Susitna-Watana Cost of Power Analysis

Discussion Paper

Comments Solicited

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Summary

In this paper I present a simple analysis of the cost of the proposed 600-megawatt Susitna-Watana project from a utility ratepayer perspective. The reference case assumptions include a capital cost of 5.0 billion year 2008 dollars, 100% debt financing at 6%, and an on-line date of 2024. Under these assumptions plus others described below, the retail rate for Susitna power in 2024 at a Railbelt customer's meter would be about 40 cents per kilowatt-hour (kWh). By comparison, if natural gas is available to electric utilities in year 2024 at a price of about $13 per million btu, and neglecting potential carbon taxes, then the retail rate for power from a new conventional combined cycle gas turbine going online in 2024 would be about 21 cents per kWh.

If the State of Alaska were to contribute cash to cover part of the cost of the Watana project, required rates would be lower. For example, if the State paid 50% of the reference case cost of $5 billion, then a retail rate of about 23 cents per kWh would be required to cover the remaining 50%. The required outlay by the State would be the equivalent of about $15,000 per family of three Railbelt residents.

Introduction

The proposed Susitna-Watana (SW) project is an almost purely up-front capital investment with a 10-12 year lead time. One useful way to measure and express the cost of such a project is from a utility ratepayer perspective. Under standard utility ratemaking procedures, power generation infrastructure enters the utility's "rate base" when the project enters service. If the SW project requires outlays of several billion dollars during the next ten years and then enters service in 2024, what would be the level of consumer rates needed to recover the resulting utility cost of service?

I have constructed a very simple model of utility ratemaking that can be used to examine the implications for consumer rates of different assumptions about the SW project. The model provides a tool for exploring how different assumptions affect the cost of power to Railbelt ratepayers. The model is available for download from the at http://www.iser.uaa.alaska.edu/Publications/Susitna_cost_analysis_16July2012.xlsx

Ratemaking methodology

Utility rates in Alaska are based on the cost of service.[1] The cost of service in my model includes the following components.

Table 1

		Cost of service (COS) components used in simplified ratemaking model
		fuel
+		nonfuel operation and maintenance
+		depreciation of power production plant
+		interest on debt used to finance power production plant
=	**Power production cost of service**	
+	Transmission COS (operating and capital)	
+	Distribution COS (operating and capital)	
+	Admin & General COS (operating and capital)	
=	**Total cost of service**	
+	Authorized margins	
=	**Authorized total revenue requirement**	

For a nonprofit utility without equity investors, the funds known as "margins" can be thought of as a working capital expense or a financial "cushion" that is generally required by bondholders and/or granted by regulators to ensure that authorized revenues are more than sufficient to pay interest on long-term debt. Alaska utilities typically are authorized to collect sufficient revenue to offset about 1.3 times the amount of interest expense. The factor 1.3 is known as the "times interest earned ratio" or TIER. For example, as of 2012 Chugach Electric Association's approved revenue requirement was based on achieving a TIER of 1.3 [2,3].

[1] See, eg: Chugach Electric Association. 2012. TA-347-8. Semi-annual simplified rate filing. Especially Table 1 at page 49 of 214. http://rca.alaska.gov/RCAWeb/ViewFile.aspx?id=253d3650-b7c6-4e59-98c0-8fca94ea835d

[2] See, eg, Chugach Electric TA 347-8. Table 1 at page 49.

[3] RCA Staff Memorandum (Tariff Action Meeting Memorandum dated May 3, 2012.) Subject: TA347-8 Chugach Electric Association, Inc.'s SRF Tariff Filing for the Test Year Ended December 31,2011. "Chugach operates on a split Times Interest Earned Ratio (TIER) platform whereby the Commission has established a system-wide TIER of 1.30, based on a 1.10 TIER for wholesale customers, and a fioating TiER for retail custorners." p. 4. TIER = (Net Margins + Interest on Long-Term Debt) / (Interest on Long-term Debt)

Reference case assumptions

The following assumptions are used to generate the reference case.

Project size. This analysis is of the 600 megawatt “Low Watana Non-Expandable Alternative” presented in the HDR Conceptual Alternatives Design Report (2009, p. 16) and again in the AEA Preliminary Decision Document (AEA 2010) and in the AEA’s February 2012 presentation to the Anchorage Chamber of Commerce.

Pre-construction cost. I have assumed a pre-construction cost of zero in addition to the project costs discussed below. It is unclear whether the Watana-related expenses authorized by the Alaska Legislature to date are counted in these estimates.

