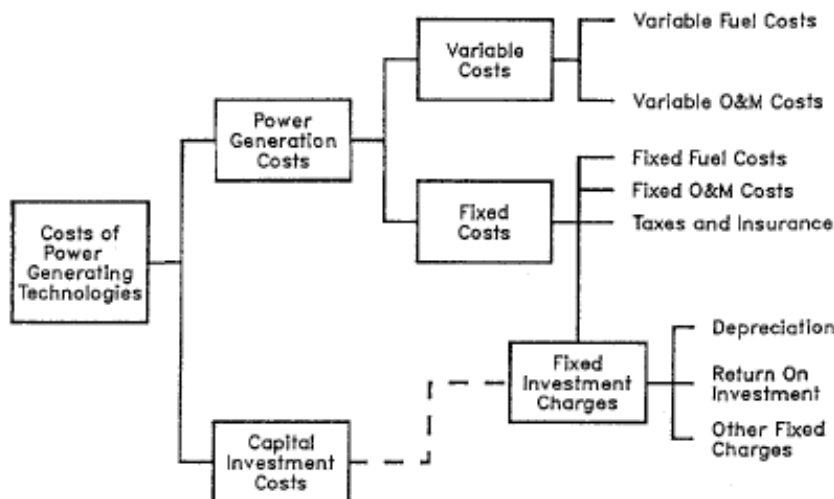


Figure 2-1: breakdown of expenses

1. Variable costs are generally divided into two parts:
 - a. Variable fuel costs (for generation facilities)
 - b. Variable O&M (VOM): includes non-fuel costs that are a function of production, e.g.,

- i. cost of repair and replacement;
 - ii. disposal of residuals and auxiliary materials (e.g., water, lubricants, fuel additives).
- 2. Non-investment fixed costs includes four parts:
 - a. fixed fuel costs (for generation facilities) such as the cost of storing fuel;
 - b. fixed O&M costs (salaries, scheduled maintenance);
 - c. ad valorem (property) tax: Tax levied on the basis of property values and paid to local jurisdictions such as county governments or school districts;
 - d. insurance: the costs of premiums for insurance policies or expenses of self-insurance programs.
- 3. Investment costs are related to the amount of capital invested in the asset. These are typically broken down into three kinds of fixed costs:
 - a. Cost of capital (return on investment): The return to the stockholders helping to finance the project, or the interest on bonds used to finance the project. (stockholders are owners; bondholders are lenders) or to the bank who lends the money.
 - b. Depreciation: This captures the fact that all facilities decrease in worth over time as they wear out. There are various methods of computing depreciation. Some of them are as follows:
 - i. Straight-line method (simplest): Here, for a facility with book life of N years, the annual depreciation is

$$\text{Year } k \text{ Depreciation} = (1/N) * (\text{Initial Value} - \text{Salvage Value})$$
 - ii. Double-declining balance: This method computes the depreciation, for each year k , as twice the annualized remaining value at year k , i.e.,

$$\text{Year } k \text{ Depreciation} = 2 * (1/N_k) * (\text{Current Value} - \text{Salvage Value})$$

where the current value is the initial value less the sum of all previous years' depreciation.

iii. Units of production: This method depreciates each year based on how much it produces, i.e.,

$$\text{Year } k \text{ Depreciation} = (P_k / P_{\text{Life}}) * (\text{Initial Value} - \text{Salvage Value})$$

where P_k are the units of production in year k , and P_{Life} are the lifetime units of production.

There are other methods, but these three offer three different perspectives on annual depreciation:

- it is constant (straight line);
- it is more at the beginning of life and less towards the end of life (double declining balance);
- it depends on use (units of production).

Figure 2-2 compares variation in annual depreciation for the three methods.

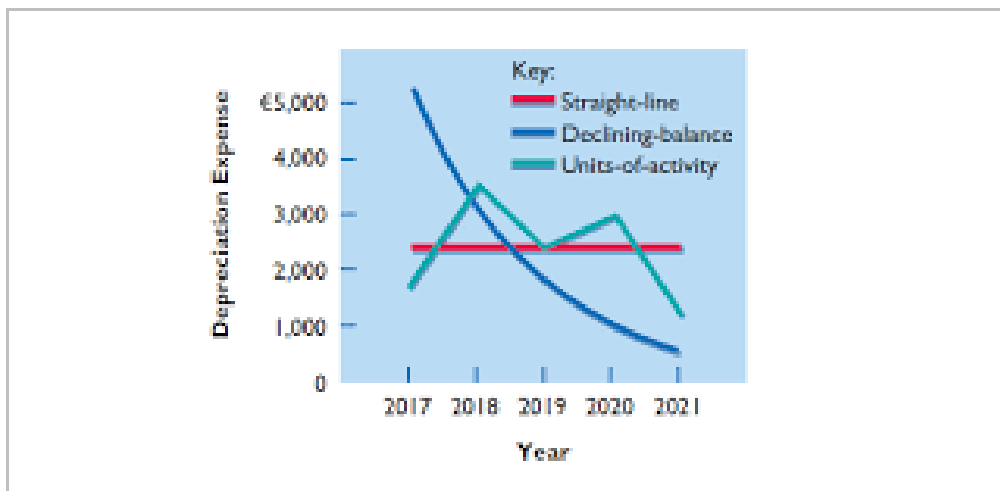


Figure 2-2: Comparing annual depreciation for 3 methods

c. Federal and state income taxes: Taxes levied on the basis of income, paid to federal and state governments (this may also be included as an operating expense). A

good summary of tax policy for rate-regulated utilities is given in [5]).

The above fixed charges (investment costs and non-investment fixed costs) are often captured in total using the so-called “fixed charge rate” (FCR) also known as “capital charge rate.”

The fixed charge rate is the fixed charges for one year as a percentage of the initial investment (overnight) cost. Note that the word “fixed” does not imply the amount is constant but rather implies the amount captures the “fixed” (as opposed to “variable” or those depending on production) costs. But fixed charges can be non-levelized or levelized.

Non-levelized (actual, annual) fixed charge rates have an annual variation that might begin at 28%/year and decrease to a value of 14%/year at age 30 years as interest and possibly depreciation decrease.

Fixed costs may also be levelized (we will see how to levelized cash flows in Section 4), resulting in a constant fixed charge rate over the facility life. Such fixed charges typically range from 18-22%/year. They may be obtained by (1) computing the present worth of all fixed charges over the life of the plant, and then (2) using the capital recovery factor to obtain the equivalent annuity over the facility life (again, we review these calculations in Section 4).¹

¹ The present worth calculation of step (1) should either use real dollars and real discount rate, or current dollars and nominal discount rate (the numerical result will be the same, either way). The annualization of step (2) can use the real discount rate, in which case the FCR is a “real dollar” percentage of the overnight charges (and reflects inflation), or it can use the nominal discount rate, in which case it is a “nominal dollar” percentage of the overnight changes (and does not reflect inflation). We further discuss real and nominal discount rates, and real and nominal dollars, later in these notes.

Detailed computation of each of the above components of the fixed charge rate is outlined in [2, pp. 58-64].

We compute the levelized FCR as follows:

$$\text{FCR} = \text{Annualized Fixed Charges} / \text{Overnight Cost}$$

where the overnight cost for various generation technologies are given in the following tables [6] (the first is from 2013; the other two are from 2019 and 2013 – it is interesting to observe how overnight costs for some technologies change).

Table 2-1: Generation costs from 2013

Technology	Online Year ¹	Size (MW)	Lead time (years)	Base Overnight Cost in 2014 (2013 \$/kW)	Project Contingency Factor ²	Technological Optimism Factor ³	Total Overnight Cost in 2014 ⁴ (2013 \$/kW)	Variable O&M ⁵ (2013 \$/mWh)	Fixed O&M (2013 \$/kW/yr.)	Heatrate ⁶ in 2014 (Btu/kWh)
Scrubbed Coal New	2018	1300	4	2,726	1.07	1.00	2,917	4.47	31.16	8,800
Coal-Gasification Integrated Comb Cycle (IGCC)	2018	1200	4	3,483	1.07	1.00	3,727	7.22	51.37	8,700
IGCC with Carbon sequestration	2018	520	4	5,891	1.07	1.03	6,492	8.44	72.80	10,700
Conv Gas/Oil Comb Cycle	2017	620	3	869	1.05	1.00	912	3.60	13.16	7,050
Adv Gas/Oil Comb Cycle (CC)	2017	400	3	942	1.08	1.00	1,017	3.27	15.36	6,430
Adv CC with Carbon sequestration	2017	340	3	1,845	1.08	1.04	2,072	6.78	31.77	7,525
Conv Comb Turbine ⁸	2016	85	2	922	1.05	1.00	968	15.44	7.34	10,783
Adv Comb Turbine	2016	210	2	639	1.05	1.00	671	10.37	7.04	9,750
Fuel Cells	2017	10	3	6,042	1.05	1.10	6,978	42.97	0.00	9,500
Adv Nuclear	2022	2234	6	4,646	1.10	1.05	5,366	2.14	93.23	10,479
Distributed Generation-Base	2017	2	3	1,407	1.05	1.00	1,477	7.75	17.44	9,015
Distributed Generation - Peak	2016	1	2	1,689	1.05	1.00	1,774	7.75	17.44	10,015
Biomass	2018	50	4	3,399	1.07	1.01	3,659	5.26	105.58	13,500
Geothermal ^{7,9}	2018	50	4	2,331	1.05	1.00	2,448	0.00	112.85	9,516
Municipal Solid Waste Conventional	2017	50	3	7,730	1.07	1.00	8,271	8.74	392.60	14,878
Hydropower ⁹	2018	500	4	2,410	1.10	1.00	2,651	5.76	15.15	9,516
Wind	2017	100	3	1,850	1.07	1.00	1,980	0.00	39.53	9,516
Wind Offshore	2018	400	4	4,476	1.10	1.25	6,154	0.00	73.96	9,516
Solar Thermal ⁷	2017	100	3	3,787	1.07	1.00	4,052	0.00	67.23	9,516
Photovoltaic ^{7,10}	2016	150	2	3,123	1.05	1.00	3,279	0.00	24.68	9,516

Compare the 2013 overnight costs (above) to that of the 2019 and 2023 costs (below). Although there are many interesting features to compare here, we highlight only two:

1. Offshore & onshore wind: Offshore is much higher than onshore. Overnight costs for both decrease from 2013→2019 (maturation, low

inflation); increase from 2019→2023 (maturation, high inflation). Yet, the *ratio* of offshore to onshore increases from 3.1 in 2013 to 4.1 in 2019 & decreases to 3.2 in 2023. The first change is due to the impact of much greater usage (and opportunity to improve) onshore; The reason for 2nd change is unclear.

- Also note cost decrease in solar PV from \$3279/kW (2013)→\$1331/kW (2019)→\$1448 (2023). The small 2023 increase is combined effect of maturation & inflation.

Table 2-2: Generation costs from 2019

Technology	First available year ¹	Size (MW)	Lead time (years)	Base overnight cost ² (2019 \$/kW)	Techno-logical optimism factor ³	Total overnight cost ^{4,5} (2019 \$/kW)	Variable O&M ⁶ (2019 \$/MWh)	Fixed O&M (2019\$/kW-yr)	Heat rate ⁷ (Btu/kWh)
Ultra-supercritical coal (USC)	2023	650	4	3,661	1.00	3,661	4.48	40.41	8,638
USC with 30% carbon capture and sequestration (CCS)	2023	650	4	4,539	1.03	4,652	7.05	54.07	9,751
USC with 90% CCS	2023	650	4	5,851	1.03	5,997	10.93	59.29	12,507
Combined-cycle—single shaft	2022	418	3	1,079	1.00	1,079	2.54	14.04	6,431
Combined-cycle—multi shaft	2022	1,083	3	954	1.00	954	1.86	12.15	6,370
Combined-cycle with 90% CCS	2022	377	3	2,470	1.04	2,569	5.82	27.48	7,124
Internal combustion engine	2021	21	2	1,802	1.00	1,802	5.67	35.01	8,295
Combustion turbine— aeroderivative ⁸	2021	105	2	1,170	1.00	1,170	4.68	16.23	9,124
Combustion turbine—industrial frame	2021	237	2	710	1.00	710	4.48	6.97	9,905
Fuel cells	2022	10	3	6,671	1.10	7,339	0.59	30.65	6,469
Advanced nuclear	2025	2,156	6	6,016	1.05	6,317	2.36	121.13	10,461
Distributed generation—base	2022	2	3	1,555	1.00	1,555	8.57	19.28	8,946
Distributed generation—peak	2021	1	2	1,868	1.00	1,868	8.57	19.28	9,934
Battery storage	2020	50	1	1,383	1.00	1,383	0.00	24.70	NA
Biomass	2023	50	4	4,080	1.01	4,104	4.81	125.19	13,500
Geothermal ^{9,10}	2023	50	4	2,680	1.00	2,680	1.16	113.29	9,156
Municipal solid waste—landfill gas	2022	36	3	1,557	1.00	1,557	6.17	20.02	8,513
Conventional hydropower ¹⁰	2023	100	4	2,752	1.00	2,752	1.39	41.63	NA
Wind ⁵	2022	200	3	1,319	1.00	1,319	0.00	26.22	NA
Wind offshore ⁹	2023	400	4	4,356	1.25	5,446	0.00	109.54	NA
Solar thermal ⁹	2022	115	3	7,191	1.00	7,191	0.00	85.03	NA
Solar photovoltaic —tracking ^{5,9,11}	2021	150	2	1,331	1.00	1,331	0.00	15.19	NA

