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

Gael D. Ulrich and **Palligarnai T. Vasudevan**
University of New Hampshire

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:

$$C_{S,u} = a\,(CE\ \mathrm{PCI}) + b\,(C_{S,f}) \qquad (1)$$

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

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.

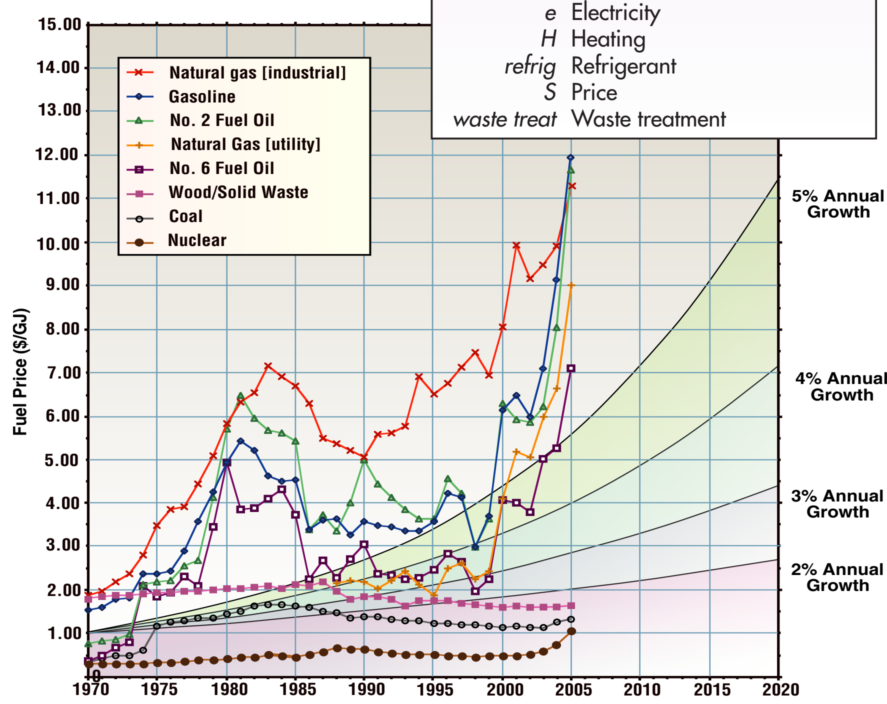

FIGURE 1. Prices for fuels on an energy-equivalent basis. Numbers are U.S. averages, delivered. [From U.S. Dept. of Energy (www.eia.doe.gov). The *Oil and Gas Journal* (www.ogjonline.com), and informal sources. Values for gasoline do not include taxes, which may add from 30 to 50%, depending on the location.]

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

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

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
- $C_{S,f}$ Fuel price for use in Equation [1], \$(U.S.)/GJ
- $C_{S,u}$ 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, m^3/s for liquids or N m^3/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

TABLE 1. UTILITY COST COEFFICIENTS[a]

