Comments on TVA Cost of Service Analysis[1]

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This commentary is based on review of the Tennessee Valley Authority's *Cost of Service Fiscal Year 2016: A Summary of Wholesale Cost of Service Methodologies and Results*, presented in May 2017, TVA's 2018 Wholesale Rate Change: Draft Environmental Assessment dated March 2018 and select additional public documents and presentations prepared by TVA. These comments are intended to identify the main topics regarding TVA's cost of service methods and approach to rate design that are important for TVA and the local power companies ("LPCs") to reconsider.

For purposes of wholesale cost of service analysis, TVA uses standard accounts as specified by the Federal Energy Regulatory Commission and groups these into five "functions": capacity, energy, transmission, other, and taxes. As I discuss at greater length below, the group of accounts that TVA summarizes as "capacity" should properly be labeled as "plant" and the group of accounts labeled as "energy" should be labeled as "fuel and net purchased power". Otherwise, this grouping of accounts is reasonably consistent with industry practice. TVA's functionalization of "plant" as "capacity" and "fuel and purchased power" as energy is not conceptually sound.

Fixed and Sunk Costs

TVA's cost of service analyses are founded in an incorrect idea that then infects much of their analysis. TVA claims that "[c]osts fall into two broad categories: fixed and variable." And further elaborates that "Generation costs are classified as capacity or energy. Capacity costs are costs incurred to generate electricity that do not vary with generation, and are considered fixed. Energy costs are costs incurred to generate electricity that vary with generation and are considered variable."

TVA has clearly conflated and confused fixed costs and sunk costs.

The carrying cost of a power plant (deprecation, cost of capital, fixed maintenance, etc.) do not vary with generation in the short term but do vary with generation in the long-term. Power plants are built in anticipation of generation requirements. Once built, the costs of a power plant are **sunk** in that they cannot be avoided by not running the plant but that does not make them **fixed**.

Given that the number of power plants owned by TVA and their sizes reflect accumulated decisions by TVA about how much generation is needed to serve its customers, it should be clear that none of the cost of power plants is **fixed.**

Plant vs Capacity

TVA claims that "Generation costs are classified as capacity or energy. Capacity costs are costs incurred to generate electricity that do not vary with generation, and are considered fixed. Energy costs are costs incurred to generate electricity that vary with generation and are considered variable." This assertion conflates and confuses plant costs with capacity costs. The FERC accounts that TVA functionalizes as

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capacity are in fact **plant** costs and FERC clearly labels these accounts as **plant** costs. This error reflects the confusion of fixed and sunk costs discussed above.

Conflating plant costs with capacity costs then leads TVA to allocate plant costs in total to customer classes and to LPCs based on a measure of system peak demand. TVA provides some discussion and analysis of different ways to measure and allocate responsibility for capacity but none of these overcome the original sin of calling **plant** costs **capacity** costs.

The simple way to see the defect in conflating **plant** and **capacity** costs is to think about the various types of plants in TVAs fleet. Allocating plant costs based on class contribution to system peaks means that the vast majority of the cost of nuclear plants is allocated to peak demand, most of the cost of coal plants is allocated to peak demand, and presumably any TVA owned wind and solar plants would be allocated to peak demand. Most utilities would also allocate virtually all costs of hydropower facilities to plant; to the extent that TVA allocates costs of dams and related facilities to hydropower these also appear to be counted as capacity costs and allocated to peak demand.

But, if the only reason to build a power plant was capacity at peak times, TVA would build a natural gas combustion turbine because the carrying cost per unit capacity of a combustion turbine plant is much cheaper than the carrying cost per unit capacity of a hydropower plant, nuclear plant, coal plant, wind plant, or solar plant. The only reason for TVA to have built hydropower, nuclear, or coal plants instead of combustion turbines (or the predecessor reciprocating engines) is to produce energy. It is therefore inappropriate to allocate the carrying costs of hydropower, nuclear, coal, solar, or wind plants based on peak demand. That misallocation is the direct result of conflating **plant** costs with **capacity** costs.

