How to Estimate Utility Costs

Utility estimates are often complicated because they depend on both inflation and energy costs. This simplified approach offers a two-factor utility-cost equation and the relevant coefficients for a number of utilities.

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Typical process utilities include electricity, process steam, refrigerants, compressed air, cooling water, heated water, hot oil, process water, demineralized water, municipal water, and river, lake, or ocean water. For preliminary cost estimates, waste disposal cost can also be treated like a utility expense.

Unlike capital, labor, and other expenses, utility prices do not correlate simply with conventional inflationary indexes, because basic energy costs vary erratically, independent of capital and labor. In essence, utility price is linked to two separate variables — inflation and energy cost. Elements of manufacturing expense that depend on labor and capital follow inflationary metrics like the CE Plant Cost Index (CE PCI). Energy cost, such as that for fuel in an electrical or steam generating plant, is like a raw material whose price can vary widely and erratically. To reflect this dual dependence, we need a two-factor utility cost equation such as the following:

$$ C_{S,U} = a (CE PCI) + b (CS_f) \tag{1} $$

where $C_{S,U}$ is the price of the utility, $a$ and $b$ are utility cost coefficients, $CS_f$ is the price of fuel in $\$/GJ, and CE PCI is an inflation parameter for projects in the U.S.¹

Deriving the coefficients
To derive Coefficients $a$ and $b$, a manufacturing cost analysis must be prepared for a given utility.² Electric power price, for instance, includes raw material costs, labor, supervision, maintenance, overhead, and a number of other items that determine total manufacturing expense and, ultimately, selling price. In such a list, individual cost items can be divided into two categories, those dependent on normal inflation and those dependent

¹ Evaluated monthly by the staff of Chemical Engineering and printed along with historical values of this and other indexes on the last page of each issue.

² See Vatavuk [1] or Chapter 6 of Reference [2] for information on how manufacturing costs are evaluated.

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**NOMENCLATURE**

- $a$ The first utility cost coefficient in Equation [1], which reflects inflation-dependent cost elements
- $A$ Annual utility cost, $(U.S.)/yr$
- $b$ The second utility cost coefficient in Equation [1], which reflects energy-dependent cost elements
- $CS_f$ Fuel price for use in Equation [1], $(U.S.)/GJ$
- $CS_U$ Utility price $(\$ per unit designated in Table 1)$
- $f_o$ Operating or online factor (dimensionless)
- HHV Higher heating value
- (see Note h to Table 1)
- LHV Lower heating value
- (see Note i to Table 1)
- $m$ Mass flowrate, kg/s
- $p$ Pressure: barg (bar gage) for steam; bara (bar absolute) for compressed air
- $P$ Power consumption, kW
- $q$ Volumetric flowrate, m³/s for liquids or Nm³/s for gases
- $Q_c$ Cooling capacity in a refrigeration system, kJ/s
- $Q_H$ Heating capacity of a heat source, kJ/s

**Subscripts**

- $c$ Cooling
- $cw$ Cooling water
- $e$ Electricity
- $H$ Heating
- $refrig$ Refrigerant
- $S$ Price
- waste treat Waste treatment

