Lifetime cost analysis for Energize Eastside

What will Energize Eastside cost customers over its lifetime?

February 17, 2016

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CENSE engaged Jeffrey King, a utility financing expert, to give us better answers to this question. Mr. King worked as a Senior Resource Analyst for the Northwest Power Planning Council for nearly 30 years.

Mr. King used MicroFin modeling software to come up with three different lifetime scenarios (45, 55, and 65 years) using a project base cost of $100 million. The details of his analysis can be found in the following pages of this document.

A base cost of $100 million is considerably less than PSE's cost estimates, but the results of the model can simply be scaled by the ratio of the actual cost to the base cost. For example, if the cost were to be $300 million (three times the base cost), the results from Mr. King's analysis could simply be multiplied by a factor of 3.

PSE has not updated cost estimates for Energize Eastside, and the EIS contains no reference to the project's cost. Our best guess is that it will cost at least $250 million. We scaled the results of Mr. King's analysis by a factor of 2.5 to arrive at the following lifetime costs:

Lifetime of Energize Eastside *transmission line*	*Total cost to ratepayers*
45 years	$1.45 billion
55 years	$1.74 billion
65 years	$2.03 billion

If those numbers seem large, it's mostly because state policy guarantees PSE a return on investment of 9.8% per year for infrastructure projects. Interest adds up quickly at that rate.

Revenue collected by PSE for this level of investment would be approximately $32 million per year. This is an important number, because it is possible to buy quite a bit of technology to implement alternative solutions with expenditures of that size. Because alternative solutions can be built incrementally as the need arises, we probably wouldn't need to continue that level of investment for 45-65 years.

We see an opportunity to build a solution of just the size we need and save a lot of money for ourselves, our children, and our grandchildren.

Estimation of the fixed charge rate and revenue requirements for the proposed Energize Eastside transmission project

Prepared for CENSE.org by Jeffrey C. King & Associates
February 10, 2016

The Energize Eastside transmission project is intended to reinforce the Puget Sound Energy electrical distribution system on the east side of Lake Washington in King County, Washington, an area that has experienced significant growth over the past several decades without concurrent expansion of the local transmission system. The Energize Eastside project is proposed to be an overhead single-circuit 230 kV transmission line[1] extending from the existing Talbot Hill substation in Renton approximately 18 miles north and east to the existing Sammamish substation in Redmond, passing through Bellevue, Kirkland and other Eastside communities. The line would feed, from both ends, a new or expanded substation in the Bellevue vicinity. Preconstruction fieldwork commenced in January 2015 and construction is proposed to commence in the second quarter of 2017 for fourth quarter 2018 energization.

The purpose of the work described in this paper is to estimate the levelized fixed charge rate (FCR)[2] and revenue requirement[3] of the proposed Energize Eastside project. Revenue requirement can subsequently be used to estimate the rate impact of the proposed project.

The MicroFin Levelized Project Revenue Requirements model, developed by the Bonneville Power Administration and the Northwest Power and Conservation Council is used to calculate project FCRs and revenue requirements. MicroFin uses normalization accounting[4] to simulate investor-owned utility financing of electric power projects. MicroFin calculates total project investment costs using a construction cost estimate, construction cash flows and financing information. Annual cash flows over the forecast service life of the project are then calculated. Components of annual cash flows for transmission projects include debt service, debt interest, return on equity, equity recovery, income and property taxes, insurance, operation and maintenance expenses, interim capital replacement costs and the cost of losses. The net

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[1] *The project may use towers capable of carrying a future second 230KV line.*

[2] *The Fixed Charge Rate is the levelized annual cost of financing the construction of a project over the economic life of the project, expressed as a percentage of total investment cost. The total investment cost is the cost of developing and constructing a project (capital cost), including price escalation and interest incurred during the construction period.*

[3] *Project Revenue Requirements are the annual costs of constructing and operating a project. Revenue requirements consist of the annual financing costs (Fixed Charge Rate x Total Investment Cost) plus annual operation and maintenance costs (expensed and capitalized).*

[4] *Normalization accounting shifts a portion of the benefit of accelerated tax depreciation to later years of the life of a project. Normalization accounting is mandated by the Internal Revenue Service for investor-owned utilities.*

of these comprise annual revenue requirements. Annual revenue requirements may vary over the life of a project due to factors such as cost escalation and a service life that exceeds the financing life. A levelized revenue requirement (an equivalent constant value) is then calculated by taking the net present value of the series of annual revenue requirements, then calculating a constant series of annual payments with equivalent net present value.