A correct cost of service analysis would split **plant** carrying costs into an allocation to **capacity** costs and an allocation to energy costs. Utility regulators use a variety of practices to split plant carrying costs into an allocation to capacity costs and an allocation to energy costs, but the most theoretically sound is to allocate to capacity the carrying cost of a combustion turbine times the peak-time capacity of each plant and to allocate the remaining carrying cost of the plant to energy. TVA has simply relabeled plant costs as capacity costs rather than providing a fair and careful functionalization of **plant** costs to **capacity** and **energy**.

Based on review of TVA's Integrated Resource Plan, 2015 Final Report, TVA implicitly uses this distinction between plant and capacity in its Integrated Resource Planning. The Integrated Resource Plan clearly discussed capacity as the maximum output from plants and capacity requirements as the total capacity required to meet peak demand with a reserve margin. It also discusses energy as the output of plants delivered over time. The software used by TVA in its least-cost planning clearly performs mathematical optimization of a generation portfolio in a way that would choose a combustion turbine if capacity is only needed to meet peak load and reserve margin and uses other plants based on their ability to produce energy over the year at a variable cost that is enough less than the variable cost of operating a combustion turbine to justify the extra investment in plant of some type different than a combustion turbine. Putting it less mathematically, the extra carrying cost of a plant other than a combustion turbine is justified by its ability to produce energy more cheaply than a combustion turbine will.

TVA also recognizes this distinction between plant and capacity in its consideration of interruptible rates. For example, in the TVIC Pricing Committee Strategic Pricing Plan Presentation of September

2014, slides 15-23 discuss the pricing of interruptible service by assessing its value relative to the economic carrying charge of a combustion turbine. Because interruptibility only provides capacity at peak times it would be inappropriate to credit it with the full embedded cost of plant per unit capacity; TVA is correct in that analysis, but the point applies to all capacity.

Sometimes, capacity costs are based on the cost per unit capacity of new entry of a combustion turbine, which is the economic carrying cost of a new combustion turbine in its first year. The argument for this is that this is the marginal cost of capacity in an environment of growing peak demand. However, it can be argued that over a longer period, marginal demand only needs to cover the life-cycle cost of new capacity; this is more clearly true in an environment without systematic demand growth. Thus, the cost of service study should use the levelized carrying cost of a combustion turbine as the appropriate measure of carrying cost.

Energy vs Fuel and Purchased Power

TVA claims that "Generation costs are classified as capacity or energy. … Energy costs are costs incurred to generate electricity that vary with generation and are considered variable." This claim reflects the same point of confusion as TVA's conflation of **plant** and **capacity**. **Energy** is not another word to summarize **fuel and net purchased power.** Rather, the word **energy** should be used to functionalize both these variable costs and the portion of plant costs that are incurred to energize the grid throughout the year. It is simply not the case that all plant costs are incurred to meet peak demand and are "free" for generation the rest of the year. TVA has simply relabeled fuel and net purchased power costs as energy costs rather than providing a fair and careful functionalization of **plant** costs to **capacity** and **energy**.

As discussed above, the cost of service study should functionalize a portion of plant costs to energy by assigning the carrying cost of a combustion turbine times the capacity of each generation asset to **capacity** and assigning the remainder of the embedded cost of the plant to **energy**.

TVA's Wholesale Cost of Service Allocators

Having functionalized direct costs as capacity, energy, transmission, other and taxes, TVA allocates these costs to customer classes in fairly conventional ways.

TVA allocates capacity costs based on the top 200 hours. This is an appropriate method and is superior to the narrower allocation basis recommended by TVIC. If TVA were to actually price capacity costs to demand during peak hours based on a small number of hours, customer response to the resulting very high prices would lower demand during those peak hours to a level lower than at other hours not currently in the peak demand period. 200 hours is a more reasonable approximation of the customer responsibility for capacity costs that would result from actually pricing capacity during peak hours and is therefore economically more efficient than a narrower basis for cost allocation.

TVA allocates fuel and net purchased power costs (which they have unreasonably labelled as energy costs) by using hourly average fuel and net purchased power cost and assigning these costs to customer classes based on customer-class load shares of each hour. This practice would be appropriate for the allocation of energy costs, and marginal cost of energy would be even better, if plant costs were functionalized to capacity and energy as I discussed above. Unfortunately, TVA's current practice double-charges certain costs to residential customers. Average fuel and net purchased power costs are higher when load is higher because that is when the plants with higher fuel costs are operated. Low fuel cost per unit energy when load is lower is accomplished by investing in more expensive plant that generates with a lower fuel cost. But, residential customers contribute a greater share of capacity than energy and therefore pay a disproportionate share of the cost of “baseload” power plants which provide energy at lower variable cost during the times when residential load is low. Consequently, TVA’s current practice causes residential customers to pay for plant costs whose only justification is to reduce the costs of providing “baseload” power to non-residential customers.

