

**Replacement Cost Method
of Valuing
Utility Generation Assets**

Prepared by:

Division of Policy Analysis & Intergovernmental Liaison

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Replacement Cost as the Next Best Option: An Alternative Method to Valuing Utility Generation Assets

There has been much discussion on how to value existing utility generation assets. This topic has arisen in the context of some states moving to either retail or wholesale competition. Many of these states are trying to create an impartial and fair model of competition since the incumbent generation owners often possess a substantial number of competitive advantages. One such advantage the regulated incumbent utilities can possess is owning generating plants that have been depreciated and whose current book values are below the market value of newly constructed units.

To better level the playing field, some states have required divestiture of some or all of the incumbent utility generation assets. Divesting units achieves multiple objectives including mitigating market power of incumbent utilities and promoting more competition and providers in competitive markets. However, one objective of divestiture is to obtain a true market assessment of the value of existing assets such that any shortfalls in payments for that asset that have not been collected from current ratepayers can be measured and provisions made for the utility to be fully compensated. This is referred to as a situation where there are stranded costs. Traditionally, stranded costs occur when the net book regulatory accounting value of the plant is greater than the “fair market” value of the asset if it were sold. The other side of this equation is the situation where the net book value of an asset is less than the fair market value. In this case, the asset has economic value greater than the net book value resulting in stranded benefits.

The only exact method to determine whether assets are either above or below the regulatory, net book value is to require such assets be sold in fair and open markets. However, in some states utilities do not want to divest these units but instead want to separate them into affiliates and make sales either into retail or wholesale markets. Here again, the stranded cost/benefit issue arises since some state commissions want to ensure that any stranded benefits are preserved for the current ratepayers. Conversely, utilities often ask for recovery of stranded costs on the basis that they built the generation assets to serve customers. Regardless of the regulatory position taken, the economic question remains – how does one obtain an accurate assessment of the value of generation assets?

In practice, the regulatory book value of an asset has little to do with its economic value. Economic value is generally based on some kind of discounted present value analysis of the future revenue and profit stream that the asset can produce. This valuation technique is directly applicable to the utility industry where assets are generally long lived and have very high capital costs. A generator that has low production costs with respect to fuel and maintenance has a distinct market advantage if the market price for electricity is higher than its production costs. Likewise, if the capital carrying costs for such a unit is substantially below what a new competitor must finance if they construct a new unit, the incumbent’s advantage is only increased. Such a low cost producer has considerable pricing flexibility in setting its selling price and will tend to set prices at, or slightly below, the next best option. Often unless substantial generation reserves are available, the next best option will be the prices established by newly constructed generators.

This paper looks at asset valuation from a replacement cost perspective by comparing the existing net book value of Florida’s generation fleet to newly constructed plants of a similar type. Second, the paper includes fuel and maintenance costs to estimate the final, overall costs of

producing electricity from existing and new units. Admittedly, this is somewhat of a partial analysis because many variables determine the cost of owning and operating power stations. These include unit size, age of unit, fuel costs, cost of capital, and marketing opportunities. For example, some of the coal fueled powerplants owned by Florida utilities did not have to install expensive environmental controls that newly constructed plants would be required to install today. This analysis also ignores the operating life cycle differences between new and older units. Nonetheless, this approach can offer insight to the magnitude and direction of stranded costs and benefits that might occur in Florida if existing generation were to be separated into affiliate generation companies.

Data Sources

To partially overcome the dissimilar plant and component parts problem, the analysis looks at all plants of similar boiler and fuel types and treated these as sample data points by averaging their costs. Some units had more expensive environmental controls since they were newer units; some were quite old. Ideally, this analysis should be done on a plant-by-plant basis taking into consideration locational impacts and common use facilities. A replacement cost comparison was not done for plants primarily fueled by light or heavy oil. While Florida has a number of such units in its portfolio, these plants are not being constructed in the industry today due to their air emission profiles and the uncertainty of acquiring reasonably priced fuel contracts. The resultant database consists of the complete inventory of nuclear, coal-fired, combined cycle and combustion turbine units of the investor-owned utilities. The units and their generation rated megawatt capacity are listed in Table 1.

Table 1. Existing Powerplant Inventory

Type of Plant	Number of Units	Megawatt Ratings*
Nuclear	5	3993
Coal	28	9281
Combined Cycle	8	3621
Combustion Turbines	103	4440 ⁽¹⁾
Totals	144	21,335

*Summer megawatt ratings.

Powerplants have two factors that affect the final production cost of the electricity that they generate -- production expenses and capital costs. The first set of factors is the actual production costs of the inputs needed to run the plants. This includes fuel and operation and maintenance costs. The second factor is the necessary capital requirements needed to pay for the plant even if it did not operate. Capital requirements would include items like depreciation, return on investment, debt payments, taxes, and insurance.