Table 2-3: Generation costs from 2023

Technology	First available year ^a	Size (MW)	Lead time (years)	Base overnight cost ^b (2022\$/kW)	Techno-logical optimism factor ^c	Total overnight cost ^{d,e} (2022\$/kW)	Variable O&M ^f (2022\$/MWh)	Fixed O&M (2022\$/kW)	Heat rate ^g (Btu/kWh)
Ultra-supercritical coal (USC)	2026	650	4	\$4,507	1.00	\$4,507	\$5.06	\$45.68	8,638
USC with 30% carbon capture and sequestration (CCS)	2026	650	4	\$5,577	1.01	\$5,633	\$7.97	\$61.11	9,751
USC with 90% CCS	2026	650	4	\$7,176	1.02	\$7,319	\$12.35	\$67.02	12,507
Combined-cycle—single-shaft	2025	418	3	\$1,330	1.00	\$1,330	\$2.87	\$15.87	6,431
Combined-cycle—multi-shaft	2025	1,083	3	\$1,176	1.00	\$1,176	\$2.10	\$13.73	6,370
Combined-cycle with 90% CCS	2025	377	3	\$3,019	1.04	\$3,140	\$6.57	\$31.06	7,124
Internal combustion engine	2024	21	2	\$2,240	1.00	\$2,240	\$6.40	\$39.57	8,295
Combustion turbine—aeroderivative ^h	2024	105	2	\$1,428	1.00	\$1,428	\$5.29	\$18.35	9,124
Combustion turbine—industrial frame	2024	237	2	\$867	1.00	\$867	\$5.06	\$7.88	9,905
Fuel cells	2025	10	3	\$6,771	1.08	\$7,291	\$0.66	\$34.65	6,469
Nuclear—light water reactor	2028	2,156	6	\$7,406	1.05	\$7,777	\$2.67	\$136.91	10,447
Nuclear—small modular reactor	2028	600	6	\$7,590	1.10	\$8,349	\$3.38	\$106.92	10,447
Distributed generation—base	2025	2	3	\$1,915	1.00	\$1,915	\$9.69	\$21.79	8,912
Distributed generation—peak	2024	1	2	\$2,300	1.00	\$2,300	\$9.69	\$21.79	9,894
Battery storage	2023	50	1	\$1,270	1.00	\$1,270	\$0.00	\$45.76	NA
Biomass	2026	50	4	\$4,996	1.00	\$4,998	\$5.44	\$141.50	13,500
Geothermal ^{i,j}	2026	50	4	\$3,403	1.00	\$3,403	\$1.31	\$153.98	8,881
Conventional hydropower ^l	2026	100	4	\$3,421	1.00	\$3,421	\$1.57	\$47.06	NA
Wind ^k	2025	200	3	\$2,098	1.00	\$2,098	\$0.00	\$29.64	NA
Wind offshore ⁹	2026	400	4	\$5,338	1.25	\$6,672	\$0.00	\$123.81	NA
Solar thermal ^l	2025	115	3	\$8,732	1.00	\$8,732	\$0.00	\$96.10	NA
Solar photovoltaic (PV) with tracking ^{5,i,k}	2024	150	2	\$1,448	1.00	\$1,448	\$0.00	\$17.16	NA
Solar PV with storage ^{l,k}	2024	150	2	\$1,808	1.00	\$1,808	\$0.00	\$32.42	NA

There are some footnotes to each table; I have included below those related to Table 2-3.

Data source: Sargent & Lundy, Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, December 2019; Hydroelectric: Oak Ridge National Lab, An Assessment of Energy Potential at Non-Powered Dams in the United States, 2012, and Idaho National Engineering and Environmental Laboratory, Estimation of Economic Parameters of U.S. Hydropower Resources, 2003; Geothermal: National Renewable Energy Laboratory, Updated U.S. Geothermal Supply Curve, 2010.

Note: MW=megawatt, kW=kilowatt, MWh=megawatthour, kWyr=kilowattyear, kWh=kilowatthour; Btu=British thermal unit

^a The first year that a new unit could become operational.

^b Base cost includes project contingency costs.

^c We apply the technological optimism factor to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

^d Overnight capital cost includes contingency factors and excludes regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. The capital costs represent current costs for plants that would come online in 2023.

^e Total overnight cost for wind and solar PV technologies in the table are the average input value across all 25 electricity market regions, as weighted by the respective capacity of that type installed during 2021 in each region to account for the substantial regional variation in wind and solar costs (Table 4). The input value used for onshore wind in AEO2023 is \$1,566 per kilowatt (kW), and for solar PV with tracking, it is \$1,443/kW, which represents the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs throughout the country.

^f O&M=operations and maintenance

^g The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860, *Annual Electric Generator Report*. No heat rate is reported for battery storage because it is not a primary conversion technology; conversion losses are accounted for when the electricity is first generated, and electricity-to-storage losses are accounted for through the additional demand for electricity required to meet load. For hydropower, wind, solar, and geothermal technologies, no heat rate is reported because the power is generated without fuel combustion, and no set British thermal unit conversion factors exist. The module calculates the [average heat rate for fossil-fuel generation](#) in each year to report primary energy consumption displaced for these resources.

^h Combustion turbine aeroderivative units can be built by the module before 2024, if necessary, to meet a region's reserve margin.

ⁱ Capital costs are shown before investment tax credits are applied.

^j Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries show the cost of the least expensive plant that could be built in the Northwest region for hydro and the Great Basin region for geothermal, where most of the proposed sites are located.

^k Costs and capacities are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

Overnight costs are what the technology would cost in \$/kW if it were built in one day (and therefore excludes the allowance for funds used during construction, AFUDC).

Overnight costs are described as follows [4, 7]:

- Bare erected cost (BEC): cost of equipment, on-site facilities/infrastructure supporting the plant, direct/indirect labor required for its construction and/or installation.
- Engineering, procurement and construction cost (EPCC): BEC+cost of services provided by EPC contractor (design, contractor permitting, project management cost).
- Total plant cost (TPC): EPCC+project contingencies.
- Total overnight cost (TOC): TPC+owner's cost (start-up costs+inventory capital+cost of securing financing, excluding AFUDC²).

² Allowance for Funds Used During Construction (AFUDC) is the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used. In short, it is the interest during construction (IDC).

The capitalization period for AFUDC begins when two conditions are present: (1) capital expenditures for the project have been incurred; and (2) activities that are necessary to get the construction project ready for its intended use are in progress. AFUDC capitalization continues as long as these two conditions are present.

Capitalization of AFUDC stops when the facilities have been tested and are placed in, or ready for, service. This would include those portions of construction projects completed and put into service although the project is not fully completed. See "ACCOUNTING RELEASE NUMBER 5 (AR-5) (Revised)" of <https://www.ferc.gov/sites/default/files/2020-05/AI11-1-000.pdf>.

Overnight costs characterize capital expenditures (CAPEX). Ref [8] provides a good characterization of CAPEX.

Overnight costs are illustrated in Figure 2-3 [7]. Note: numerical values in the figure, though representative at the time, are no longer representative of the cost of these technologies.

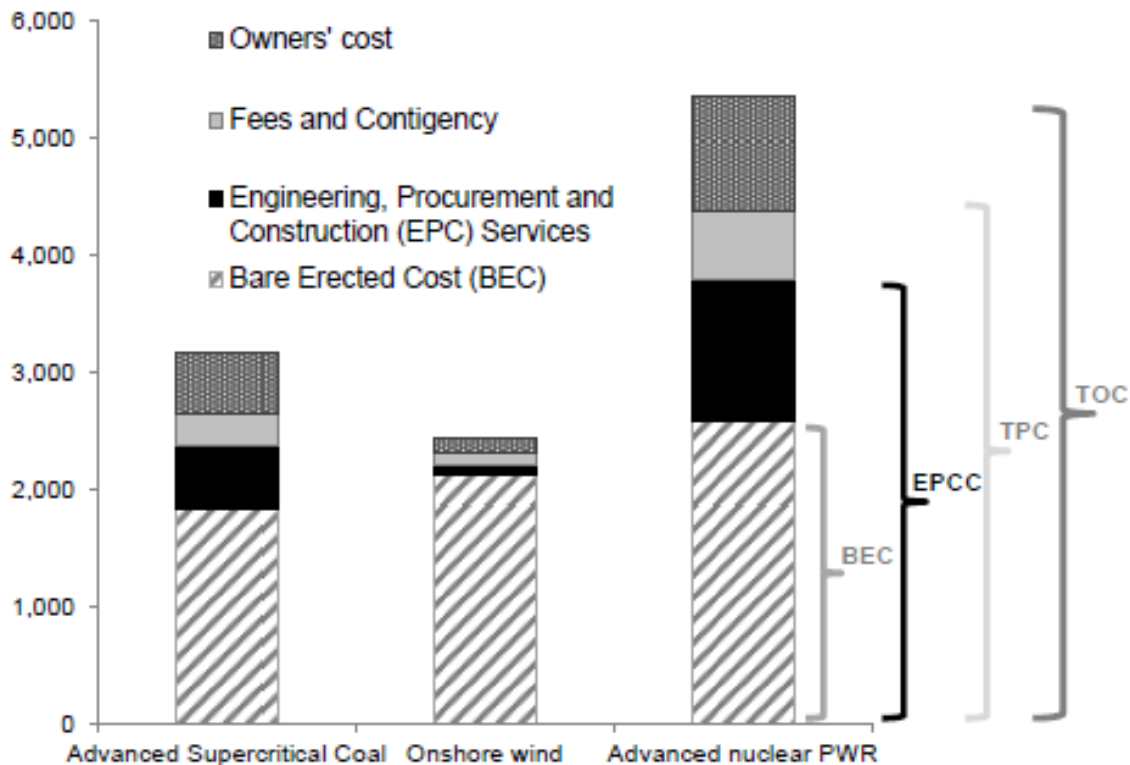


Figure 2-3: Overnight costs [7]

3 Cost of capital

3.1 Assets

A basic concept in rate-regulated electric utility economics is that of the electric utility balance sheet. The left-hand-side of the balance sheet lists all of the *asset values*:

- Plant (facilities) at original costs,
- Less depreciation,
- Plus construction work in progress,
- Plus cash, accounts receivable, materials/supplies on hand.

3.2 Liabilities and owner's equity

The right-hand-side of the balance sheet lists the *liabilities* (what is owed) and *owner's equity* (difference between what is owned and what is owed). Liabilities include:

- Long-term debt: Money the utility has borrowed through bonds at a stipulated interest rate and a stipulated maturity.
- Current liabilities: This includes short-term debt, accounts payable, and customer deposits.

Owner's equity include stock³, which permits public ownership of the utility. Equity means ownership through stocks. There are two forms:

- Common stock: This is where the bulk of ownership resides. Each common stockholder can vote in electing the board of directors. But common stock has no fixed yield but rather, dividends are paid to stockholders at the year's end in proportion to the company's annual profit and number of shares owned by the stockholder. *This dividend is according to the regulators allowed rate of return.*
- Preferred stock: This has a fixed yield but no vote.

The *accounting equation* of the balance sheet is then

$$\text{Owner's Equity} = \text{Assets} - \text{Liabilities} \quad (1)$$

Equity is the monetary value of assets in excess of liabilities against it. It is the amount of money that would be available if the assets were liquidated and all debts paid.

3.3 Discount rate

The discount rate is typically a weighted average over the different interest rates paid for the cost of capital. As a result, sometimes it is called the weighted average cost of capital (WACC). For example, a utility could finance its new assets as follows:

³ Stocks represent ownership in a corporation. Bonds are long-term debt where the corporation promises to pay the principal amount on a future date.



- 50% in bonds at an interest of 7%
- 10% in preferred stock at a dividend yield of 11%
- 40% in common stock expected to achieve a (regulated) 15% return

So the discount rate is computed as

$$i=0.5*0.07+0.1*0.11+0.4*0.15=0.0746$$

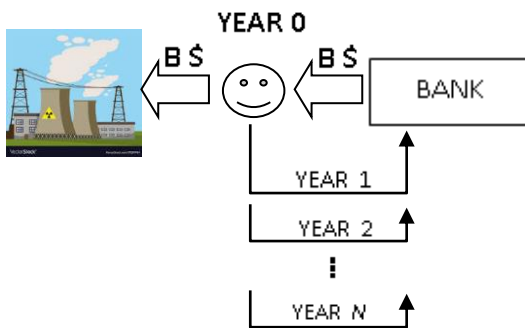
Therefore, the discount rate would be 7.46%.

The discount rate is the

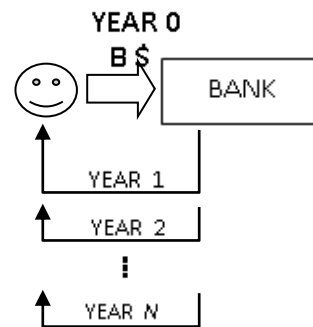
annual payment as a percentage of the amount owed.

The discount rate may also be thought of as reflecting the value given to possession of money now rather than later, since having it now allows it to be invested (in, for example, financial markets, e.g., stocks & bonds) to earn a return. In this sense, the discount rate is

annual income as a percentage of the amount invested.



the annual payment as a percentage of the amount owed



the annual income as a percentage of the amount invested.

These thoughts make use of the time value of money, which we mention next.