**FIGURE 1.** Prices for fuels on an energy-equivalent basis. Numbers are U.S. averages, delivered. [From U.S. Dept. of Energy (www.eia.doe.gov). The Oil and Gas Journal (www.ogjonline.com), and informal sources. Values for gasoline do not include taxes, which may add from 30 to 50%, depending on the location.]
<table>
<thead>
<tr>
<th>Cost coefficients</th>
<th>Electricity, $/kWh</th>
<th>Wastewater Treatment[^a], $/m³</th>
<th>Water Desalination[^a]</th>
<th>Gas Emissions Treatment[^a], $/Nm³</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Purchased from outside</strong></td>
<td>1.3 × 10⁻⁴</td>
<td>0.010</td>
<td>Process module</td>
<td>0.0001 + 2 × 10⁻⁷ q⁻¹</td>
</tr>
<tr>
<td><strong>Onsite power charged to process module</strong></td>
<td>1.4 × 10⁻⁴</td>
<td>0.011</td>
<td>Grass-roots plant</td>
<td>0.00005 + 2 × 10⁻⁷ q⁻¹</td>
</tr>
<tr>
<td><strong>Onsite power charged to grass-roots plant</strong></td>
<td>1.1 × 10⁻⁴</td>
<td>0.011</td>
<td>Process module</td>
<td>0.0007 + 2 × 10⁻⁴ q⁻¹</td>
</tr>
<tr>
<td><strong>Compressed and Dried Air[^b], $/Nm³</strong></td>
<td>(0.1 &lt; q &lt; 100 Nm³/s; 2 &lt; p &lt; 35 bara)</td>
<td></td>
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<tr>
<td><strong>Process module</strong></td>
<td>5.0 × 10⁻⁶·q·0.30[(ln p)]</td>
<td>9.0 × 10⁻⁴·[(ln p)]</td>
<td>Grass-roots plant</td>
<td>0.0003 × 2 × 10⁻⁴ q⁻¹</td>
</tr>
<tr>
<td><strong>Grass-roots plant</strong></td>
<td>4.5 × 10⁻⁶·q·0.30[(ln p)]</td>
<td>9.0 × 10⁻⁴·[(ln p)]</td>
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<tr>
<td><strong>Membrane Processes (see water desalination costs above)</strong></td>
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<tr>
<td><strong>Process Steam[^c], $/kg</strong></td>
<td>(1 &lt; p &lt; 46 barg; 0.06 &lt; mₚ &lt; 40 kg/h)</td>
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<td></td>
<td></td>
</tr>
<tr>
<td><strong>Process module</strong></td>
<td>2.7 × 10⁻⁵ mₚ⁻⁰.₃</td>
<td>0.0034 mₚ⁻⁰.₃⁵</td>
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<tr>
<td><strong>Grass-roots plant</strong></td>
<td>2.3 × 10⁻⁵ mₚ⁻⁰.₃</td>
<td>0.0034 mₚ⁻⁰.₃⁵</td>
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<tr>
<td><strong>Cooling Water[^d], $/m³</strong></td>
<td>(0.01 &lt; q &lt; 10 m³/s)</td>
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<td></td>
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</tr>
<tr>
<td><strong>Process module</strong></td>
<td>0.0001 + 3.0 × 10⁻⁴ q⁻¹</td>
<td>0.003</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Grass-roots plant</strong></td>
<td>0.0007 + 2.5 × 10⁻⁴ q⁻¹</td>
<td>0.003</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Demineralized (boiler feed) Water[^e], $/m³</strong></td>
<td>(0.001 &lt; q &lt; 1.0 m³/s)</td>
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<td></td>
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<tr>
<td><strong>Process module</strong></td>
<td>0.007 + 2.5 × 10⁻⁴ q⁻⁰.₆</td>
<td>0.04</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Grass-roots plant</strong></td>
<td>0.005 + 2.5 × 10⁻⁴ q⁻⁰.₆</td>
<td>0.04</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Drinking Water[^f], $/m³</strong></td>
<td>(0.001 &lt; q &lt; 10 m³/s)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Process module</strong></td>
<td>7.0 × 10⁻⁴ + 3.0 × 10⁻⁴ q⁻⁰.₆</td>
<td>0.02</td>
<td></td>
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<tr>
<td><strong>Grass-roots plant</strong></td>