Data for the actual production costs for the fleet of plants was obtained from the Federal Energy Regulatory Commission (FERC) that requires all jurisdictional electric companies to provide their actual production costs for all plants in the FERC Form 1 reports. All production

costs are actual for the year ending December 1999. To obtain the capital requirements on each plant, staff of the FPSC analyzed the book values of each plant in Florida and calculated the net book value after depreciation and decommissioning costs.¹ For purposes of calculating the capital requirements, a 20% annual carrying charge was applied to the net book value for each plant.² It is important to understand that the allowed rate of return on invested equity set by the FPSC is embedded as one component of this capital carrying charge. Utilities' actual production expenses such as fuel and maintenance does not earn a return, but are passed to customers through cost recovery clauses that are adjusted annually.

The combination of these two input factors leads to an estimate of the all inclusive production and carrying costs of these units. Table 2 shows the comparison of the net book plant value of the existing fleet of plants compared to the likely replacement cost for constructing a similarly fueled plant.

Table 2. Net Book vs. Replacement Costs

Unit Type	Average Net Book Value (\$/kw)	Replacement Costs (\$/kw)	Replacement Unit Mw size
Nuclear	480	3300	>600
Coal	308	1103	250
Combined Cycle	353	512	268
Combustion Turbine	66	472	160

Table 3 compares the all inclusive costs between new and replacement units including production costs and the annual capital costs needed to support the plant. It is important to note that fuel is frequently the largest cost factor in all fossil plants. This is particularly true for plants fueled by natural gas. Traditionally, nuclear and coal fuel costs have been quite stable relative to fossil-based fuels. In terms of dispatch costs, both coal and nuclear have actual production costs in the range of \$15 to \$23 per megawatt hour. The average dispatch costs for existing combined cycle units is around \$25/mWh. Given an average 1999 site delivered natural gas price of \$3.00 per million btu (mmbtu), new combined cycle units are slightly less expensive at \$22/mWh. Given low natural gas prices, new combined cycle units could be competitive with existing generation for some portion of the energy served in Florida if this was the only factor input into their production costs and if natural gas could be obtained for \$3.00 or lower. However, this competitive advantage evaporates when capital costs are included in the analysis or natural gas prices increase. Due to the extremely low cost of Florida's coal and nuclear units, newly constructed natural gas units cannot recover both fixed and production costs when competing for existing baseload energy.

¹*Asset Valuation in a Transitioning Electric Industry.* March 2001. Florida Public Service Commission.

²A capital carrying charge is something of a regulatory construct to act as a proxy for fixed expenses. It is a fixed percentage rate assigned to assets that represents the annual expenses of owning an asset. It includes taxes, return on investment, debt coverage, depreciation and insurance.

Table 3. Total Estimated 1999 Production Costs

Existing Units	Production Costs (\$/mWh)⁽¹⁾	Capital Costs (\$/mWh)⁽²⁾	Total Costs (\$/mWh)
Nuclear	15.54	14.61	30.15
Coal	22.83	9.37	32.30
Combined Cycle	25.03	10.74	35.77
New Units⁽³⁾			
Nuclear	25.78 ⁽⁴⁾	100.07	125.80
Coal	23.99 ⁽⁵⁾	33.45	57.44
Combined Cycle	22.00 ⁽⁶⁾	15.52	37.52

(1) Includes 1999 fuel and maintenance costs from FERC Form 1.

(2) Used 20% annual carrying charge rate applied to the net book value and replacement costs. It is possible that due to higher debt to equity ratios, privately financed projects could have a slightly lower cost of capital, but it would be immaterial to the overall cost structure. Used a 75% capacity factor to allocate revenue requirements for all units.

(3) Used overnight capital construction costs including indirect costs from Black and Veatch, Docket 001713-EM as shown in Table 2.

(4) Based on 1999 actual costs and \$14.40/mWh fixed cost taken from Black and Veatch.

(5) Based on 1999 actual costs of \$19.94 and \$4.05/mWh fixed costs taken from Black and Veatch.

(6) Based on \$3.00 mmbtu delivered gas and a 7200 btu/kWh heat rate. Includes \$.39/mWh fixed costs taken from Black and Veatch.

Customer Cost Impact

Table 3 also offers some insight as to how to proceed to value these generation assets. Under existing regulation, the FPSC sets rates to retail customers based on actual production costs. The FERC similarly sets cost-based rates for those utilities deemed to have market power. However, if and when competitive markets prevail and utilities are permitted to seek market-based rate authority, prices will move toward equilibrium clearing levels. In this case, since the next best competitive option to coal and nuclear production appears to be new combined cycle generation, the production costs for combined cycle can be viewed as an index of what these equilibrium or market clearing prices might be.