But, before we do, we make some clarifications:

- The discount rate does *not* reflect depreciation; depreciation reflects the reduced value of the facilities.
- The discount rate should *not* be confused with
 - the fixed charge rate which reflects the cost of borrowed money, depreciation, fixed O&M, and when based on “nominal” discount rate, does not reflect inflation (see footnote 1 on the relation between FCR and discount rate).
 - the discount factor, given as $d=1/(1+i)$ [or, sometimes the discounting factor, given as $d^N=1/(1+i)^N$].

3.4 Moving single amounts in time

We briefly mention this now to motivate the time value of money. We will return to this topic in Section 4.

Consider we have an amount of money now equal to P dollars. If there is a bank where we can draw i % interest per year, then in one year, we will have

$$F = P(1+i)^1 \quad (2)$$

and if we leave it in the bank for N years, then we will have

$$F = P(1+i)^N \quad (3)$$

Then, it works the other way as well, that is, if we know we want F in the bank in year N , then we need to deposit P now:

$$P = \frac{F}{(1+i)^N} \quad (4)$$

This relation is illustrated in Figure 3-1 (also in Figure 4-1).

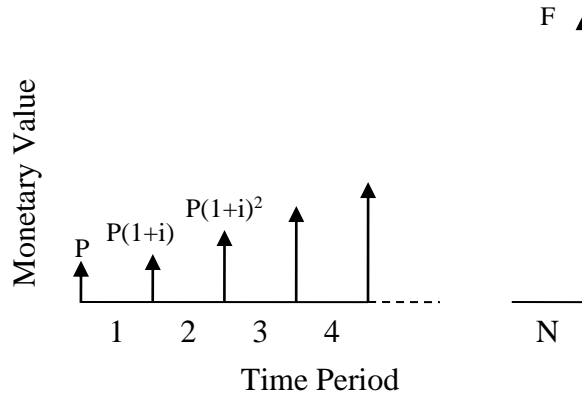


Figure 3-1: Relation between present and future dollars

Observe that F may be a cost or a revenue. In either case, the equivalent amount of money in the present is smaller:

- I prefer to incur a \$100 cost later than a \$100 cost now (if I spend the \$100 later, then I can keep it now and draw interest on it).
- I prefer to obtain a \$100 revenue now than a \$100 revenue later (if I obtain it now, then I can draw interest on it, so the value to me of obtaining it in the future is less).

3.5 Effect of inflation

Discount rates may be given independent of the effects of inflation. This is the interest rate that is typically quoted on savings accounts, bonds, and loans; it quantifies the amount you are paid (when you save or buy a bond) or must pay (when you obtain a loan). For example, if your savings account pays you 4% per year, and you deposit \$100 at the beginning of the year, you will have \$104 at the end of the year.

→ The 4% is called the *nominal* discount rate. We will represent it as i_n .

Now assume inflation is $e=3\%$ per year. Then, at a nominal rate of $i_n=4\%$, the \$104 at the end of year has a buying power that is diminished by $e=3\%$ relative to the beginning of the year. And so

$$\text{Effective Value} = 100 \left[\frac{1.04}{1.03} \right] = 100.97 \quad (5)$$

You can see that this is correct as follows. Assume you hold \$100.97 in your hands (and so we are ignoring interest from the bank) for a year during which inflation is $e=3\%$, and you ask, at year-end: “What was this \$100.97 worth at the beginning of the year?” The answer would be:

$$100.97 \times 1.03 = 104 \quad (6)$$

that is, it was worth over \$3 more at the beginning of the year than it is now as you stand and look at it in your hand. The reason is that over the last year, everything got more expensive due to inflation, and the buying power of \$100.97 a year ago is equivalent to \$104 of buying power now.

Let’s go back now and consider the equation we wrote to express the effective value of the original \$100 at the beginning of the year.

$$\text{Effective Value} = 100 \left[\frac{1.04}{1.03} \right] = 100.97 \quad (7)$$

It is not $100[1+0.04-0.03]=101$, although it is very close to that. The reason is that there is also the effect of inflation on the interest. See fisher equation below, eq. 13.

The numerator of the fraction is $(1+i_n)$. The denominator is $(1+e)$. Thus we have

$$\text{Effective Value} = 100 \left[\frac{1+i_n}{1+e} \right] = 100.97 \quad (8)$$

Now here is another question: What is the interest rate that, when applied to the original \$100, will give us \$100.97? We might call this the effective interest rate, but the normal terminology is to call this the real interest (or real discount) rate; we denote it by i_r . And so

$$100(1+i_r)=\text{Effective Value}=100\left[\frac{1+i_n}{1+e}\right]=100.97 \quad (9)$$

That is,

$$100(1+i_r)=100\left[\frac{1+i_n}{1+e}\right] \quad (10)$$

from which we immediately see that

$$(1+i_r)=\left[\frac{1+i_n}{1+e}\right] \quad (11)$$

Solving for i_n results in:

$$1+i_n=(1+i_r)(1+e)=1+e+i_r+i_re \quad (12)$$

Equation (12) is called the “Fisher equation.”

Eliminating the “1” we get

$$i_n=e+i_r+i_re \quad (13)$$

Solving for i_r results in

$$i_r=\frac{i_n-e}{1+e} \quad (14)$$

These are “exact” relations and should be used in calculations. But because e and i_r are small numbers, the product i_re is very small, and we obtain

$$i_n=e+i_r \quad (16)$$

or

$$i_r=i_n-e \quad (17)$$

These are useful for recalling relations between i_n , i_r , e .

In summary, the exact and approximate relations are:

	To get nominal value	To get real value
Exact	$i_n = e + i_r + i_r e$	$i_r = \frac{i_n - e}{1 + e}$
Approximate	$i_n = e + i_r$	$i_r = i_n - e$

Caution #1: It is tempting to think that, because inflation adds to i_r to obtain i_n , that i_n captures the effects of inflation. This is not the case. Inflation is an effect that is counter to the interest (or discount) rate – we receive our interest and the consequential increase in money, but we suffer inflation and the consequential decrease in value. With this in mind, the relation $i_r = i_n - e$ shows that it is the real interest rate that *includes the effect of inflation*. Good references for this material include [9, 10].

Caution #2: Semantics can be treacherous. In [10, p. 24], it defines the “real discount rate” as “an interest rate that has been adjusted *to remove the effect of* expected or actual *inflation*.” Note italicized phrases under the two “Cautions,” i.e., compare *includes the effect of inflation* (Caution #1) with *to remove the effect of inflation* (here, Caution #2). The explanation follows:

- Caution #1 *includes the effect of inflation within the interest rate*;
- Caution #2 *removes the effect of inflation* from the monetary values produced by the interest rate (they become constant, or “real” dollar values).

Here is a useful way to think about this issue:

- Using i_n does not carry with it the influence of inflation, and so the numbers used with i_n must; thus those numbers must be current dollars.
- Using i_r carries with it the influence of inflation, and so the numbers used with i_r cannot; thus those numbers must be constant dollars.

Ref [9] is US census bureau – they estimate consumer incomes. And [10] is OMB - the OMB oversees the implementation of the President’s vision across the Executive Branch, including budget development & execution for the US government.

3.5.1 Example:

Compute the real discount rate if the nominal discount rate is 11.5% and the inflation is 3%.

Exact and approximate:

$$i_r = \frac{i_n - e}{1 + e} = \frac{.115 - .03}{1.03} = 0.0825$$

$$i_r \approx i_n - e = .115 - .03 = 0.085$$

This brings us to distinguish between two different ways of referring to money over different periods of time:

- Current or nominal dollars are actual cash flows that would occur during each particular year, and so, \$1 in 2020 has less buying power than \$1 in any previous year. Nominal dollars are not, therefore, referenced to a particular year. *Use nominal discount rate with current dollars.*
- Constant or real dollars get adjusted for inflation by the real discount rate and are therefore “constant-value” dollars, i.e., their expression in one year has equivalent buying power as their expression in another year. Constant dollars are always referenced to a particular year, e.g., “2015 dollars,” i.e., when doing so, we are saying that “\$1 in 2020 has the same buying power as \$1 in 2015.” *Use real discount rate with constant dollars.* For example, Table 2-3 provides all of its cost in “2022 dollars.” The values of these tables may be used for any year, as long as a real discount is used with it, and the passage of time is referenced to 2022.

➔ Unless otherwise stated, assume we use constant dollars with the real discount rate. This is consistent with the fact that on cost data (e.g., Table 2-3), we see the reference year. A brief but good reference on these issues was written by, interestingly, a legal consultant concerned with identifying the present value of future damages for clients [11].

3.5.2 How to estimate discount rate

The White House Office of Management and Budget (OMB) [10], called Circular A-94, Appendix C [12] indicates that the nominal 20-year and 30-year discount rate for calendar year 2024 on treasury notes and bonds is 4.7%. This would establish a lower bound on the nominal discount rate as returns on infrastructure investments are generally higher than those on treasury notes and bonds.

A 2023 OMB paper [13] on regulatory analysis stated

“The real (inflation-adjusted) rate of return on long-term U.S. government debt provides a fair approximation of the social rate of time preference,”

and it identifies 2.0% as the desired real discount rate. Since this is a real discount rate, then the nominal discount rate would be $2.0+e$, where e is the inflation rate. The webpage of the US Bureau of Labor Statistics [14] provides plots of “12-month percent change in Consumer Price Index,” which is the annual inflation rate, as shown in Figure 3-2. From this data, we compute the average annual inflation rate 1958-2023 to be 3.7%, and the average annual inflation rate 2000-2023 to be 2.3%.

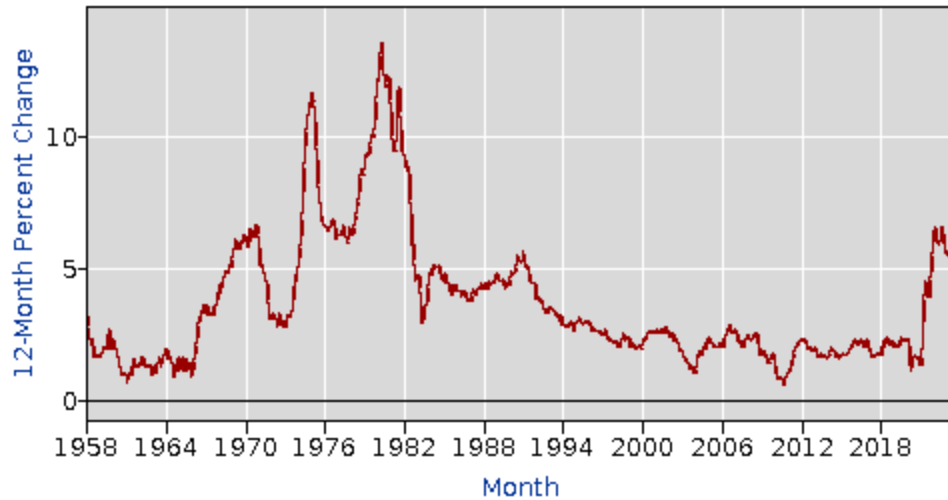


Figure 3-2: Annual inflation rate 1958-2023

Using the 2.3% to 2.7% range, we select 3% to be a reasonable expected average inflation rate for the next 25 years (a typical expansion planning decision horizon). Recalling the nominal discount rate is $i_r + e$, and with the real discount rate to be $i_r = 2.0$, we compute the nominal to be $2.0 + 3.0 = 5.0\%$ per year. Given our previous lower bound on treasury notes and bonds, this seems to be a reasonable value of nominal discount rate for expansion planning studies.

4 Time value of money – additional relations

Amounts of money at different points in time cannot be directly compared due to the time value of money.

The value of money received today is higher than the same amount of money received in the future because money received today can be invested to yield the original investment plus interest. Therefore, in order to compare

alternatives having cash flows at different times, amounts of money must be expressed in equivalent amounts at common points in time.

The process of calculating equivalent values is referred to as *discounting* if amounts are brought back in time; it is referred to as *compounding* if amounts are moved forward into the future. These techniques may be applied to both single amounts and annuities. An *annuity* is a series of equal payments made at regular intervals.

The following relations are used in computing equivalent values of money. Some nomenclature:

- i : the interest rate per period, or the discount rate.
- N : the number of interest or discounting periods.
- P : a “present” amount of money.
- F : a “future” amount of money at the end of N periods.
- A : an end-of-period payment (or receipt) in a uniform series of payments (or receipts) over N periods at i interest or discount rate.

It is common convention to assume that

- all capital investments or expenses occur at the beginning of the year, and
- all fixed and variable costs associated with capital investments occur at the end of the year.
- annuity payments are assumed to occur at the end of each time period (as previously mentioned).

Single Amounts moved in time:

The present worth factor (PWF) is used to determine the equivalent present value of a future expenditure:

$$P = F \times \text{PWF} = F \times \frac{1}{(1+i)^N} \quad (19)$$

The compound amount factor (CAF) is used to determine the equivalent future value of a present expenditure:

$$F = P \times \text{CAF} = P \times (1+i)^N \quad (20)$$

Figure 4-1 illustrates these two calculations.

