

PEAK CREDIT METHODOLOGY

The Peak Credit Methodology uses the ratio a simple cycle turbine unit costs to a combined combustion turbine for an energy/demand ratio. The method of calculating the cost of these resources has varied from case to case but generally includes the capital, fixed, and fuel costs for some number of operating hours throughout a calendar year.

History

In the 78' Generic Case, the Commission evaluated and responded to the Public Utility Regulatory Policies Act. The Commission determined that the use of embedded cost as a basis for cost allocation would be properly constructed if it was “forward looking...reflecting the purposes for which plant expenditures are being made”.¹ The embedded costs served as a clear starting point that did not require estimates. In 1981 (U-81-10), the Commission approved for Washington Water Power a modified version of the “Equivalent Peaker Method” called the Peak Credit Methodology. The Peak Credit Methodology answered the Commission’s call for a “forward-looking” dimension in cost of service studies. It was quickly adopted for both Puget Sound Energy (U-82-38) and Pacific Power & Light (U 81-17).

Following a Rate Design Collaborative involving numerous parties, PSE presented in its 1992 GRC (UE-920499), a modified Peak Credit Methodology. The 1992 Peak Credit Methodology was broken down as follows:

- A. Peak Credit Calculation results in 13% Demand/87% Energy using:
1. One-half the fixed costs and O&M associated with a Combustion Turbine
 2. Fuel cost inputs based on Natural Gas
 3. An 80% capacity factor.

$$Demand = \frac{\frac{1}{2}(CT\ Fixed+O\&M) / kW_{CT}}{(CCT\ Fixed+O\&M)*80\% / kW_{CCT}} \qquad Energy = 1 - Demand$$

The 1992 modified Peak Credit Methodology serves as the starting point for each of the three electric IOU’s.

PACIFIC POWER

2013 Pacific GRC (UE-130043)	Pacific Power abandons Peak Credit methodology in favor of Peak & Average
2010 Pacific GRC (UE-100749)	<i>Commission Order</i> o Simple Cycle Combustion Turbine (peaking resource) replaced with capacity costs from firm capacity sales agreement with BPA.

¹ UE-82-10, Second Supplemental Order at page 36

Pacific Power no longer uses the peak credit methodology, although the Commission has ordered a return to it absent a “clear showing” of the need for a new method. In 2010 Pacific was unopposed in using a firm capacity sales agreement from BPA for capacity costs. Pacific Power asserted, and the Commission agreed, that since Pacific does not operate a simple cycle combustion turbine in the western balancing authority, cost allocation should be based on the resource that is used for peaking needs.²

PSE

2009 PSE GRC (UE-090704)	<p><i>Multi Party Settlement – No changes to cost of service</i></p> <ul style="list-style-type: none"> ○ PSE Proposals are not adopted: <ul style="list-style-type: none"> ● Peak credit calculation includes emissions costs ● Eliminate fuel and variable O&M costs ● Apply reserve requirement to baseload resource.
2006 PSE GRC (UE-060266)	<p><i>Multiparty settlement</i></p> <ul style="list-style-type: none"> ○ Peak credit calculation assumes operation of 75 hours with natural gas using peak fuel prices. Includes 100 percent of O&M related to peaking resource.
1992 PSE GRC (UE-920499/UE-921262)	<p><i>Commission Order</i></p> <ul style="list-style-type: none"> ○ Use 50% of fixed cost for Peaker resource with 80 percent capacity factor ○ Use natural gas as fuel costs for Peaker resource ○ Assume operation of 200 hours.

At the start, the PSE proposed Peak Credit Methodology assumed 200 operating hours and that diesel would be used for fuel. The method utilized only 50 percent of the fixed costs for the peak resource, under the belief a CT would firm hydro resources as well as respond to peak. The proposed methodology assumed an 80 percent capacity factor based in line with the Company’s avoided cost calculation. Various modifications have been incorporated into the method since its inception.

² UE-110479, Final Order 06 at ¶303

AVISTA

2011 AVISTA GRC (UE-110876)	<p><i>Multi Party Settlement – No changes to cost of service</i></p> <ul style="list-style-type: none"> ○ Avista Proposals are not adopted: <ul style="list-style-type: none"> ● System load factor to determine demand portion of production costs.
2010 AVISTA GRC (UE-100467)	<p><i>Multi Party Settlement – No changes to cost of service</i></p> <p>Avista utilizes IRP based analysis of total dispatch value from a CCCT to determine demand/energy ratio</p>
1999 AVISTA GRC (UE-991606)	<p><i>Commission Order</i></p> <p>Accepts modified Peak Credit Methodology because “...the peak usage patterns of each unique company are appropriately used in that company’s cost of service study.”³</p>

Avista first adopted the peak credit methodology in its 1999 GRC. Avista’s proposal was unique as it was segregated by plant type. The Avista method compared the replacement cost per kW for a peaking simple cycle combustion turbine to the replacement costs for a thermal and hydro plant separately.

In 2010, Avista proposed an alternative to the Avista specific peak credit methodology citing concerns over the efficiency and accuracy of individual demand and energy contributions for each FERC account.⁴ To solve this problem, Avista proposed to use IRP calculated 20-year market dispatched value of a CCCT as the total value of energy for the plant. The ratio of the costs not recovered through the energy sales of the CCCT to the total cost of the CCCT represents the demand component. The 2010 case settled and did not discuss the proposed methodology.

The proposal also proved to be short-lived. After a 2010 general rate case in Idaho, Avista and stakeholders evaluated the proposed IRP methodology. The workshop questioned the long-term stability of the methodology as well as how an analysis of costs relationships based entirely on projected values could be in an embedded cost study.⁵ In general, they found it to be “complicated to compute and apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and forth between energy and demand.”⁶ Based on this finding, Avista proposed to use a long run incremental capacity resource costs analysis from the IRP.

Avista proposed in 2011 to use a system load factor rather than the IRP analysis. The system load factor presented a more direct way of allocating production costs between demand and energy.

³ UE-991606, Third Supplemental Order at ¶408

⁴ Kalich, UE-100467, CGK-1T 26:14-28:6

⁵ Knox, UE-110876, TLK-1T 14:13-16

⁶ Knox, UE-120436, TLK-1T 15:20-22