Using the data for 1999 and assuming that rates were allowed to increase for base load energy, one can estimate the potential increase in costs to consumers. *Again, this analysis assumes that no regulatory restrictions are imposed on the ability of existing generators to raise rates to market clearing levels based on \$3.00 natural gas.* For 1999, the four investor-owned utilities in Florida produced some 30,289 gigawatt hours (1 gigawatt hour = 1000 megawatt hours) of electricity from nuclear units and some 48,885 gigawatt hours from coal units. The weighted average production cost for this 79,174 gigawatt hours of energy including capital costs was \$31.47 per megawatt hour (or about 3.2 cents per kWh). The difference between embedded costs of \$31.47 and the next best option of replacement energy from combined cycle of \$37.52/mWh or \$6.05/mWh represents the potential increase in rates. Multiplying this figure by the total sales of 79,174 gigawatt hours represents a first year cost increase to customers of **\$479 million**. This is a

single year estimate. The next step in the analysis would require projecting how many years this differential exists – all variables held constant – and present valuing this difference stream back to the current year.

It is important to note that this \$479 million cost increase should be offset by reductions in production costs for older, higher cost, less efficient units in the existing fleet. Introduction of new combined cycle units would cause some of these units not to be dispatched. However, the incumbent utilities already possess some 3700 megawatts of combined cycle units with similar production costs and are rapidly building new units. By allowing new, competitive merchants into the dispatch, one is only accelerating the phase-out of plants that would normally be retired or excluded from the dispatch curve for economic reasons. However, at this time, it does not appear that the number of production hours for the inefficient units would offset the increased rates imposed on customers from baseload nuclear and coal units as their prices move toward market clearing levels.

Higher Priced Natural Gas Cases

The base case analysis assumes that the next best option for determining replacement baseload energy prices is the production costs associated with combined cycle power plants fueled with \$3.00 mmbtu natural gas. During the winter of 2000 and the first part of 2001, natural gas prices have been as high as \$9.00 mmbtu at the Henry Hub delivery point in Louisiana. This figure does not include transportation to Florida powerplants. Currently, front month delivery of natural gas on the New York Mercantile Exchange is around \$5.25 per mmbtu. With an additional \$.75 for transportation, delivered natural gas to plant sites in Florida will average around \$6.00 mmbtu.

It is likely that the market value of low cost producing nuclear and coal assets will increase if natural gas prices move higher because coal and nuclear fuel is relatively insensitive to changes in natural gas prices and the difference between actual production costs and the combined cycle option increases and thus the revenue stream is greater. To explore what the potential increased profits for incumbent generators might be given that no regulatory constraints prevent generation affiliates from moving to market clearing prices, Table 4 shows the overall production costs for new plants assuming various price levels of natural gas.

Table 4. Higher Natural Gas Scenarios

Delivered Gas Costs (\$/mmbtu)	All Inclusive Production Costs (\$/mWh)	Differences in Base Case Nuclear and Coal Costs (\$/mWh)*	Potential Increase to Customers (billions)
\$4.00	\$44.79	\$13.32	\$1.054
\$5.00	51.90	20.43	1.617
\$6.00	59.11	27.64	2.188

*For simplicity it is assumed there are no cross price elasticities between coal, nuclear and natural gas. In reality, nuclear is rather insensitive to alternative fuel costs. There is probably a small impact on coal prices as natural gas prices increase, but would not materially alter these results.

Given the assumptions contained herein, Table 4 shows that a single-year cost impact on

customers ranges between \$1 and \$2.1 billion. Again, this is a single-year impact and the true impact will be a multiple of this value going forward into time approximately discounted back to current years worth.

Conclusion

This paper is not meant to be the final word on stranded costs/benefits. It is simply one method to begin to assess their magnitude and direction. It is a static, one-year analysis based on cost differentials. The work concludes that incumbent utilities have substantial market advantages with respect to generation if permitted to separate these assets into unregulated affiliates who could escape cost-based rates. These advantages could be reflected in higher costs to customers and higher returns to shareholders. These advantages include lower fuel costs, lower net book values, and some other advantages not included in this analysis. For example, many existing generators are located in high load areas and the electric output of these units may avoid line losses during transmission and avoid transmission costs to move power to load centers. Similarly, new entrants may be disadvantaged since they may have to incur additional transmission costs depending on their location. Such location impacts are not reflected in the production costs above.

As mentioned earlier, it is the discounted revenue and profit produced by an asset that is the final arbitrator of value. This static analysis should be extended by performing a multi-year economic dispatch model for Florida under various natural gas price scenarios. The difference between cost-based production and market clearing prices could be estimated given the current load and energy projections. By present valuing the difference between production and clearing prices and adjusting for the required after tax return on capital, one could begin to assign a specific market value to these units. In addition to estimating the stranded value, this type of dynamic study would provide more reliable estimates of both production costs and the likely shift in costs to customers.

Finally, a dynamic dispatch study could quantify savings for electric production costs due to the earlier introduction of combined cycles brought into service by new entrants. Such savings should be offset against the costs identified in this paper to produce a more accurate assessment of the change in Florida's electric costs.