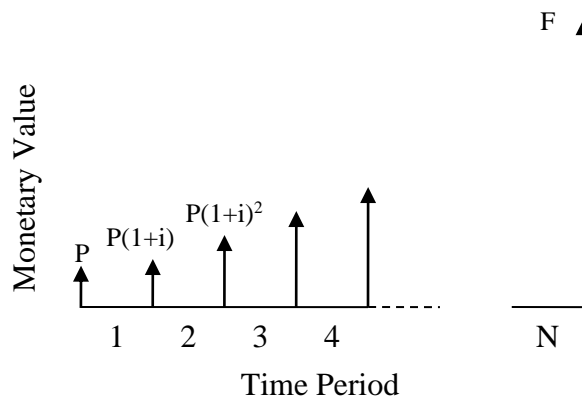


Figure 4-1: Relation between present and future values

Annuities to single amounts:

The series present worth factor (SPWF) is used to determine the equivalent present value of a series of equal payments (an annuity):

$$P = A \times \text{SPWF} = A \times \frac{(1+i)^N - 1}{i(1+i)^N} \quad (21)$$

The series compound amount factor (SCAF) is used to determine the equivalent future value of a series of equal payments (an annuity):

$$F = A \times \text{SCAF} = A \times \frac{(1+i)^N - 1}{i} \quad (22)$$

Figure 4-2 illustrates these two calculations. Note that payment A is made at the end of a period, so there is no payment made at the beginning of period 1, but there is a payment made at the end of period N . It is easy to use (21) and (22) to show that P and F are related to each other via (19) and (20) (solve for A in (21) and (22); then equate expressions).

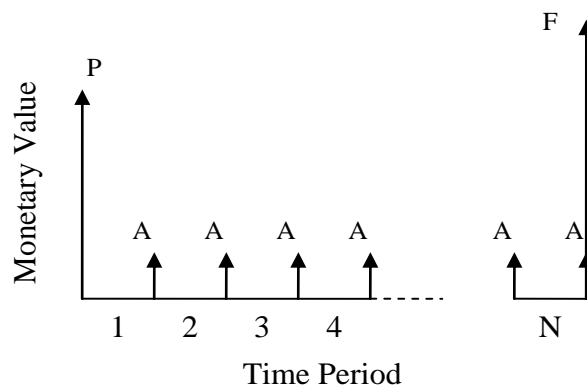


Figure 4-2: Cash flow diagram for a uniform series of payments

Single amounts to annuities:

The sinking fund factor (SFF) is used to determine the annuity that is equivalent to a future expenditure:

$$A = F \times \text{SFF} = F \times \frac{i}{(1+i)^N - 1} \quad (23)$$

This is used, for example, when we want to save an amount, F , at year N by saving $\$A$ per year at interest i .

The capital recovery factor (CRF) is used to determine the annuity that is equivalent to a present expenditure:

$$A = P \times \text{CRF} = P \times \frac{i(1+i)^N}{(1+i)^N - 1} \quad (24)$$

This is used, for example, when we owe a present debt P that we want to zero at year N by paying $\$A$ per year at interest i .

Example: An electric utility finances $\$9,426,914$ to build a 6-mile-long transmission line at an annual rate of 10%. What is the annual payment necessary for repayment at 30 years?

Answer: This is a capital recovery problem, with $N=30$, $i=0.1$, and $P=\$9,426,914$. From (24), we have

$$\begin{aligned} A &= P \times \frac{i(1+i)^N}{(1+i)^N - 1} \\ &= 9426914 \times \frac{0.1(1+0.1)^{30}}{(1+0.1)^{30} - 1} = 9426914 \times 0.1061 = 1,000,000 \end{aligned}$$

Some interesting questions:

1. How much of year 1 is interest; how much reduces the principal?

➔ Interest = $0.1 * 9,426,914 = \$942,691.40$

So $1000000 - 942,691.4 = \$57,309$ reduces the principal.

2. How much of year 2 is interest; how much reduces the principal?

➔ The new principal is $9,426,914 - 57,309 = 9,369,605$

Interest = $0.1 * 9,369,605 = \$936,960.5$

So $1000000 - 936,960.5 = \$63,040$ reduces the principal.

Proceeding in this fashion, we may obtain the amount of each year's million-dollar payment that is interest and the amount that reduces the principal. Figure 4-3 illustrates [3].

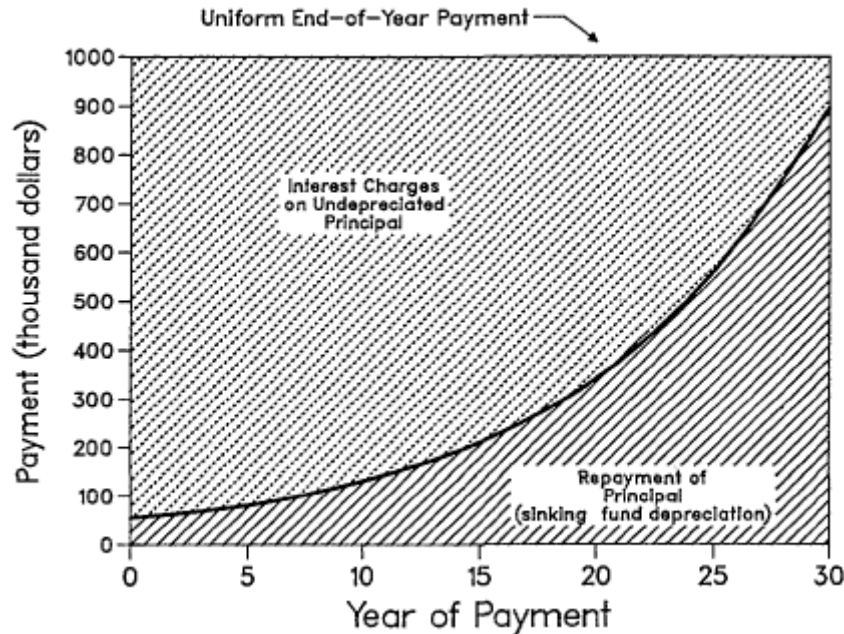


Figure 4-3: Illustration of each year's interest and principal

5 Economic evaluation methods

We need to recognize the difference between planning within

- a competitive business enterprise and
- an organization where rate of return on the rate-base is fixed by regulators.
- an organization that is rate-regulated and competitive.

In all discussion in this section, we assume we are using the real discount rate, and so all dollars are “constant value,” i.e., the effect of inflation is accounted for in the discount rate, and we can use “today’s” dollar values for all years.

5.1 Competitive business enterprise

In a competitive business enterprise, the most widely used economic evaluation method is called a “discounted cash-flow rate of return method.” In this method, the expectation is that future cash flows will provide a return on the original investment. Therefore, we consider alternatives with rates of

return that exceed the cost of money, and we choose the largest of these. It proceeds as follows:

1. Future cash flows F_t are identified through the planning horizon of the evaluation as $F_t = R_t - E_t$ where R_t and E_t are estimated revenues (income) and expenditures, respectively, for year t . These cash flows do not include the initial investment P_0 (parameters P_0 , R_t , and E_t are positive values, but F_t may be positive or negative).
2. The discount rate i^* is identified which results in the sum of future cash flows F_t equaling the initial investment P_0 . This rate is called the “discounted cash-flow rate of return.”

$$P_0 = \sum_{t=1}^N F_t \times \frac{1}{(1+i^*)^t} \quad (25)$$

In the above, t is the year that cash flow F_t occurs, N is the final year of the planning horizon, and i^* is the discounted cash-flow rate of return. The above equation can be iteratively solved for i^* .

3. All projects that have a discounted cash-flow rate of return i^* that exceeds the cost of money i (what it costs to borrow the funds) are considered worthwhile projects. The project with the highest discounted cash-flow rate of return i^* is considered the best project.

5.2 Rate regulated enterprise

But what about regulated electric utilities? Note the below article about wind development in Iowa, from 2015.

Utilities board issues proposed rate of return for MidAmerican wind project

Monday, August 24, 2015 10:54 AM

MidAmerican Energy took a step closer to getting its next major wind project in Iowa approved on Friday. The Iowa Utilities Board issued an order approving settlement with modification and requiring reports regarding MidAmerican Energy's proposed "Wind X" Iowa electric generation project of up to 552 megawatts.

In modifying the settlement agreement, the board's order sets the cost cap for Wind X at \$1.61 million per megawatt, including allowance for funds used during construction, which is down from \$1.638 million per megawatt for the completed project as a whole. The board said in a release, "This lower cap reduces the risk to customers and provides an incentive to MidAmerican to keep costs low while still

The main point here (yellow) is that allowable return is specified. This means that the variable they must control is the cost.

A second point here (green) is MidAmerican was allowed "advance ratemaking principles" which mean the return is specified in advance (subject to conditions). This reduces risk for MidAmerican and has been a major driver for Iowa wind growth.

providing a contingency for unanticipated changes that could increase costs above that shown by MidAmerican's economic analysis."

The settlement agreement for the more than \$888 million project provides that MidAmerican's allowed return on the common equity portion of Wind X that will be included in Iowa electric rate base will be 11.35 percent, down from 11.5 percent proposed by MidAmerican. The board stated, "The agreed-upon ROE is lower than that awarded in any prior MidAmerican **advance ratemaking** proceeding including Wind IX, the most recent docket."

Before the board could determine **applicable ratemaking principles** for Wind X, two statutory conditions had to be met under Iowa code. First, MidAmerican has to have in effect a board-approved energy-efficiency plan. Second, MidAmerican must demonstrate that it has considered other sources for long-term energy supply and that the facility is reasonable when compared with other feasible alternative sources of supply.

MidAmerican will have 30 days from Friday's decision to notify the board whether it accepts the **ratemaking principles** awarded. If accepted, the **ratemaking principles** would be effective for the regulated life of the facilities.

And, more recently [15] (April 2023):

The Iowa Utilities Board (IUB) today issued its final decision and order approving MidAmerican Energy Company's (MidAmerican) application for advance ratemaking principles regarding its proposed Wind PRIME project. MidAmerican's estimated \$3.9 billion project consists of up to **2,042 megawatts (MW) of new wind generation and up to 50 MW of solar generation in Iowa.**

MidAmerican filed its application for determination of ratemaking principles on January 19, 2022, and a non-unanimous settlement on December 2, 2022, seeking 12 ratemaking principles under Iowa Code § 476.53. **Under Iowa law and the IUB rules at 199 Iowa Administrative Code chapter 41, the IUB is authorized to approve advance ratemaking principles for alternate energy production facilities that will apply when such facilities are included in rates paid by customers.** Today's order approved 11 ratemaking principles. A comprehensive description of principles is attached to the order.

Under Iowa Code § 476.53, the IUB must make four overall findings to support the granting of advance ratemaking principles: (1) the application must address qualifying facilities under the statute, (2) the facilities must be needed in the context of sufficient quantity of generation for reliable long-term electric supply, (3) the utility must have an IUB-approved energy efficiency plan in place, and

(4) the IUB must determine that the proposed facilities are reasonable when compared to other feasible alternative sources of supply to meet the identified need.

So, in contrast to the discounted cash-flow rate of return method, as we have seen, a regulated organization has its rate of return that can be provided to common stockholders fixed by the regulatory agency. As a result, the “discounted cash-flow rate of return method,” which compares different alternatives based on a computed rate of return, should not be used. Rather, methods which compare different alternatives based on a computed equivalent cost, for a fixed rate of return, make more sense.

A common approach for economic evaluation of alternatives used by utilities, under the traditional regulated business model, is called the *revenue requirements method*.

The revenue requirements method answers the following question: How much revenue is needed in order to achieve a specified rate of return? Since revenue is the answer we are trying to obtain, we do not need to estimate R_t .

Revenue requirements consist of two items: the annual fixed charges on a new investment (e.g., return, depreciation, taxes, insurance) and the annual expenses for fuel, operation, and maintenance. Calculations are made using the formula accounting for time value of money, to enable proper comparison between the alternatives.

One approach is to discount all costs associated with a project, present & future, to a specific point in time, usually the beginning of the study period, according to:

$$P = \sum_{t=1}^N E_t \times \frac{1}{(1+i)^t} \quad (26)$$

The use of (26) differs from (25) in that

- (26) uses only cash flows corresponding to future costs E_t (since we are trying to determine the revenue requirements), whereas (25) uses both future costs E_t and future revenues R_t .
- (26) is used knowing i to compute the present worth P of the costs, whereas (25) is used knowing the investment P_0 to compute i^* .

When (26) is applied to all alternatives, then the present value of the costs for one alternative can be directly compared with the present value of the costs for the other alternatives to identify the alternative having the least present value.

One disadvantage of this approach is that the present value of all costs for an alternative can be quite large. To help make the total cost for an alternative easier to comprehend and to give the analyst a better feel for the annual differences between alternatives, the costs can be expressed on an equivalent annual cost basis.

Equivalent annual costs, also called levelized annual costs, represent the annuity which is exactly equivalent to all the costs incurred in an alternative. One method of making this

calculation is to first determine the present value of all costs for an alternative (at the beginning of the study period), and then multiply this present value by the capital recovery factor for the length of the study period to “levelize” the costs over the study period, that is:

$$P = \sum_{t=1}^N E_t \times \frac{1}{(1+i)^t} \quad (26)$$

$$A = P \times \text{CRF} = P \times \frac{i(1+i)^N}{(1+i)^N - 1} \quad (27)$$

These costs are sometimes referred to as the levelized annual revenue requirements (LARR). Here, it is important to recognize that (similar to FCR), whereas the present worth P evaluates the same independent of whether current dollars and nominal discount rate are used, or constant dollars and real discount rate are used, the LARR depends on whether the discount rate is nominal (giving the nominal LARR) or real (giving the real LARR). Footnote 1 also addressed this.

It is important to understand the distinction between LARR and actual revenue requirements. Since actual revenue requirements are seldom constant each year over the life of a project, it is difficult to compare actual revenue requirements between alternative projects. Thus, LARR represents the annuity that is **equivalent** to the actual revenues the company needs to receive in order to cover their costs.