		Cost coefficients a	Cost coefficients b
Electricity, \$/kWh			
	Purchased from outside	1.3×10^{-4}	0.010
	Onsite power charged to process module	1.4×10^{-4}	0.011
	Onsite power charged to grass-roots plant	1.1×10^{-4}	0.011
Compressed and Dried Air[b], \$/Nm³			($0.1 < q < 100$ Nm³/s; $2 < p < 35$ bara)
	Process module	$5.0 \times 10^{-5} q^{-0.30}(\ln p)$	$9.0 \times 10^{-4}(\ln p)$
	Grass-roots plant	$4.5 \times 10^{-5} q^{-0.30}(\ln p)$	$9.0 \times 10^{-4}(\ln p)$
Instrument Air[b], \$/std m³			
	Process module	1.25×10^{-4}	1.25×10^{-3}
	Grass-roots plant	1.15×10^{-4}	1.25×10^{-3}
Process Steam[c], \$/kg			($1 < p < 46$ barg; $0.06 < m_s < 40$ kg/s)
	Process module	$2.7 \times 10^{-5} m_s^{-0.9}$	$0.0034 p^{0.05}$
	Grass-roots plant	$2.3 \times 10^{-5} m_s^{-0.9}$	$0.0034 p^{0.05}$
Cooling Water[d], \$/m³			($0.01 < q < 10$ m³/s)
	Process module	$0.0001 + 3.0 \times 10^{-5} q^{-1}$	0.003
	Grass-roots plant	$0.00007 + 2.5 \times 10^{-5} q^{-1}$	0.003
Demineralized (boiler feed) Water[d], \$/m³			($0.001 < q < 1.0$ m³/s)
	Process module	$0.007 + 2.5 \times 10^{-4} q^{-0.6}$	0.04
	Grass-roots plant	$0.005 + 2.0 \times 10^{-4} q^{-0.6}$	0.04
Drinking Water[d], \$/m³			($0.001 < q < 10$ m³/s)
	Process module	$7.0 \times 10^{-4} + 3.0 \times 10^{-5} q^{-0.6}$	0.02
	Grass-roots plant	$5.0 \times 10^{-4} + 2.5 \times 10^{-5} q^{-0.6}$	0.02
Natural Water, Pumped and Screened[d], \$/m³			($0.001 < q < 10$ m³/s)
	Process module	$1.0 \times 10^{-4} + 3 \times 10^{-6} q^{-0.6}$	0.003
	Grass-roots plant	$7.0 \times 10^{-5} + 2 \times 10^{-6} q^{-0.6}$	0.003
Water Desalination < 500 ppm total dissolved solids (tds) in product. Can be applied to membrane purification of wastewater also			
• Brackish[d] (up to 5,000 ppm tds in feed), \$/m³			($0.04 < q < 1.0$ m³/s)
	Process module	$0.0014 + 4.0 \times 10^{-5} q^{-0.6}$	0.02
	Grass-roots plant	$0.001 + 3.0 \times 10^{-5} q^{-0.6}$	0.02
• Seawater[d] (35,000–40,000 ppm tds in feed), \$/m³			($0.001 < q < 1.0$ m³/s)
	Process module	$0.0015 + 6.0 \times 10^{-5} q^{-0.6}$	0.13
	Grass-roots plant	$0.0012 + 4.5 \times 10^{-5} q^{-0.6}$	0.13
Refrigerant, \$/kJ cooling capacity[e]			($1 < Q_c < 1{,}000$ kJ/s; $0 < T < 300$ K)
	Process module	$0.6\, Q_c^{-0.9}(T^{-3})$	$1.1 \times 10^6 T^{-5}$
	Grass-roots plant	$0.5\, Q_c^{-0.9}(T^{-3})$	$1.1 \times 10^6 T^{-5}$
Hot Water, Hot Oil, or Molten-Salt Heat Transfer Media, \$/kJ heating capacity[f]			($100 < Q_H < 20{,}000$ kJ/s; $350 < T < 850$ K)
	Process module	$7.0 \times 10^{-7} Q_H^{-0.9}(T^{0.5})$	$6.0 \times 10^{-8} T^{0.5}$
	Grass-roots plant	$6.0 \times 10^{-7} Q_H^{-0.9}(T^{0.5})$	$6.0 \times 10^{-8} T^{0.5}$

		Cost coefficients a	Cost coefficients b
Wastewater Treatment[d], \$/m³			($0.01 < q < 10$ m³/s)
• Primary (filtration)			
	Process module	$0.0001 + 2 \times 10^{-7} q^{-1}$	0.002
	Grass-roots plant	$0.00005 + 2 \times 10^{-7} q^{-1}$	0.002
• Secondary (filtration and activated sludge processing)			
	Process module	$0.0007 + 2 \times 10^{-6} q^{-1}$	0.003
	Grass-roots plant	$0.00035 + 2 \times 10^{-6} q^{-1}$	0.003
• Tertiary (filtration, activated sludge, and chemical processing)			($0.0003 < q < 10$ m³/s)
	Process module	$0.001 + 2 \times 10^{-4} q^{-0.6}$	0.1
	Grass-roots plant	$0.0005 + 1 \times 10^{-4} q^{-0.6}$	0.1
Membrane Processes (see water desalination costs above)			
Liquid/Solid Waste Disposal[g], \$/kg			
• Conventional solid or liquid wastes			
	Process module	4.0×10^{-4}	—
	Grass-roots plant	3.0×10^{-4}	—
• Toxic or hazardous solids and liquids			
	Process module	2.5×10^{-3}	—
	Grass-roots plant	2×10^{-3}	—
• Combustion as Supplementary Fuel[h]			($1 < m \times$ HHV $< 1{,}000$ MJ/s)
	Process module	$3.0 \times 10^{-5}\,(\mathrm{HHV})^{0.77}(m^{-0.23})$	-5×10^{-4} (HHV)
	Grass-roots plant	$2.5 \times 10^{-5}\,(\mathrm{HHV})^{0.77}(m^{-0.23})$	-5×10^{-4} (HHV)
• Combustion as Supplementary Fuel (with flue gas cleaning)			
	Process module	$5.0 \times 10^{-5}\,(\mathrm{HHV})^{0.77}(m^{-0.23})$	-4×10^{-4} (HHV)
	Grass-roots plant	$4.0 \times 10^{-5}\,(\mathrm{HHV})^{0.77}(m^{-0.23})$	-4×10^{-4} (HHV)
Gas Emissions Treatment[i], \$/Nm³			($0.05 < q < 50$ Nm³/s)
• Endothermic Flaring			
	Process module	$1 \times 10^{-6} q^{-0.23}$	0.004
	Grass-roots plant	$0.7 \times 10^{-6} q^{-0.23}$	0.004
• Thermal or Catalytic Incineration			
	Process module	$1 \times 10^{-5} q^{-0.23}$	0.002
	Grass-roots plant	$0.7 \times 10^{-5} q^{-0.23}$	0.002
• Thermal or Catalytic Incineration (with flue gas cleaning)			
	Process module	$1.5 \times 10^{-5} q^{-0.23}$	0.003
	Grass-roots plant	$1.1 \times 10^{-5} q^{-0.23}$	0.003
• Combustion as Supplementary Fuel			($1 < q \times$ LHV $< 1{,}000$ MJ/s)
	Process module	$3.0 \times 10^{-5}\,(\mathrm{LHV})^{0.77}(q^{-0.23})$	-6×10^{-4} (LHV)
	Grass-roots plant	$2.5 \times 10^{-5}\,(\mathrm{LHV})^{0.77}(q^{-0.23})$	-6×10^{-4} (LHV)
• Combustion as Supplementary Fuel (with flue gas cleaning)			
	Process module	$5.0 \times 10^{-5}\,(\mathrm{LHV})^{0.77}(q^{-0.23})$	-5×10^{-4} (LHV)
	Grass-roots plant	$4.0 \times 10^{-5}\,(\mathrm{LHV})^{0.77}(q^{-0.23})$	-5×10^{-4} (LHV)