For calculating the FCR and revenue requirements of a transmission project, MicroFin requires information regarding project capital costs, operation and maintenance (O&M) costs, interim capital replacement costs; construction cash flows; the project owner's financial structure, tax obligations and incentives, if any; forecast general inflation and escalation rates of capital and O&M costs; and electrical losses. Other MicroFin input data such as fuel cost and emission costs are not applicable to a transmission project. The information needed by MicroFin to calculate a fixed charge rate and revenue requirement for a transmission project is shown in Table 1 with the known or assumed values for the Energize Eastside project and sources of this information. Additional information regarding the derivation of certain input assumptions is provided in the Appendix.

Capital costs for transmission projects vary widely and the capital cost estimates for the proposed Energize Eastside project were not available for this analysis. $100 million is used as a placeholder. $100 million is substantially greater than typical cost for a 230kV project of this size, however the congested nature and environment of the proposed corridor will likely increase construction cost well above typical costs. Once construction cost estimates are available, revenue requirements can be calculated by taking ratios of $100 million. Because all cost input assumptions for this project are a constant percentage of the capital cost and all input costs are independent of the load factor of the line, the relationship of overnight capital to revenue requirements is linear.

An uncertainty of some importance is the assumed service life of the project. PSE estimates that the service life of transmission facilities will range from 45 to 65 years. For this reason, FCR and revenue requirements calculations were run for 45, 55 and 65 year service lives.

The estimated fixed charge rates and levelized annual revenue requirements for a $100 million overnight capital cost investment in a project with the characteristics of the proposed Energize Eastside project are shown in ***Table 2*** for 45, 55 and 65 year service lives. Also shown is the AFUDC ratio, to calculate total plant investment *(basis of the fixed charge rate)* from the overnight construction cost. All values are "nominal", e.g., include the effects of forecast general inflation, and therefore represent the actual dollar impact on rates.

Table 1: Modeling input data values and sources

Input	Value	Source	Note
Plant Data:			
Start of construction	1/1/2017	Approximation of PSE Q2 2017	Closest MicroFin time series increment.
Service date	1/1/2019	Approximation of PSE end of Q3 2018	Closest MicroFin time series increment
Service life	44, 55 and 65 years	PSE 2014 FERC Form 1 page 123.14	
Overnight capital cost	100 million	Placeholder	
Annual construction cash flow	50%/yr	JCK assumption	
Capital cost real escalation	Zero	JCK assumption	Reflects currently low rates of labor and equipment price escalation.
Annual operation and maintenance expenses	1.3% of overnight capital cost	See Appendix	Exclusive of property tax and insurance.
O&M cost real escalation	Zero	JCK assumption	Reflects currently low rates of labor and equipment price escalation.
Generation integration costs	n/a		No significant generation would be interconnected to the proposed project.
Control and dispatch costs	Zero		Project is assumed not to significantly affect the control and dispatch costs of the PSE system
Cost of losses	Zero		Project will likely reduce system losses overall but extent not known w/o load-flow analysis
Interim capital replacement	1.2% of overnight capital cost	See Appendix	Levelized annual cost of replacing major equipment over the life of the project.
Input price year dollars	2016		Cost estimates are assumed current
Project financing			
Debt term	30 years	JCK assumption	
Equity recovery period	30 years	JCK assumption	
Debt/Equity ratio	52/48	PSE 2014 FERC Form 1, page 109.2	WUTC approved, effective 1/2014
Debt interest rate (nominal)	5.75%	See Appendix	Average of recent PSE 30-year issues plus 0.25% for Dec 2015 Federal Reserve increase.
Return on equity (nominal)	9.8%	PSE 2014 FERC Form 1, page 109.2	WUTC approved, effective 1/2014
Debt financing fee	1.0% of issue	See Appendix	Average of recent PSE 30-year issues.
Discount rate (nominal)	6.7%	Calculated	After-tax cost of capital for the assumed financial parameters (PSE perspective)
General inflation rate	See Appendix	NPCC 7th Plan (draft)	
Taxes and Insurance			
Federal income tax rate	35%	PSE 2014 FERC Form1	
FIT recovery period	20 years	IRS Pub 946	Recovery period for transmission assets
Federal investment tax credit	None		
State income tax rate	None		
State investment tax credit	None		
Annual property tax rate	0.95% of overnight capital cost	See Appendix	Average King Co. property tax rate x ratio of assessed to true value for King Co.
Annual property insurance rate	0.06% of overnight capital cost	See Appendix	Average PSE property insurance cost on electric plant property