The rate-regulated business enterprise uses the levelized annual revenue requirements (LARR) method to identify

projects that have the least LARR for a given rate of return. This LARR is used to identify the energy prices imposed (with regulatory agreement) on the energy consumers. This is the way planning engineers in a vertically-integrated, fully regulated utility must operate. We can think of this situation as illustrated in Figure 5-1, where arrows out of, or into a box indicate a cost (expense), or a revenue, respectively, for the organization represented by the box.

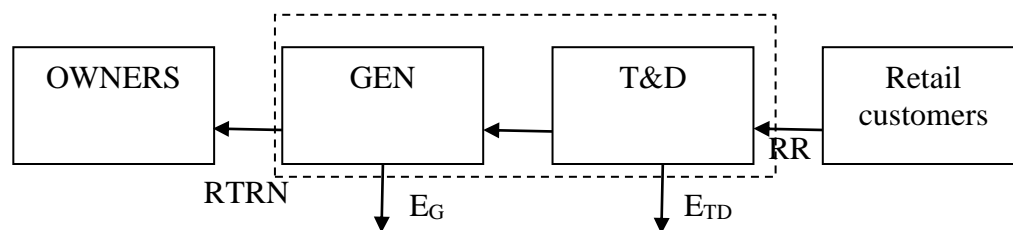


Figure 5-5-1: Financial flows for rate-regulated vertically-integrated entities

Here, we observe the conceptual financial flow balance equation for rate-regulated enterprises (in the dotted box) is:

$$RR = (E_G + E_{TD}) + RTRN \quad (28)$$

where E_G and E_{TD} are the operating expenses of the generation, transmission, and distribution systems, $RTRN$ is the return allowed to the owners (investors), and RR is the revenue requirement from selling energy to the retail customers. The utility would engage with the regulator to determine allowable $RTRN$; generally, the $RTRN$ is specified as a percentage of the so-called rate-base. The rate-base is the value of all infrastructure owned by the utility, accounting for depreciation. Sometimes there are intense discussions between utility and regulator on what can go into the rate base. RR is computed which sets the rates for the customers.

5.3 Generation owners in electricity markets

The competitive business enterprise uses the discounted cash flow rate-of-return method to identify projects having the highest rate of return. Owners of generation operating in competitive markets need to look more like a competitive business enterprise, rather than a rate-regulated enterprise. This is illustrated in Figure 5-5-2.

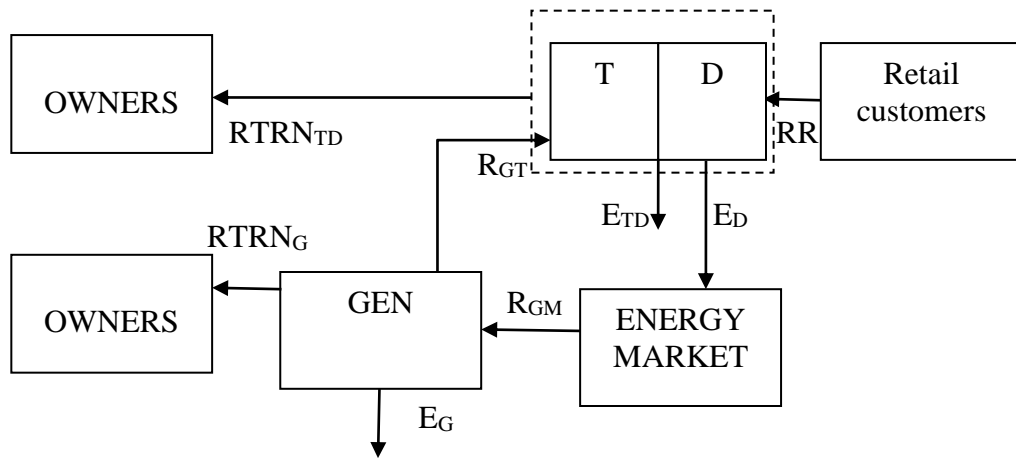


Figure 5-5-2: Financial flows when gens operate in markets

We observe the conceptual financial flow balance equation for the rate-regulated T&D enterprise (in the dotted box) is:

$$RR = (E_{TD} + E_D - R_{GT}) + R_{TRN_{TD}} + R_{TRN_G} \quad (29a)$$

The financial flow balance equation for the gen entity is

$$R_{GM} = E_G + R_{TRN_G} + R_{GT} \quad (29b)$$

The total system financial flow balance equation is similar to that of the rate-regulated vertically integrated entity of (28)

$$RR = (E_G + E_{TD}) + R_{TRN_{TD}} + R_{TRN_G} \quad (30)$$

where the only difference is that the return to the owners is split between T&D owners and generation owners.

Example: Consider three power plants having the below data. One is a pulverized coal power plant, one is a combined cycle plant, and one is a nuclear plant. Here we assume fuel costs dominate the other O&M. All three plants are assumed to have 40 year lives. Assume all dollar values are 2010 dollars. The fuel price forecasts reflect the effect of inflation on each individual fuel type. The levelized fixed charge rate is based on a nominal discount rate and so its use produces a levelized “current dollar” value which can be appropriately added to the current dollar values obtained from the fuel price forecasts.

Data	PC plant	NGCC plant	Nuclear plant
Overnight cost	\$1600/kW	\$850/kW	\$2300/kW
Levelized fixed charge rate	20%	20%	20%
Plant rating	1000 MW	1000 MW	1000 MW
Full-load heat rate	9.6 MBTU/MWh	7.2 MBTU/MWh	9.3 MBTU/MWh
2010 fuel price	\$1.75/MBTU (coal)	\$8.00/MBTU (gas)	\$0.85/MBTU (uranium)
Forecasted fuel price increase	1%/year	2%/year	1%/year
Capacity factor	1.0	1.0	1.0
Nominal discount rate	8%	8%	8%

Compute and plot, in current (nominal) dollars:

1. The fuel price forecast for the three fuels, assuming the initial 2010 fuel price and the given forecasted rates of increase (this will be in current dollars, i.e., the dollar values will reflect the effect of inflation).

2. The operational cost for the three plants, assuming they operate at the given capacity factor 8760 hrs/year (again, this will be in current dollars, i.e., the dollar values will reflect the effect of inflation).
3. The levelized annual fixed charges for the three plants, assuming the given levelized fixed charge rate (since the 20% FCR was computed based on a nominal discount rate, use of this nominal FCR produces a levelized data stream that includes the effects of inflation; thus, these values may be directly added to the operational cost of step 2 to obtain the total annual costs in step 4).
4. The total annual costs for the three plants

Also compute

5. the present value of the investment plus operating cost;
6. the levelized value of the investment plus operating cost.

Solution:

1. Fuel price forecast:

This is obtained according to $p_{t+1}=(1+r)p_t$, where r is the forecasted rate of change in fuel price. Observe in Fig. 5-3 that the rate of increase in natural gas prices is significantly greater than the rate of increase in coal and uranium prices, due to the different assumptions made for fuel price increases. (This assumption is not reasonable today with shale gas prices being so low).

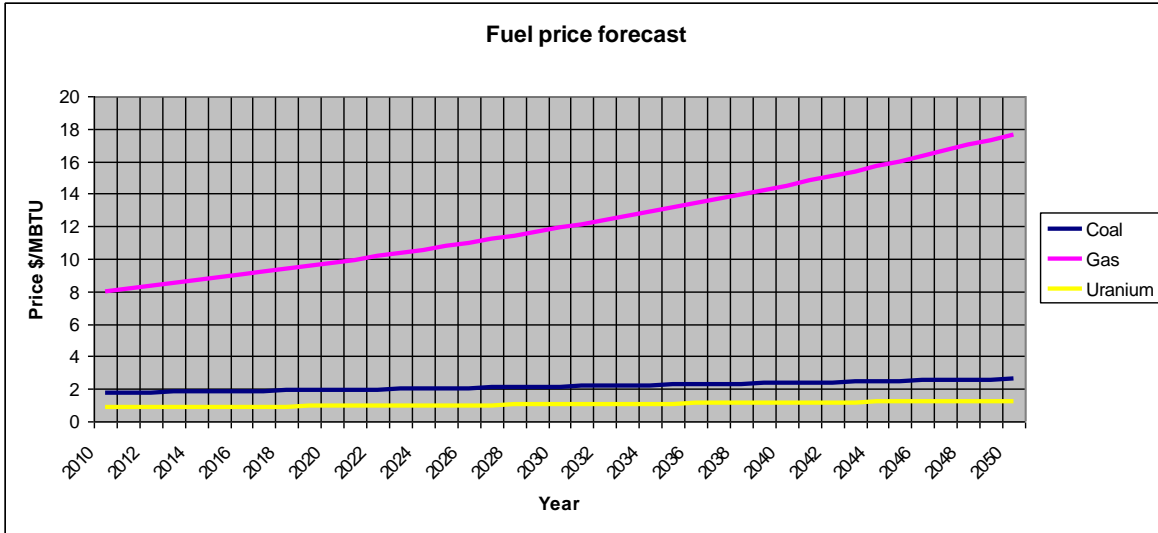


Figure 5-3: Fuel price increase with year, current dollars

2. Operational cost for the three plants is obtained from:

$$\begin{aligned} \text{OpCost}(t) &= \text{Cap} * \text{Capfactor} * 8760 * \text{Heatrate} * \text{Fuelprice}(t) \\ &= 1000 * 1 * 8760 * \text{Heatrate} * \text{Fuelprice}(t) \end{aligned}$$

This is illustrated in Fig. 5-4.

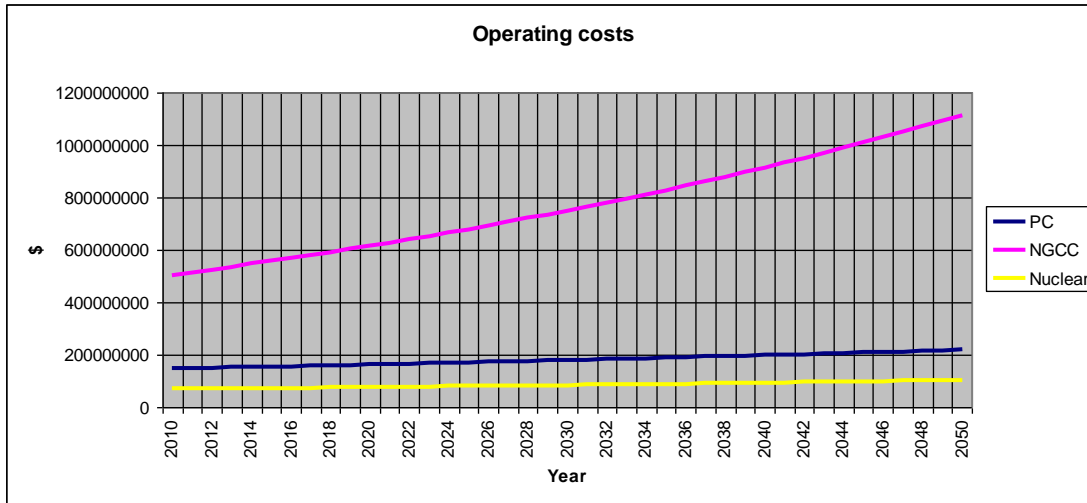


Figure 5-4: Operational cost increase with year, current dollars

3. Levelized annual fixed charges are straightforward, since we are given the levelized fixed charge rate. We re-emphasized here that the problem indicated that the FCR

was computed using a nominal discount rate, therefore the specified “20%” (of the overnight cost) produces a number stream that reflects inflation (the fact that this cost is not increasing should not lead us to believe inflation is not included in it; it is included - it has just been levelized). Therefore we may obtain that

$$\text{FixedCharges}(t) = \text{FixedChargeRate} * \text{Investment}$$

as illustrated in Fig. 5-5.

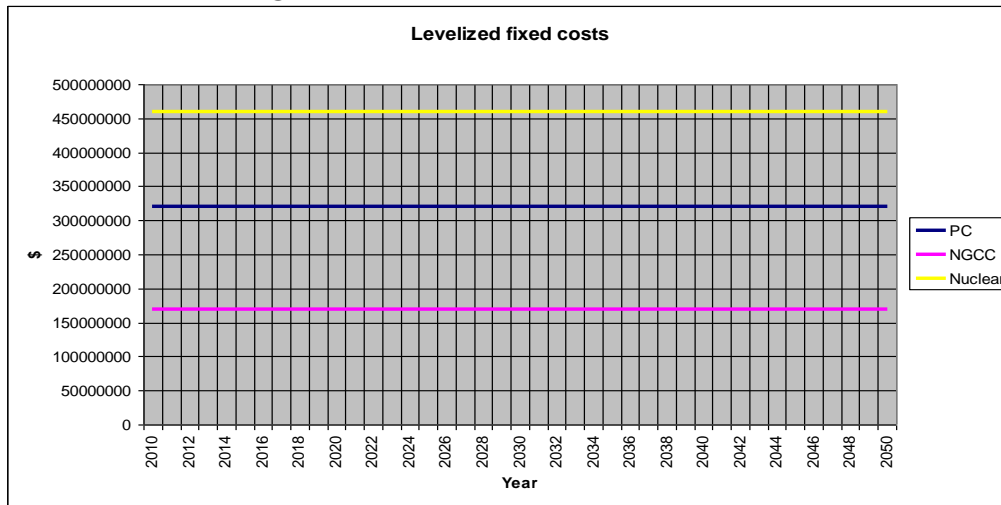


Figure 5-5: Levelized annual fixed charges with year, current dollars

4. Total annual costs of the plants are given by:

$$\text{TotalCost}(t) = \text{OpCost}(t) + \text{FixedCharges}(t)$$

as illustrated in Fig. 5-6.