a. $C_{S,f}$, 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 $C_{S,f}$ 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 $C_{S,f}$; m_s is total auxiliary boiler steam capacity (kg/s).

d. q is total water capacity (m³/s).

e. Q_c is total auxiliary cooling capacity (kJ/s), T is absolute temperature (K).

f. Q_H is total auxiliary heating capacity (kJ/s), T is absolute temperature (K).

g. Use these numbers advisedly. Waste disposal costs depend on local public attitude 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/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.

**TABLE 2.
PROPERTIES OF TYPICAL FUELS**

Fuel	Higher (Gross) Heating Value	Density
Bituminous and anthracite coals	27-33 MJ/kg	670-930 kg/m^3(bulk)
Lignite	15-19 MJ/kg	640-860 kg/m^3(bulk)
Wood (bone dry)	19-22 MJ/kg	—
Number 2 fuel oil	38 GJ/m^3	870 kg/m^3
Number 6 (residual) fuel oil	42 GJ/m^3	970 kg/m^3
Gasoline	37 GJ/m^3	700 kg/m^3
Natural gas	38.1-40.7 MJ/Nm^3	0.715 kg/Nm^3

For more detailed information, see Perry [3], Section 27

UTILITY COST ESTIMATION EXAMPLE

Estimate the annual and unit costs of utilities for an alkylate splitter module that consumes 23.5 kW of electricity, 0.10 m^3/s of cooling water, and 3.0 kg/s of 32 barg steam. Assume that the operating or on-line factor is 94% and that electricity is purchased from an outside utility plant that uses No. 6 fuel oil at a price of $4.50/GJ.

Based on a *CE* Plant Cost Index in the range of 460 to 480, the unit price of electricity is

$C_{S,e} = 1.3 \times 10^{-4}(470) + 0.010\ (4.5)$

$= \$0.106/\text{kWh}$

Annual cost of electricity for the alkylate splitter module is given by the power consumption rate multiplied by number of seconds per year, operation factor, price of electricity in dollars per kilowatt hour, and divided by 3,600 seconds per hour:

$A_e = P(31.5 \times 10^6\text{s/yr}) f_o \cdot C_{S,e}(1\ \text{h}/3{,}600\ \text{s})$

$A_e = (23.5\ \text{kW})(31.5 \times 10^6\text{s/yr})(0.94)(\$0.106/\text{kWh})(1\ \text{h}/3{,}600\ \text{s})$

$A_e = \$20{,}500/\text{yr}$

Since this module is part of a large refinery, total plant cooling water consumption is undoubtedly 10 m^3/s or greater. Using that value for q and grass-roots figures from Table 1, the first coefficient a in Equation [1], is calculated as follows:

$a = 0.00007 + (2.5 \times 10^{-5})\ 10^{-1} = 0.000073$

and $C_{S,cw}$ is

$C_{S,cw} = 0.000073\ (470) + 0.003\ (4.5) = \$0.048/m^3$

Annual cooling water cost is calculated as was done for electricity.