<td>5.0 × 10⁻⁴ + 2.5 × 10⁻⁴ q⁻⁰.₆</td>
<td>0.02</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Natural Water, Pumped and Screened[^g], $/m³</strong></td>
<td>(0.001 &lt; q &lt; 10 m³/s)</td>
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</tr>
<tr>
<td><strong>Process module</strong></td>
<td>1.0 × 10⁻⁴ + 3.0 × 10⁻⁴ q⁻⁰.₆</td>
<td>0.003</td>
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<td></td>
</tr>
<tr>
<td><strong>Grass-roots plant</strong></td>
<td>7.0 × 10⁻⁴ + 2.5 × 10⁻⁴ q⁻⁰.₆</td>
<td>0.003</td>
<td></td>
<td></td>
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<tr>
<td><strong>Refrigerant, $/k/J cooling capacity[^h]</strong></td>
<td>(1 &lt; Qₑ &lt; 1,000 k/J; 0 &lt; T &lt; 300 K)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Process module</strong></td>
<td>0.0014 + 4.0 × 10⁻⁵ q⁻⁰.₅</td>
<td>0.02</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Grass-roots plant</strong></td>
<td>0.0013 + 3.0 × 10⁻⁵ q⁻⁰.₅</td>
<td>0.02</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Seawater[^i] (35,000–40,000 ppm tds in feed), $/m³</strong></td>
<td>(0.001 &lt; q &lt; 1.0 m³/s)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Process module</strong></td>
<td>0.0015 + 6.0 × 10⁻⁴ q⁻⁰.₆</td>
<td>0.13</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Grass-roots plant</strong></td>
<td>0.0012 + 4.5 × 10⁻⁴ q⁻⁰.₆</td>
<td>0.13</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hot Water, Hot Oil, or Molten-Salt Heat Transfer Media, $/k/J heating capacity[^j]</strong></td>
<td>(100 &lt; Qₑ &lt; 20,000 k/J; 350 &lt; T &lt; 850 K)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Process module</strong></td>
<td>7.0 × 10⁻⁷ Qₑ·¹·₃·[(T⁻²)]</td>
<td>6.0 × 10⁻⁷·[(T⁻²)]</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Grass-roots plant</strong></td>
<td>6.0 × 10⁻⁷·[(T⁻²)]</td>
<td>6.0 × 10⁻⁷·[(T⁻²)]</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
- a. Cₑf is the price of fuel that partners with Coefficient b, is based on the higher or gross heating value. For electrical power, compressed air, refrigerant, cooling water, and other auxiliary facilities where electricity is used to drive pumps and compressors, it is the price of fuel at the electric power station. For steam, it is the price of boiler fuel at the plant. Historic values for Cₑf are plotted in Figure 1.
- b. Coefficients apply to ranges of q and p indicated, where q is total auxiliary airplant capacity (Nm³/s) and p is delivered pressure of air (bara).
- c. Use price of fuel burned in the boiler for Cₑf; mₚ is total auxiliary boiler steam capacity (kg/s).
- d. q is total water capacity (m³/s).
- e. Qₑ is total auxiliary cooling capacity (kJ/s), T is absolute temperature (K).
- f. QₑT is total auxiliary heating capacity (kJ/s), T is absolute temperature (K).
- g. Use these numbers advisedly. Waste disposal costs depend on local public attitudes and other political factors that are capricious and location-sensitive. See Perry [3], page 25-101 for typical U.S.-regional variations.
- h. m is waste flowrate (kg/s). HHV is higher heating value of waste (MJ/L/kg). Note that b is negative in these instances, because waste burning as a supplementary fuel returns a credit.
- i. q is total treatment system flow in normal (273 K, 1 atm) cubic meters per second (Nm³/s). LHV is lower or net heating value in MJ/Nm³. Note that b is negative in these instances, because waste burning as a supplementary fuel returns a credit.