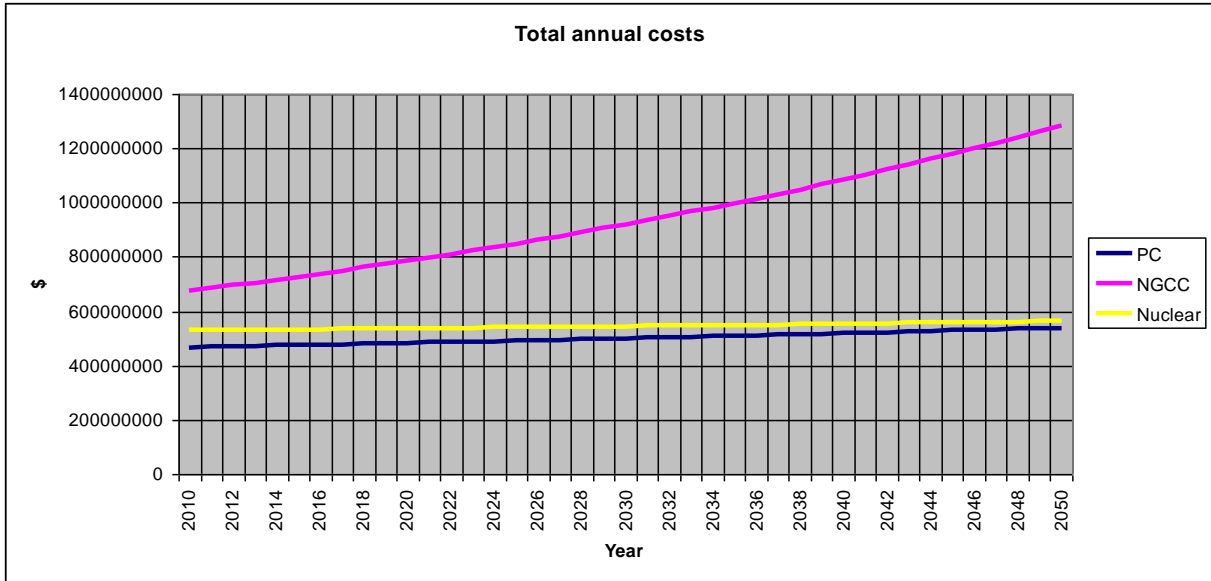


Figure 5-6: Total annual costs with year, current dollars

5. The present value of each plant’s investment + operational costs:

We note that the investment costs are included in the levelized fixed charges. Thus, we compute the desired present value by finding the present worth of each year’s total cost and then summing all of the present worths, i.e.,

$$P = \sum_{t=1}^{40} \text{TotalCost}(t) \times \frac{1}{(1+i)^t}$$

where the nominal discount rate is used, since the values of Fig. 5-6 are current values (they already reflect inflation). The nominal discount rate is $i=8\%$. Using the above formula, we sum the present values of each year’s cost to obtain:

PC	NGCC	Nuclear
6,260,941,978	10,407,721,559	6,945,241,446
<p>\$6.26 billion for the coal plant, \$10.4 billion for the combined cycle plant, and \$6.94 billion for the nuclear plant.</p>		

6. The levelized value (LARR)

The LARR can be computed as a current-dollar LARR (using nominal discount rate) or as a constant dollar LARR (using real discount rate). Here, we choose to obtain a current-dollar LARR. This is computed from the present worth using the capital recovery factor, eq. (7):

$$A = P \times \text{CRF} = P \times \frac{i(1+i)^N}{(1+i)^N - 1}$$

with $i=8\%$ and P as given in #5 above. Results are:

PC	NGCC	Nuclear
525,043,605.4	872,793,210.8	582,429,069.3

\$525 million/year for the coal plant

\$873 million/year for the combined cycle plant and

\$582 million/year for the nuclear plant.....

Comments: The computed LARRs account for investment costs (via FCR) and operational costs for each technology.

However, they do not account for four effects which make combined cycle plants much more attractive:

1. Emissions costs (raises the LARR a lot for the coal plant, some for the NGCC plant, and none for the nuclear plant);
2. Much higher expected overnight costs for nuclear (above analysis assumes \$2300/kW which is very low; today, per Table 2-3, it is well over \$7000/kW);
3. Uncertainties, which are typically greater for technologies having longer lead times (nuclear);

4. Inexpensive gas, from shale (today’s price is only about \$3/MBTU rather than \$8/MBTU, as indicated in Figure 5-3)

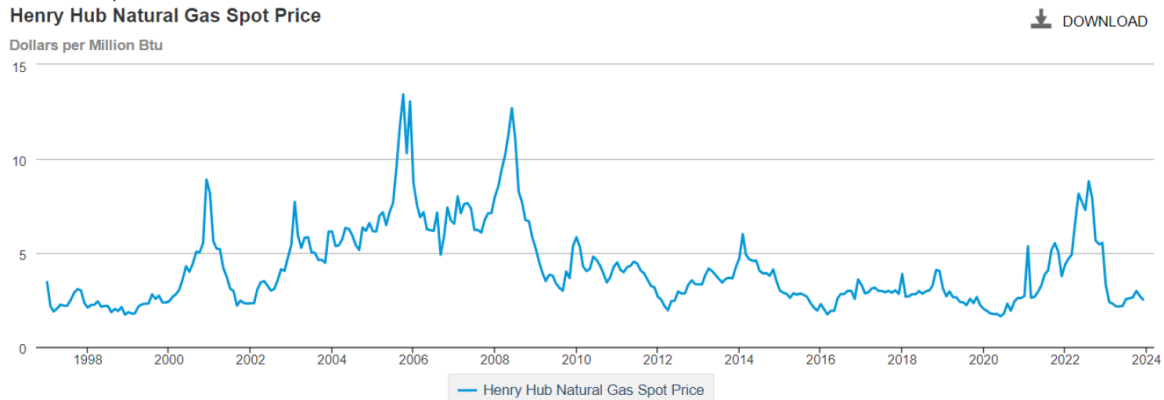


Figure 5-3: Historical gas Henry Hub gas prices (\$/MBTU), 1996-2023

It is also interesting to look at the levelized cost of energy, in \$/MWhr over the lifetime of the plant. To get this, we divide the LARR of each alternative by the annual generated energy. Defining AE as average annual energy provided from the plant, we express the levelized cost of energy (LCOE) as:

$$LCOE = \frac{LARR}{AE} \quad (31)$$

I have performed this calculation in the table below. Note the AE is the same for all three plants, a feature that results from our assumption that all three of these plants have the same capacity factor.

Data	PC plant	NGCC plant	Nuclear plant
LARR	\$525,043,605.4	\$872,793,210.8	\$582,429,069.3
Annual energy, AE	8,760,000 MWhrs	8,760,000 MWhrs	8,760,000 MWhrs
LCOE	\$59.94/MWhr	\$99.64/MWhr	\$66.49/MWhr

One could be more rigorous in assessing present worth costs by including all life-cycle costs in LARR [16], e.g., retirement costs for nuclear would be much larger than the other two.

6 Wind

Repeat the above analysis for a single 1.5 MW wind turbine having a 30-year life. Some references suggest a relatively lower levelized fixed charge rate for wind e.g., [17], suggest a levelized fixed charge rate of 11.6%. This cost of capital to build wind farms is lower than what we used above to build fossil and nuclear plants (typical, because of the greater lead time of the latter). To maintain a “fair” comparison, however, we will continue to use a levelized FCR of 20%.

Data	Wind Turbine
Overnight cost	\$1820/kW
Installation cost	Included in Overnight cost
Levelized fixed charge rate	20%
Plant rating	1.5 MW
Full-load heat rate	NA
2010 fuel price	NA
Fuel price inflation	NA
Capacity factor	0.35
Nominal discount rate	8%

Since we have no fuel costs, our only costs are the annual fixed charges. The initial investment is

$$(\$1820/\text{kW}) * 1500\text{kW} = \$2,700,000$$

The fixed charges (which are in current dollars since the FCR was computed based on the nominal discount rate) are then $0.2 * 2,700,000 = \$540,000$, and since there are no fuel costs, and since we neglect O&M, this is our LARR.

The average annual energy production is

$$\begin{aligned} &= \text{Capacity} * 8760\text{hrs/yr} * \text{CapacityFactor} \\ &= 1.5\text{MW} * 8760\text{hrs/yr} * .35 = 4599\text{MWhrs} \end{aligned}$$

The LCOE is then

$$LCOE = \frac{\text{LARR}}{\text{AE}} = \frac{540000}{4599} = \$117.42 / \text{MWhr}$$

=====
Let's now consider that the fixed charge rate is only 11.6%, as indicated in [17].

Then the fixed charges are $0.116 * 2,700,000 = \$313,200$, which is our LARR. We have the same average annual energy production of 4599 MWhr, therefore

$$LCOE = \frac{\text{LARR}}{\text{AE}} = \frac{313,200}{4599} = \$68.10 / \text{MWhr}$$

=====
Let's consider that we retain our 20% FCR but move to a better wind regime so that our capacity factor is 0.40. Then our average annual energy production is $1.5 * 8760 * 0.4 = 5256$ MWhrs.

With a 20% fixed charge rate, we get

$$LCOE = \frac{LARR}{AE} = \frac{540000}{5256} = \$102.74 / MWhr$$

With a 0.40 capacity factor and an 11.6% fixed charge rate, we get

$$LCOE = \frac{LARR}{AE} = \frac{313,200}{5256} = \$59.59 / MWhr$$

Now let's use a 0.40 capacity factor and an 11.6% fixed charge rate; in addition, I will change the overnight cost to \$1200/kW, so that the initial investment is

$$(\$1200/kw) * 1500kW = \$1,800,000$$

The fixed charges are then $0.116 * 1,800,000 = \$208,800$, and

$$LCOE = \frac{LARR}{AE} = \frac{208,800}{5256} = \$39.72 / MWhr$$

The very best onshore regime may have a capacity factor of 0.5. Using this with an 11.6% fixed charge rate, at \$1200/kW, the initial investment is again \$1,800,000, but the average annual energy production is

$$\begin{aligned} &= \text{Capacity} * 8760 \text{hrs/yr} * \text{CapacityFactor} \\ &= 1.5 \text{MW} * 8760 \text{hrs/yr} * .50 = 6570 \text{MWhrs} \end{aligned}$$

And the LCOE is

$$LCOE = \frac{LARR}{AE} = \frac{208,800}{6570} = \$31.78 / MWhr$$

Let's compare all of our wind calculations to those we did for coal, natural gas, and nuclear:

Resource	LCOE
PC plant	\$59.94/MW hr
NGCC plant	\$99.64/MW hr
Nuclear plant	\$66.49/MW hr
Wind, CF=0.35, FCR=20%, \$1820/kW	\$117.42/MW hr
Wind, CF=0.35, FCR=11.6%, \$1820/kW	\$68.10/MW hr
Wind, CF=0.40, FCR=20%, \$1820/kW	\$102.74/MW hr
Wind, CF=0.40, FCR=11.6%, \$1820/kW	\$59.59/MW hr
Wind, CF=0.40, FCR=11.6%, \$1200/kW	\$39.72/MW hr
Wind, CF=0.50, FCR=11.6%, \$1200/kW	\$31.78/MW hr

Some comments that pertain to these data (but not necessarily today's actual data):

1. Natural gas has a high LCOE because of our assumed high fuel price, and our assumption that gas price would increase 2% / yr.
2. Even at a good capacity factor (40%), wind at 20% FCR rate is not a good investment.
3. At a 35% capacity factor and a 11.6% FCR, we see that the LCOE for wind is only \$68.10/MW hr. If we subtract off from this the 2.2¢/kW hr Production Tax Credit available in 2010, PTC (\$22/MW hr) we see \$46.10/MW hr, which explains why many utilities invested so heavily in wind when the PTC was in play.
4. At a 40% capacity factor and a 11.6% FCR, we see that the LCOE for wind is only \$39.72/MW hr, which is lower than nuclear, gas, and coal even without the PTC.
5. The very lower end of the LCOE range for wind, at \$31.78, is towards the lower end of the range given by Lazard's 2020 cost of energy data [18], per the figure below. Also, note from the below figure that wind, utility-scale solar PV, and gas CC are the most economic resources to build. Some wind even outperforms already-built coal, nuclear, and gas CC plant (the diamonds).