Table 2: Estimated AFUDC ratio, fixed charge rates and revenue requirements *(Nominal values)*

Case	AFUDC Ratio	Annual FCR (% Total Plant Investment)	Annual Revenue Requirement ($/yr)
$100 MM overnight cost; 45-year useful life	1.038	9.9%	$12,869,000
$100 MM overnight cost; 55-year useful life	1.038	9.7%	$12,622,000
$100 MM overnight cost; 65-year useful life	1.038	9.6%	$12,505,000

Appendix: Derivation of certain modeling input assumptions

Operation and maintenance costs: Operation and maintenance costs for this project include the expensed costs of operating and maintaining the system plus administrative and general costs. Major equipment replacement costs are normally capitalized and are considered separately. System control and dispatch costs are not included because it is believed that PSE control and dispatch costs would not be significantly affected by the proposed project. Generation integration costs are also excluded because no significant generation would be interconnected to the proposed project. Operating and maintenance costs were estimated from PSE operation and maintenance cost data appearing on page 321 of the PSE 2014 Federal Energy Regulatory Commission (FERC) Form 1 annual report. Administrative and General (A&G) costs (Form 1 page 323), excluding property insurance (entered separately in MicroFin) were calculated as a percentage of total O&M. That percentage was applied to transmission O&M, as calculated above, to obtain an estimate of transmission A&G. The transmission O&M estimate plus the transmission A&G estimate were then divided by total transmission asset value (Form 1 page 206) to obtain transmission O&M plus transmission A&G as a percentage of transmission capital cost.

Interim capital replacement cost: Interim capital replacement cost is the annual cost of replacing major components over the expected service life of the project. Information regarding utility interim capital replacement costs is scarce – these costs are rolled into annual capital costs that also include system expansion and disaster recovery expenditures. Reported interim capital replacement expenditures by North American utilities for substation and transmission assets are relatively high, about 5% of asset value annually. However, North American transmission systems are aging - the average age of large power transformers is reported to be 40 years. Because replacement costs increase with age, the levelized lifetime replacement rate for a new transmission line will be less than the replacement rate for a 40 year old facility. Assuming an exponential increase in replacement costs over the service life of a facility, a 5% rate at age 40 yields a levelized lifetime rate of 1.2% of asset value for a facility with an expected service life of 55 years (midpoint of PSE service life estimates).

Debt interest rate and financing fee: The average interest rate of 30-year PSE bonds issued from 2009 through 2014 is 5.48% (PSE FERC Form 1 page 256 and 257). To this was added 0.25% to account for the December 2015 Federal Reserve rate increase. The result was rounded to 5.75%. The same source was used to calculate an average debt placement fee of 1.03% (rounded to 1%) for the same bond issues.

General inflation rate: The forecast general inflation rate used by the Northwest Power & Conservation Council for its 7th power Plan (draft) was adopted for this study. That series is 1.6% for 2015, 1.7% for 2016, 1.6% for 2017, 1.7 % for 2018-2028 and 1.8% for 2029 and on.