TVA allocates transmission costs based on the 12CP method, meaning that transmission costs are allocated evenly to the 12 months, then allocated to customer classes based on their share of the peak hour of each month. This method is prescribed by FERC for FERC-regulated transmission tariffs and should be considered standard practice.

TVA generally allocates all other costs and taxes as “overhead” on capacity, energy, and transmission costs. This is appropriate and conventional, though there is one notable concern. TVA has previously included interest on regulatory assets under the heading of “Other Costs”. Regulatory assets should generally be functionalized like the rest of rate base.

TVA’s Treatment of Bellefonte Interest

Slide 57 of TVA’s September 2014 presentation to the TVIC Pricing Committee indicates a past practice of allocating interest on regulatory assets related to the Bellefonte plant as “Other Costs”, which then allocated as overhead to directly functionalized cost of capacity, energy, and transmission. That same slide indicates intent to functionalize regulatory assets of the Bellefonte plant similarly to TVA’s treatment of other ratebase; this is more appropriate than treating it as “Other Costs”. However, TVA’s proposed functionalization to Capacity and Transmission is likely inappropriate because a portion of these costs should be allocated to Energy as discussed earlier in this commentary.

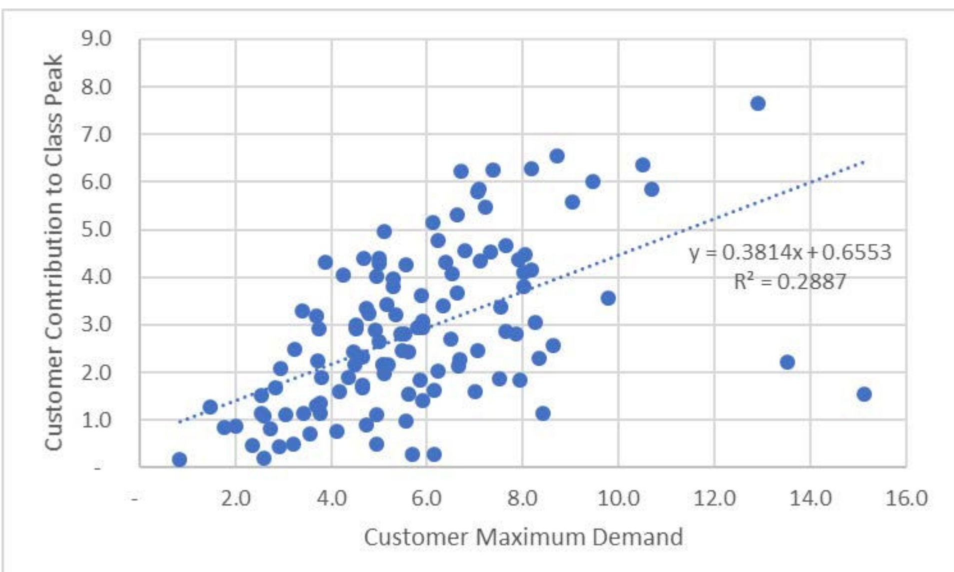
TVA’s Approach to Rate Design

In establishing rates to its direct customers and to LPCs, TVA emphasizes demand charges for recovery of plant costs. Much of TVA’s discussion about this focusses on “load factor”, which is the ratio of average power demand to the individual customer’s peak demand. Consideration of “load factor” is faulty reasoning for rate design related to generation plant because what determines a customer’s contribution to plant costs is the customer’s demand coincident with the system peak demand that drives capacity requirements. Individual customer peak demand is generally not coincident with system peak demand and often is not a very good predictor of the customer’s contribution to coincident peak demand. For example, a processor of agricultural commodities will likely experience it’s peak demand in the fall and will have a relatively low load factor while imposing little demand at the system peak. Significantly more accurate cost allocation and price signals are provided by using either time-of-use rates or critical peak pricing rather than customer demand charges to recover capacity costs. TVA should not allocate any generation capacity cost based on maximum demand and should allocate all such costs to either on-peak energy or on-peak demand. Statistical analysis of individual customer data is likely to show that on-peak energy is a more accurate predictor of customer contribution to the capacity allocator (top 200 hours) than is on-peak demand in which case on-peak energy would be the more appropriate billing determinant in the rate design.