Levelized Cost of Energy Comparison—Unsubsidized Analysis

Selected renewable energy generation technologies are cost-competitive with conventional generation technologies under certain circumstances

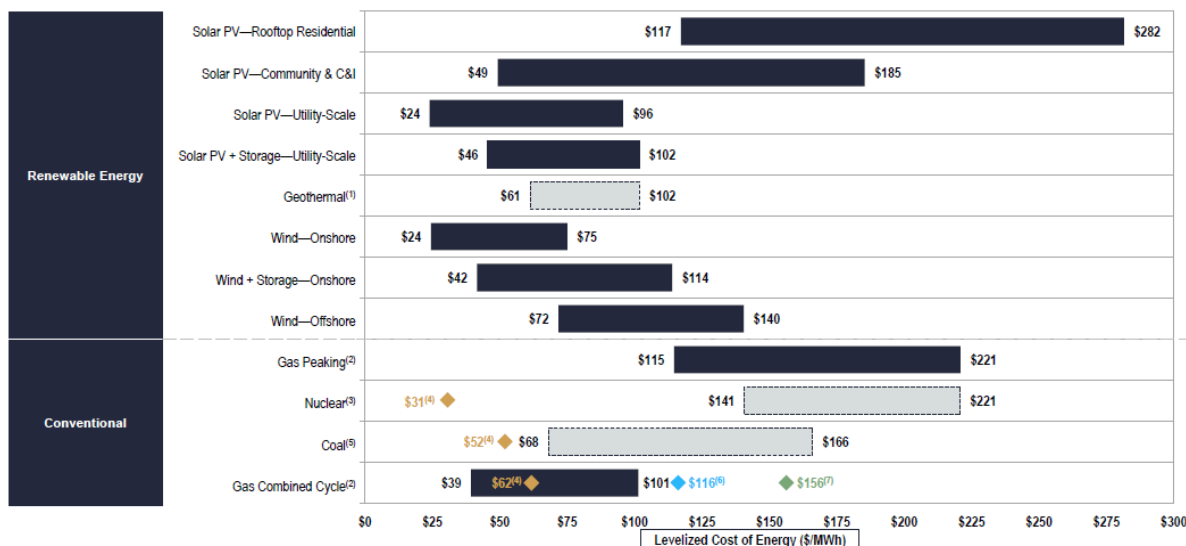


Source: Lazard estimates.
 Note: Here and throughout this presentation, unless otherwise indicated, the analysis assumes 60% debt at 8% interest rate and 40% equity at 12% cost. Please see page titled "Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital" for cost of capital sensitivities. These results are not intended to represent any particular geography. Please see page titled "Solar PV versus Gas Peaking and Wind versus CCGT—Global Markets" for regional sensitivities to selected technologies.
 (1) Unless otherwise indicated herein, the low case represents a single-axis tracking system and the high case represents a fixed-tilt system.
 (2) Represents the estimated implied midpoint of the LCOE of offshore wind, assuming a capital cost range of approximately \$2,600 – \$3,675/kW.
 (3) The fuel cost assumption for Lazard's global, unsubsidized analysis for gas-fired generation resources is \$3.45/MMBTU.
 (4) Unless otherwise indicated, the analysis herein does not reflect decommissioning costs, ongoing maintenance-related capital expenditures or the potential economic impacts of federal loan guarantees or other subsidies.
 (5) Represents the midpoint of the marginal cost of operating fully depreciated gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas combined cycle or coal asset is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating gas combined cycle, coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed operating expenses are based on upper- and lower-quartile estimates derived from Lazard's research. Please see page titled "Levelized Cost of Energy Comparison—Renewable Energy versus Marginal Cost of Selected Existing Conventional Generation" for additional details.
 (6) High end incorporates 90% carbon capture and storage. Does not include cost of transportation and storage.
 (7) Represents the LCOE of the observed high case gas combined cycle inputs using a 20% blend of "Blue" hydrogen, (i.e., hydrogen produced from a steam-methane reformer, using natural gas as a feedstock, and sequestering the resulting CO₂ in a nearby saline aquifer). No plant modifications are assumed beyond a 2% adjustment to the plant's heat rate. The corresponding fuel cost is \$5.20/MMBTU.
 (8) Represents the LCOE of the observed high case gas combined cycle inputs using a 20% blend of "Green" hydrogen, (i.e., hydrogen produced from an electrolyzer powered by a mix of wind and solar generation and stored in a nearby salt cavern). No plant modifications are assumed beyond a 2% adjustment to the plant's heat rate. The corresponding fuel cost is \$10.05/MMBTU.

The above analysis tells us that we need to do what we can to bring down cost of capital, insurance, property taxes, income taxes, and depreciation (the last one by increasing the expected life). One way to reduce the cost of capital is by paying more money earlier in time.

A more recent Lazard LCOE analysis is provided below [19]. Levelized Cost of Energy Comparison—Unsubsidized Analysis

Selected renewable energy generation technologies are cost-competitive with conventional generation technologies under certain circumstances



One often sees the LCOE calculation in the literature as [20]:

$$\text{LCOE} = \frac{\text{FCR} * \text{ICC} + \text{LRC}}{\text{AEP}} + \text{AVOM} \quad (32)$$

where

- FCR is the levelized fixed charge rate (per year)
- ICC is the initial capital cost, in \$
- LRC is the levelized retirement cost, in \$/yr
- AEP is the annual energy production, in kWhr
- AVOM is the annual variable O&M, in \$/kWhr.

In our calculations we ignored LRC and included only the fuel cost portion of the AVOM (fixed O&M are included in the FCR).

7 Economic analysis in project evaluation

Here, we assume we have identified a limited number of project alternatives that can accomplish the stated objective. We desire to compare the alternatives. Each such analysis is different, but there are some common steps, as follows:

1. State objective
2. Define alternatives: Include the “do-nothing” alternative. Each admitted alternative should (a) be feasible and (b) accomplish the objective.
3. Identify incremental costs of each alternative: These are the costs that are not incurred with all alternatives. Costs that will be incurred in the future and are common to all the alternatives are of no significance since they will occur regardless of which alternative course of action is chosen. Similarly, costs that have occurred in the past are usually irrelevant in the

economic analysis because no future course of action can change the fact that these costs have already been incurred.

4. Choose study period (planning horizon): The study period represents that period of time over which costs are analyzed. The study period must extend far enough into the future to include all incremental costs for the alternatives being analyzed.

One interesting difficulty often arises in the above type of analysis that requires further discussion here.

Since alternatives are compared on the basis of total project cost, the alternatives must be defined so that they provide

- equal service (output, capacity)
- for equal lengths of time.

Otherwise, an alternative providing less service, or the same service for less time, may appear to result in lower costs and therefore might be chosen as the best alternative when in fact this alternative may result in greater total costs to the customers than one or more other alternatives.

7.1 Choosing study period

Two methods for choosing the study period that address the possibility that different alternatives may have different service times are as follows:

1. Salvage value approach: In this approach, the study period is set equal to the estimated service life of the alternative with the shortest service life. Then we assign salvage values at the end of the study period for those alternatives

that have service lives greater than the study period. These salvage values should reflect the value of the lost service over the remaining service lives of the alternatives due to the hypothetical early retirement of these facilities.

2. Additional service approach: In this approach, the study period is set equal to the estimated service life of the alternative with the longest service life. Then we assign additional service from another source for the alternatives with service lives less than the study period.

Example: A new power plant is required to meet future electric load. There are two alternatives:

Alternative A:

Service life=30 years

Capacity=100 MW

Alternative B:

Service life=20 years

Capacity=100 MW

- Approach 1: Choose a 20 year study period with salvage value for Alternative A:
- Approach 2: Choose a 30 year period assuming you will establish a 10 year contract to buy firm power from a neighboring generation owner for the last decade.

This issue is a specific case of a more general problem in planning called “end effects.” We will look at end effects more closely later in the course.

7.2 Equalizing service provided

Here, one must provide for service from another source if alternatives do not have the same output per year. That is, if two alternatives differ in service for some years, the cost of

obtaining service elsewhere should be included as a cost to the alternative which provides less output.

Example: A new power plant is required to meet future electric load. There are two alternatives:

Alternative A:

Service life=20 years

Capacity=100 MW

Alternative B:

Service life=20 years

Capacity=50 MW

- Approach 1: Assume Alternative B is comprised of two 50 MW units, rather than one.
- Approach 2: Assume Alternative B must obtain a 20 year contract to buy firm power from a neighboring generation owner over the life of the project.

8 Screening Curves

Figure 8-1, which shows LCOE as a function of capacity factor for two technologies, is inconsistent with intuition. Why?

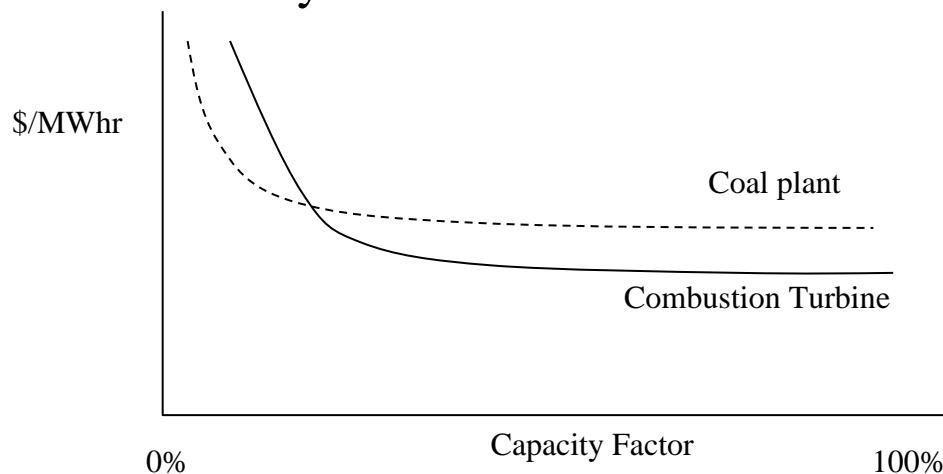


Figure 8-1: Illustration of wrong screening curves

The reason is that the curves are computing the cost of energy from each of the two technologies as a function of capacity factor, and it is saying:

- If you want to use a generator at low capacity factor, then the coal plant is the most economic.
- If you want to use a generator at high capacity factor, then the CT is the most economic.

This is counter to intuition, since coal plants are typically used as base-loaded facilities (and must be therefore more economic at high capacity factors), and CTs are typically used only in peak conditions (and must be therefore more economic at low capacity factors).

An more intuitive pair of curves is show in Figure 8-2.

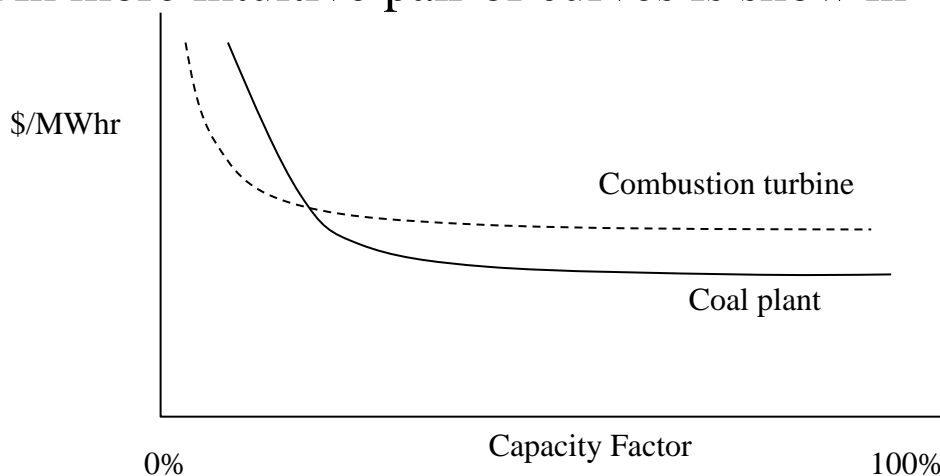


Figure 8-2: Illustration of a correct screening curve

These curves are called screening curves; they provide a way to view tradeoffs between technologies in terms of investment costs and operating costs.

The EPRI application called EGEAS [21, 22, 23], which is used by the Midcontinent ISO and other organizations around the nation, has functionality for developing screening curves. Ref [23] is a very useful document; it is publicly available at the given URL.

Screening curves are a simple way of performing preliminary screening of generation alternatives in planning, without accounting for system reliability contributions of the various possible generation investments, or for the influence of transmission.

In the screening curve approach, the levelized cost of energy (\$/MWhr) for all planning alternatives are plotted as a function of capacity factor. The resulting screening curves provide a quick comparison of investment alternatives, allowing dominated alternatives to be identified and excluded from further consideration.

Annual time periods are generally used for screening curve studies, but other period lengths are possible. Eq. (33) defines the cost expression for this approach:

$$\$/\text{MWhr} = \underbrace{\frac{\text{Annual Fixed Cost (\$/MW)}}{(8760\text{hrs}) \times \text{Cap Factor}}}_{\text{TERM 1}} + \underbrace{\text{Var Costs (\$/MWhr)}}_{\text{TERM 2}} \quad (33)$$

where the Annual Fixed Cost is obtained from the overnight investment cost via the capital recovery factor:

$$A = P \times \text{CRF} = P \times \frac{i(1+i)^N}{(1+i)^N - 1} \quad (34)$$

In our example (below), we will assume real discount rate $i=0.10$ and $N=40$ years for all technologies. A more rigorous analysis would have N technology-specific.

Observe that (33) will result in different ratios of term 1 to term 2, depending on the capacity factor:

- Low capacity factors result in term 1 dominating term 2, so that technologies with low investment costs look very good, even if they have high operational costs.
- High capacity factors result in term 2 dominating term 1, so that technologies with low O&M costs look very good.

A rough way of saying the above is,

- if you are not going to run the unit much (low CF), then the unit should be cheap to build, but you can have high fuel cost; and
- if you are going to run the unit a lot (high CF), then the unit should be cheap to run, but you can have higher build cost.

It is important to realize that we are computing (33) as *a function of capacity factor* (so as to draw the screening curves), and not based on the expected capacity factor for each technology.

Also, compare (33) with that for levelized cost of energy equation (32), repeated here for convenience:

$$LCOE = \frac{FCR * ICC + LRC}{AEP} + AOM \quad (32)$$

where

- FCR is the levelized fixed charge rate (per year)
- ICC is the initial capital cost, in \$
- LRC is the levelized retirement cost, in \$/yr
- AEP is the annual energy production, in kWhr
- AOM is the annual O&M, in \$/kWhr.

and you find that it is the same.

The difference is that (33) is given as an explicit function of capacity factor, whereas this dependence is implicit in (32) (via annual energy production, AEP).

Let's develop screening curves for the data given below. Observe that oil-fired plants are assumed to be very inexpensive to build.