[^a]: CHEMICAL ENGINEERING WWW.CHE.COM APRIL 2006 67
on fuel price. This allows one to calculate values for \( a \) and \( b \). We have done that for a host of utilities. Results are presented in Table 1. Meanwhile, the higher heating values for a number of typical fuels are given in Table 2.

To cover all types of common CPI projects, two additional factors must be considered. First, since capital and labor expenses are not linear functions of capacity, it is necessary to make Coefficient \( a \) dependent on plant size. This reflects the simple fact that relative capital and labor costs per unit of capacity decline as plant size increases. We see this, for instance, in the entry for cooling water in Table 1. In a cooling system designed to handle 1 m³/s, water will be more expensive per cubic meter than from a plant designed to handle 10 m³/s, and the expression for Coefficient \( a \) reflects that.

Use of Equation (1) calls for judgment. If your module includes a heat exchanger that consumes 0.1 m³/s and there are no other uses of cooling water on site, you will simply use 0.1 m³/s for \( q \) in the equation for Coefficient \( a \). If, on the other hand, the exchanger is part of a larger plant where total cooling-water needs are 6 m³/s, it is the appropriate value for \( q \) in the equation (Table 1) for Coefficient \( a \).

Wisdom also tells us there is a limit on practical plant size. In a larger complex where total cooling-water demand is greater than 10 m³/s, that or a lesser value should be used for \( q \), because standard cooling systems are limited to 10 m³/s. Greater needs are met with multiple units.

A second consideration hinges on whether your module is a part of a grass-roots facility or an existing plant. For example, water is cooled in what is described as an “offsite facility.”3 If the heat exchanger in question is part of a new project being built, this offsite capital is included in total project cost. If, on the other hand, the exchanger is being added to a plant where adequate offsite facilities are already in place, the costs of the offsite facility have already been paid. To be fair and accurate in assigning costs, an addition should be treated like a customer that purchases utilities from the grass-roots plant.4 Thus, there are two categories in Table 1; one for grass-roots plants and a second for process modules. Grass-roots utility prices are lower because the cost estimate for a heat exchanger in a grass-roots project has already accounted for its share of the cooling-tower capital.

One might ask why equations for utilities like cooling water and compressed air contain a Coefficient \( b \) if no fuel is burned. Consider that electricity is required to power the pumps and compressors involved in delivering these utilities. Fuel is consumed to generate that electricity, and its cost5 must be included in the price for cooling water or compressed air.

Meanwhile, one might also ask why coefficients for self-generated electricity in Table 1 are larger than those for purchased electricity. In general, purchased power is cheaper than onsite power, because large, free-standing electric power plants tend to be more efficient than onsite generating facilities. This supports a rule of thumb that self-generation of electricity is not attractive unless cheap fuel is available or electricity can be co-generated with process steam.

Putting the method to use
To illustrate the use of Equation (1), consider the cost of electricity generated using Number 6 (residual) fuel oil. In mid-2000, the CE PCI was 392, the equivalent price of energy from residual oil was $4/GJ ($27/barrel), and the price of purchased electricity (estimated from Equation (1) with coefficients taken from Table 1) is calculated to be:

\[
C_{\text{e,2000}} = 1.3 \times 10^{-4}(392) + 0.010(4.0) = 0.091/kWh
\]

This agrees closely with the price of electricity charged to large industrial customers in the northeastern U.S., where residual fuel oil was a prominent utility fuel in 2000.

Coal is an important resource in the U.S. because it is abundant and relatively inexpensive. Its use is limited, however, to large power plants where combustion is efficient and clean. With coal at $1.20/GJ, the price of electricity generated from coal in 2000 would have been 6.4 cents per kWh, about two-thirds the price of electricity generated from No. 6 fuel oil that year. Historical price data for coal, oil, and other important fuels are plotted in Figure 1.

Escalating prices for the future
Continuing with the No. 6 fuel-oil example, what will the price of electricity be in 2010? Inflation, estimated at...
On pages 2 to 31 we show how you can turn a storage and shipping drum into a process vessel in next to no time.

Based on Table 1, assuming a CE PCI = 470 and $C_{s,t} = \$4.50/GJ$, the same inflation index and fuel values as in the utility cost estimation illustration on p. 68, $C_{s,refrig} = [0.5(40)-0.9(268)-3] (470) = \$4.0 \times 10^{-6}/kJ$. 

The maximum refrigerant demand rate is 40 kJ/s, and the maximum plant wastewater flowrate is 0.01 m$^3$/s. The waste stream contains both organics and inorganic salts, so tertiary treatment is necessary.

3 to 3.5% per year, foreshadows a CE PCI of 550. Fuel prices, on the other hand, are capricious. Assume that pressure from coal and nuclear energy moderate the recent escapades in oil prices. Extrapolating from the relatively stable 1990s at an annual rate of 4 to 5%, we arrive at a price of about $\$6/GJ$ for No. 6 fuel oil. Accordingly, the 2010 price of electricity from this source is projected to be:

$C_{S,e,2010} = 1.3 \times 10^{-4}(550) + 0.010(6.0) = \$0.132/kWh$

Any projection so many years in the future is highly speculative. Based on historical data for capital costs, the projected CE PCI is reasonable, but there is little evidence to support the projected fuel price. One could easily argue for an energy price that is double or triple that calculated above. This would mean electricity prices of 19 to 25 cents per kWh.

**References**


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