$A_e = (0.10 m^3/\text{s})(31.5 \times 10^6\text{s/yr})\ (0.94)(\$0.048/m^3)$

$A_e = \$140{,}000/\text{yr}$

For steam, auxiliary plant capacity is assumed to be the maximum and residual oil at $4.50/GJ is the postulated energy source. From data in Table 1, we can solve:

$C_{S,s\text{-}32} = [(2.3 \times 10^{-5})(40)^{-0.9}(470)] + [(0.0034)(32)^{0.05}]\ (4.50)$

$C_{S,s\text{-}32} = \$0.019/\text{kg}$

and

$A_S = (3.0\text{kg/s})(31.5 \times 10^6\text{s/yr})(0.94)(\$0.019/\text{kg}))$

$A_S = \$1{,}700{,}000/\text{yr}$

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 m^3/s, water will be more expensive per cubic meter than from a plant designed to handle 10 m^3/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 m^3/s and there are no other uses of cooling water on site, you will simply use 0.1 m^3/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 m^3/s, 6 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 m^3/s, that or a lesser value should be used for q, because standard cooling systems are limited to 10 m^3/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 from scratch, offsite capital is included in total project capital. 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 when 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 cost[5] 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 cost of purchased electricity (estimated from Equation [1] with coefficients taken from Table 1) is calculated to be:

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

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 this source 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

3. See Chapter 5 of Reference [2].

4. Even though owned by the same company.

5. In these instances, $C_{S,f}$ in Equation [1] is the price paid for fuel by the electric power plant.

REFRIGERANT AND WASTEWATER TREATMENT EXAMPLE

Calculate the cost of providing 1.2×10^9 kJ/yr of $-5°C$ refrigerant and treating 35,000 m^3 of wastewater per year in a grass-roots biotechnology manufacturing process. The maximum refrigerant demand rate is 40 kJ/s, and maximum plant wastewater flowrate is 0.01 m^3/s. The waste stream contains both organics and inorganic salts, so tertiary treatment is necessary.

Based on Table 1, assuming a *CE* PCI = 470 and $C_{s,f}$ = \$4.50/GJ, the same inflation index and fuel values as in the utility cost estimation illustration on p. 68,

$C_{S,refrig} = [0.5(40)^{-0.9}(268)^{-3}]\,(470) + (1.1 \times 10^6)\,(268)^{-3}\,(4.50) = \$4.0 \times 10^{-6}\ /kJ$

$C_{S,waste\ treat} = [0.0005 + (1 \times 10^{-4})\,(0.01)^{-0.6}]\,(470) + (0.1)\,(4.50) = \$1.43/m^3$

Annual expenses for refrigerant are

$A_{refrig} = (1.2 \times 10^9\ kJ/yr)(\$4.0 \times 10^{-6}/kJ) = \$4{,}800/yr$

And, for wastewater treatment the annual expenses are

$A_{waste\ treat} = (35{,}000 m^3/yr)(\$1.43/m^3) = \$50{,}050/yr$

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. ■

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Authors

Gael D. Ulrich (34R Prentiss St., Cambridge, MA 02140-2241; Email: gael.ulrich@comcast.net) is professor emeritus of chemical engineering at the University of New Hampshire, where he joined the faculty in 1970. He worked at Atomics International Div. of North American aviation and Cabot Corp. prior to entering teaching. He holds a B.S.Ch.E. and an M.S.Ch.E. from the University of Utah and an Sc.D. from the Massachusetts Institute of Technology. For the past thirty years, he has consulted for a number of corporations and presided over a small contract research firm for ten. Material in this article was extracted from Reference [2] published with coauthor P. T. Vasudevan in 2004.

Palligarnai T. Vasudevan is professor of chemical engineering at the University of New Hampshire (Chemical Engineering Department, Kingsbury Hall, Rm W301, 33 College Road, Durham, NH 03824; Phone: 603-862-2298; Email: vasu@unh.edu) where he joined the faculty in 1988. He worked for a large petrochemical company for seven years prior to entering teaching. For the past 15 years, he has worked in the areas of catalysis and biocatalysis. He is currently collaborating with researchers in Spain in the areas of hydrodesulfurization and enzyme catalysis. Vasudevan holds a B.S.Ch.E. from Madras India, a M.S.Ch.E. from SUNY at Buffalo and a Ph.D. in chemical engineering from Clarkson University.