Technology	Variable Cost Data					Fixed Cost Data		
	Heat Rate Mbtu/MWhr	Fuel Cost \$/Mbtu	Emission Rate lb CO ₂ /Mbtu	Var Cost @ 0\$/lbs CO ₂	Var Cost @ \$50/lb CO ₂	Investment Cost \$/MW	Annual, 40 year life \$/kW	
Nuclear	10.4	0.75	0	7.8	7.8	2569000	29.98909083	
Pulverized Coal	9.2	1.8	215	16.56	66.01	2223000	25.95007743	
NGCC	7.5	8	117	60	81.9375	984000	11.48667395	
CT	10.8	8	117	86.4	117.99	685000	7.996312657	
Wind	0	0	0	0	0	1966000	22.950001	
Oil	10.1	12	162	121.2	162.105	500000	5.836724567	
IGCC	8.765	1.8	199	15.777	59.382875	2569000	29.98909083	
IGCC w/CarbSeq	10.781	1.8	20	19.4058	24.7963	3376000	39.40956428	
Solar	0	0	0	0	0	5132000	59.90814096	

I posted two spreadsheets on the website, one giving calculations for no CO₂ tax and one giving calculations for a \$50/ton CO₂ tax.

Figure 8-3 shows screening curves for the 0-dollar carbon tax. The vertical axis is \$/MWhr and the horizontal axis is capacity factor. One observes that

- For very low capacity factors (below 0.15), CTs and oil-fired units are best.
- For slightly higher capacity factors (0.15 to 0.2), NGCC are best.
- For capacity factors above 0.2, wind is best. Of course, wind cannot achieve capacity factors above about 0.35-0.40, and so above these capacity factors, if we ignore wind, we observe that nuclear, coal, and IGCC are best (these would be the base-loaded plants).

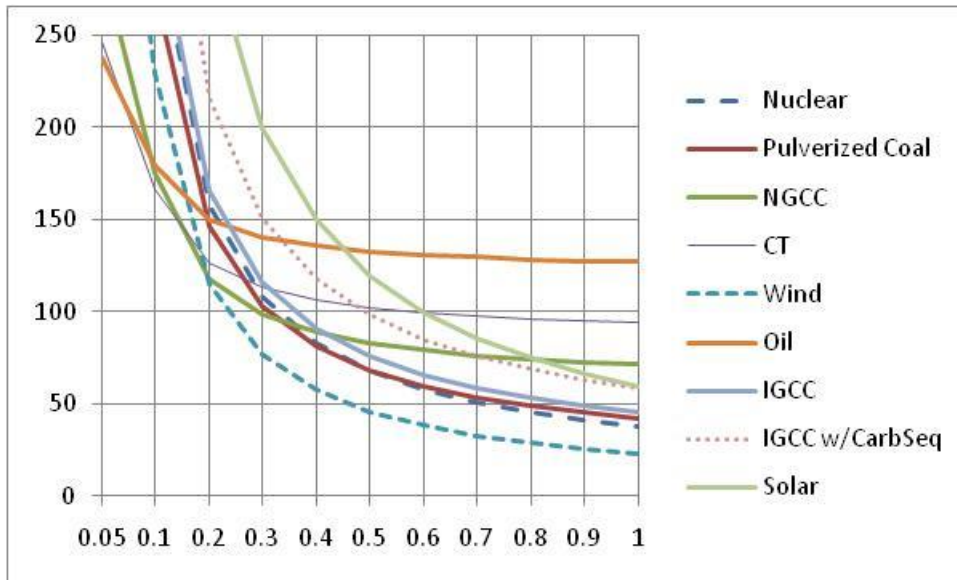


Figure 8-3: \$0 carbon tax

Figure 8-4 shows screening curves for a \$50/ton carbon tax. Important differences are that oil is no longer attractive, nuclear is the clear winner for high capacity factors, but solar (if it could operate at such high capacity factors) and IGCC w/CarbSeq now overtake coal and IGCC for the second and third most attractive base-loaded plants.

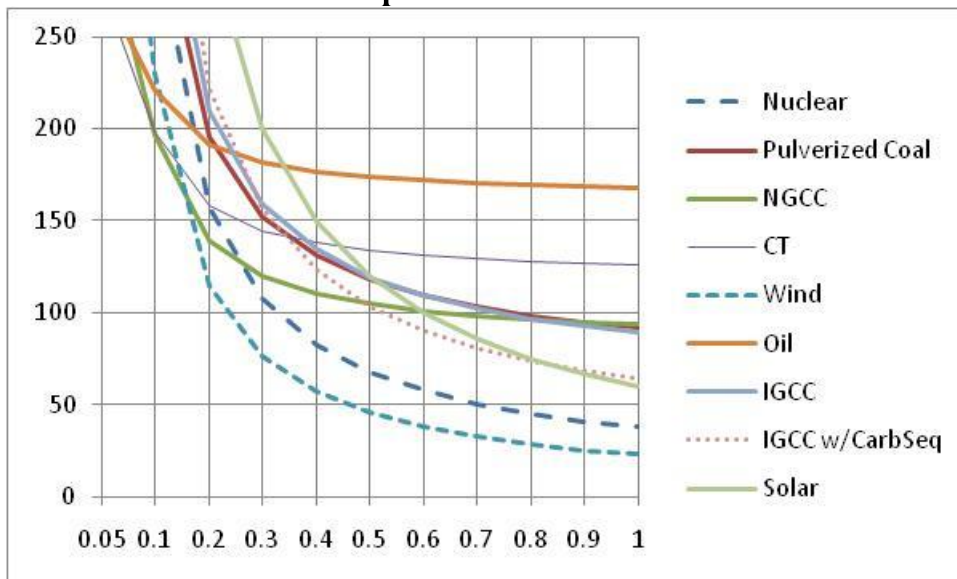


Figure 8-4: \$50/ton carbon tax

These curves can be compared to some that MISO engineers developed, Figure 8-5, which assumes no CO₂ tax. These MISO curves were developed based on cost data from around 2008.

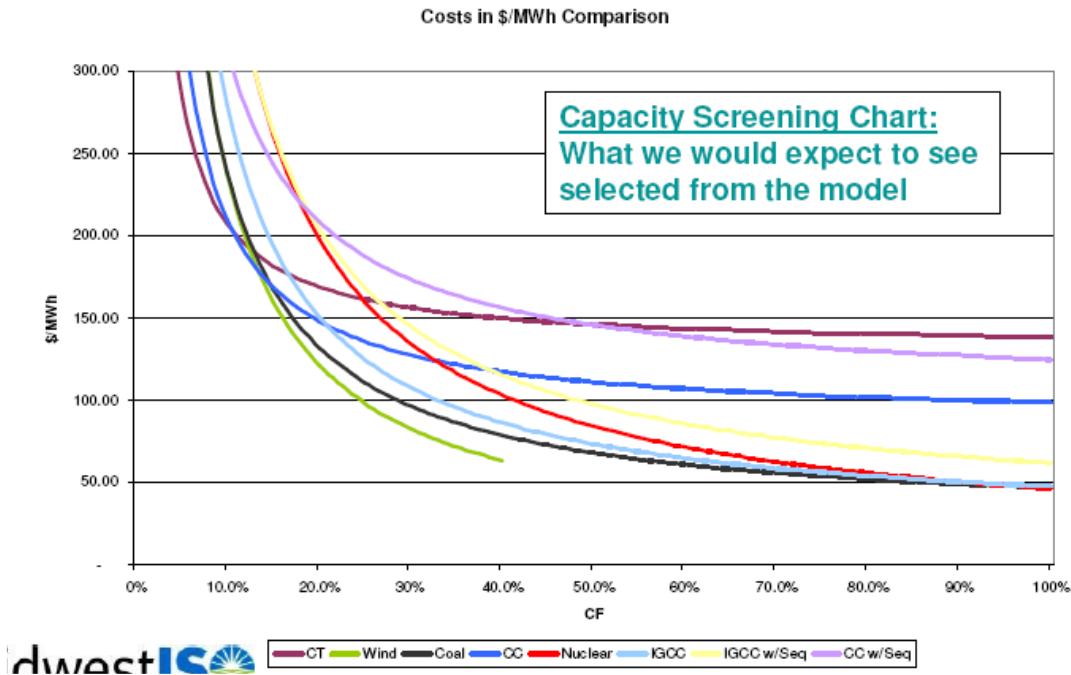


Figure 8-5: Screening curves developed by MISO engineers

Screening curves may be used together with an annualized load duration curve to identify the energy to be supplied by each technology, assuming there are no other influences beyond those accounted for in the screening curves, as shown in Figure 8-6.

Figure 8-6 can be understood as follows:

- The bold dark curve traces the curve corresponding to the technology that is least cost for the given range of capacity factor.

- If we assume each unit always runs at full capacity, then capacity factor can be interpreted as the fraction of time the unit will run during the year. This is shown below.

$$CF = \frac{AnnualEnergy}{MaxPossEnergy} = \frac{CF \times P \times T}{P \times T} = \frac{P \ CF \times T}{P \ T} = \frac{CF \times T}{T}$$

- The load duration curve provides the fraction of time the load will exceed a certain value.
- The range of load each technology will supply can be identified by mapping the least-cost technology to the load duration curve.

Obtaining the annual energy provided by each plant offers a mechanism for approximating the production costs each technology would contribute for a given power system (where the “given power system” is specified by the load duration curve).

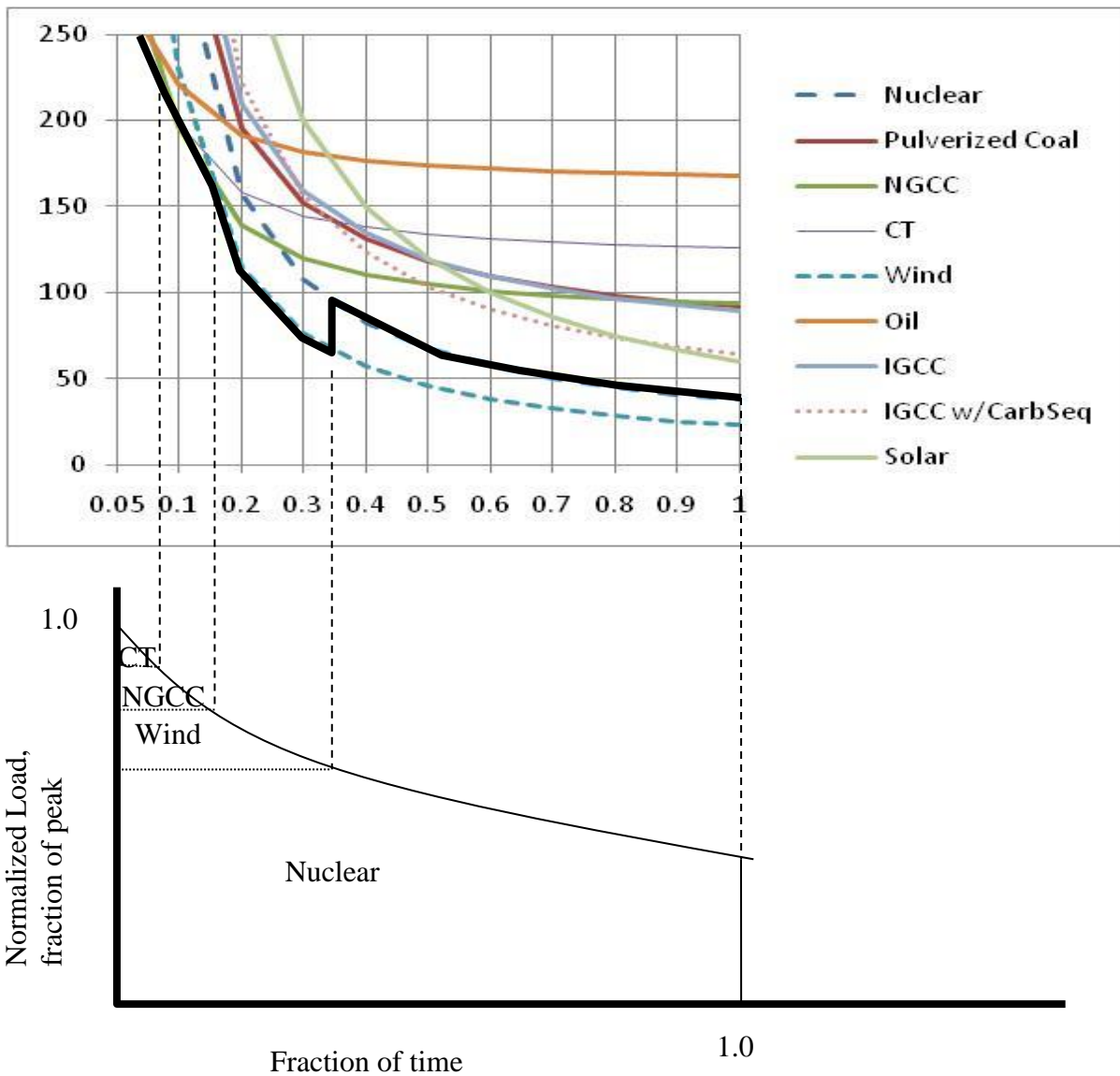


Figure 8-6: Use of screening curves with annualized load duration curve

Screening curve analysis is not an adequate substitute for detailed production cost or expansion planning analysis since forced outages, unit sizes, variability, system reliability (including portfolio diversity) and other issues are not treated directly with screening

curves. A good discussion of strengths and weaknesses of screening curves is in [3, chap 10].

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