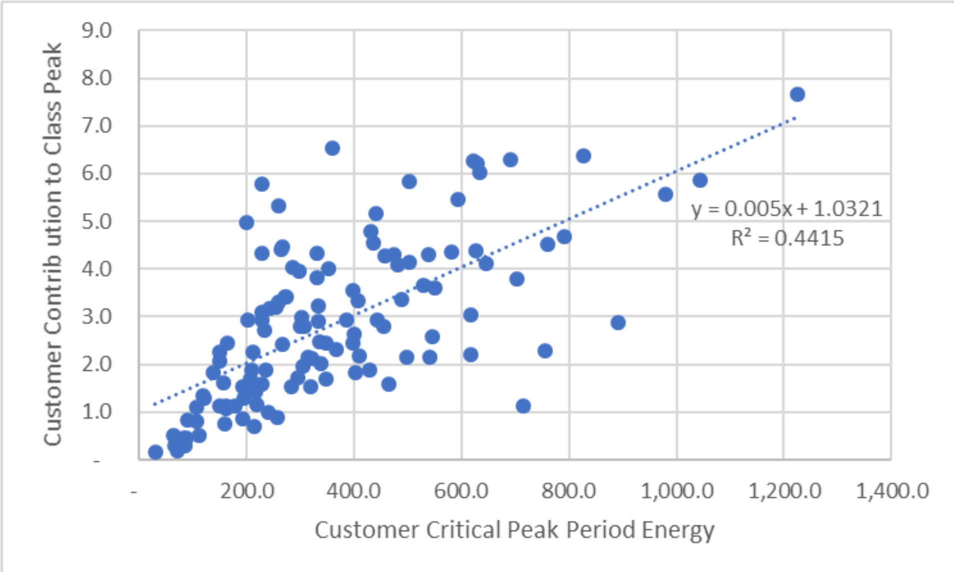
TVA's expectations about how LPCs will design their rates suffers from the same inappropriate use of demand charges. In particular, TVA proposes to change a portion of the energy charge into a "grid access charge" and then move toward recovery of the grid access charge through some combination of "a declining block rate structure, introduction of a demand charge where one did not previously exist, hours use of demand structure, and a demand ratchet on distribution delivery charges." TVA's stated motivation for this proposal is "to better align wholesale rates with their underlying costs to serve and to facilitate measured, managed change for retail customers". However, TVA has not produced any evidence that these rate design proposals accomplish this purpose. To do so, TVA would need to show that the proposed rate design is a better predictor of each customer's contribution to cost of service than is the current rate design. Indeed, TVA ought to demonstrate through a statistical analysis that a proposed rate design is the best practicable predictor of each customer's contribution to cost of service. TVA has not offered any such evidence.

As an example of the kind of analysis that TVA should undertake, the following graphs illustrate the relationship between individual customer maximum demand and their contribution to class peak in comparison to the relationship between individual customer critical peak period energy and their contribution to class peak. Class peak is often used in cost of service studies to allocate a portion of the costs of distribution systems.

These graphs present data from a random sample of residential customers of a midwestern utility in which distribution system peak occurs late on a summer afternoon and critical peak energy is the total kWh delivered between the hours of 2 and 5pm during the months of June through September. The first graph shows the relationship between customer contribution to class peak and customer annual maximum demand.



The second graph shows the relationship between customer contribution to class peak and customer critical peak energy.



The statistic R^2 is sometimes interpreted as describing the percentage of variation in the dependent variable that is explained by the independent variable. In this case, customer demand explains 28.87% of customer contribution to class peak while critical peak period energy explains 44.15% of customer contribution to class peak. Critical peak period energy is clearly a better billing determinant for recovery of distribution system costs that is customer maximum demand.

Absent such analysis, TVA's approach to rate design should be considered arbitrary. TVA is likely to assign costs to customers in a random manner with respect to what it truly costs to serve the customer.