Property tax: An average property tax rate for King County, Washington was calculated as the product of assessed property value to true property value (Property Tax Ratio) and the average King County property tax rate, as follows:

Property tax ratio for King Co.	93.800%	(WA Dept. of Revenue)
Average property tax rate for King Co.	1.014%	(www.smartasset.com)
Average property tax rate on true value	0.950%	

Property insurance: Total PSE insurance expenditures (2014 PSE FERC Form 1 page 323) were divided by total electric plant in-service asset value (Form 1 page 206) to yield a 0.06% rate based on asset value.

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EXPERIENCE

2011 - Present: President, Jeffrey C. King and Associates. Jeffrey C. King and Associates is a consulting firm engaged in energy-related analysis for public and private clients. The principal topics of the firm include energy policy analysis, technical, economic and environmental assessment of electric power generating technologies and power price forecasting.

2011: Planning Approaches for Water Resource Development in the Lower Mekong Basin. The purpose of this project, funded by USAID through AECOM International Development and Portland State University, was to propose and evaluate methods for improving planning for energy development of the Lower Mekong Basin (LMB). Mr. King was responsible for preparing the assessment of potential alternatives for power production in the LMB.

1984 - 2011: Senior Resource Analyst, Northwest Power Planning Council, Portland, Oregon. Mr. King was responsible for assessing the commercial availability, performance, economics, development potential and issues associated with development and operation of electric power generating resources. Mr. King was also responsible for the Council's forecast of wholesale electric power prices, using the AURORAxmp® Electric Market Model, a proprietary model of the western electric power system. The model is also used to assess the CO2 production and other effects of regulations and policies affecting the power system. Mr. King's activities included assessment and analysis, operation of computer models, preparation of issue papers, organization and chairing of advisory committees, administration of contracts, presentations to the Council and interested organizations, and work with utilities, government agencies, research organizations, resource developers and public interest groups. Information developed by Mr. King is widely employed by utilities, agencies and others outside the Council.

2008 - 2010: Chief Planner, National Energy Development Framework Project, State of Eritrea. Mr. King served as the chief planner for preparation of a 20-year energy development framework and five-year action plan for the State of Eritrea. The framework, funded by USAID, presents a vision for a future energy supply system for Eritrea to support an adequate, reliable, affordable, and sustainable energy supply for rural and urban areas, transportation, industry, and water resource, port and tourism development. Mr. King fashioned the contributions of specialists in various energy resources into a coherent description of Eritrean energy resource potential, formulated goals and objectives in response to concepts provided by the State of Eritrea, and lead the development of a proposed Eritrean energy future, action plan and framework for implementation.

1974 - 1984: Staff Engineer, Energy Systems Department, Battelle, Pacific Northwest Laboratories, Richland, Washington - Mr. King managed and contributed to projects involving assessment of the economic and environmental aspects of electric power conservation and supply resources and application of decision analysis techniques to energy policy and technology issues. Projects included the first assessment of conservation and generating resources for the newly-formed Northwest Power Planning Council, assessment of generating resource alternatives for the State of Alaska, assessment of decommissioning costs and priorities for retired nuclear facilities and analysis of high-level nuclear waste disposal alternatives.

1964 - 1970: Test Engineer, Nuclear Power Division, Puget Sound Naval Shipyard, Bremerton, Washington - Mr. King was responsible for the planning and execution of acceptance testing procedures for the construction, overhaul and refueling naval nuclear power plants.

EDUCATION

Bachelor of Science in Mechanical Engineering, University of Washington, Seattle, Washington. 1964.

Graduate Studies, Zoology, University of Washington, Seattle, Washington. (1970-1972).

Graduate Studies, Regional Planning, University of Pennsylvania, Philadelphia, Pennsylvania. (1972-1974).

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Sixth Northwest Conservation and Electric Power Plan (Document 2010-09). Northwest Power and Conservation Council. Portland, Oregon. January 2010. (Contributing author).

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