Construction cost. I have assumed an overnight construction cost of $5.0 billion year 2008 dollars. This assumption is based on the $4.5 billion project cost that appears in the HDR Conceptual Alternatives Design Report (2009, p. 16) and re-appears in the AEA Preliminary Decision Document (November 2010, p. 2-4). In addition to the $4.5 billion direct construction cost I have added $500 million for required transmission upgrades needed to accommodate Watana power. This amount is based on a consideration of two data items:

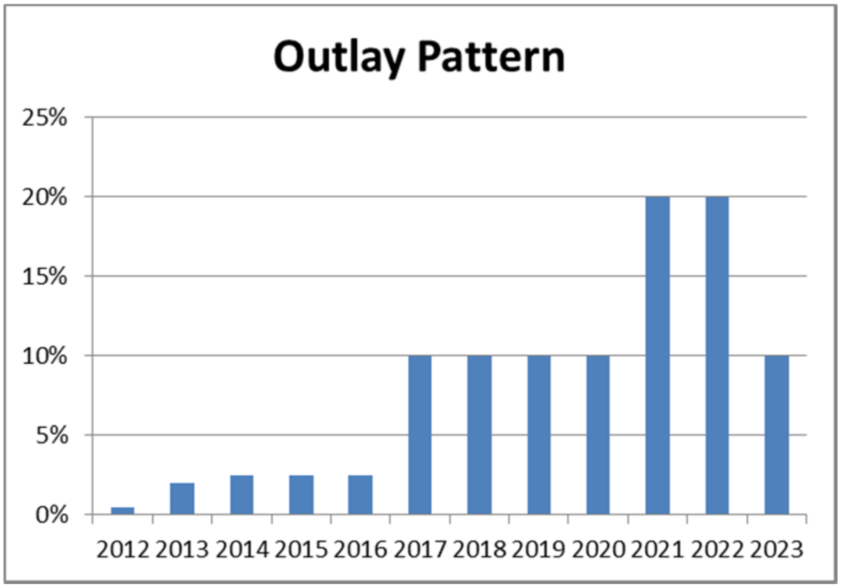
1) the Electric Power Systems (2009, p. 1) estimate of $889 million for required Railbelt transmission upgrades needed to accommodate Watana power, which likely includes some items that are already included in the $4.5 billion construction cost estimate; and
2) the difference -- equal to $424 million – between the AEA’s 2009 project memo figure for transmission of $648 milllion and the $224 million figure for transmission in the HDR November 2009 report.

Timeline. Based on the Susitna-Watana 2011 Report to Legislature (p 22), the following schedule is assumed:

Licensing period: 2012-2016
Construction period: 2017-2023
Operation begins: 2024

I assume that the pattern of construction outlays in real year 2008 dollars will be as follows:

Figure 1. Assumed outlay pattern (in year 2008 dollars)



Annual Energy output. 2,500,000 MWH. (AEA SW 2011 Report to Legislature, p. 6)

Inflation and financing during construction. An assumed inflation rate of 2.4% is applied to beginning in 2009 to all construction outlays and to future O&M costs and future transmission and distribution costs (Federal Reserve Bank of Philadephia 2011). All construction outlays are assumed to be financed by a construction loan or loans costing 6% interest; therefore the interest payments on accumulated outlays during construction are capitalized and added to the total rate base. This calculation is best explained by the following example of a project that has a one-year lead time.

January 1, Year 1: Borrow $100 @6% as a construction loan.

During year 1: Expend $100 on construction and accrue $6 of interest owed.

January 1, Year 2: Borrow $106 as a long-term bond. Repay accumulated principal and interest from Year 1 loan. Place the project in service. Declare the "rate base" to be $106.

During year 2: Begin collecting revenue sufficient to cover interest on the long-term bond plus annual depreciation of the rate base. Begin making long-term interest and principl payments against the $106 long-term debt.

Long-term financing. The project lifetime and the term of long-term bonds is assumed to be 50 years. The assumed interest rate is 6.0%. I assume that 100% of construction costs plus accrued interest during construction are rolled into the rate base and financed by long-term debt. Revenue requirements are calculated to recover 130% of annual interest costs (TIER = 1.30).

Transmission and Distribution. I assume a 95% "delivery factor" meaning that 95% of all kWh generated at the Watana project powerhouse are delivered to a Railbelt customer's meter. I have assumed the cost per kWh for transmission, distribution, admin, general, and customer expense to be 4.6 cents per kWh in 2011. This estimate is based on data from the Chugach Electric Association 2011 Annual Report (p. 8) showing the difference between the average revenue collected per wholesale kWh and per retail kWh.

The assumptions forming the reference case are summarized as follows.

Table 2. Summary of reference case assumptions

Item	units	value
Pre-construction cost	2008$ billion	0.0
Overnight capital cost	2008$ billion	5.0
Debt-financed fraction		100%
State AK cash fraction		0%
Nominal debt interest rate	nominal %	6.0%
Debt repayment period	years	50
Inflation rate	%	2.4%
Capacity	MW	600
Energy output at powerhouse	MWh	2,500,000
Fixed O&M per kW-yr	2008$/kW-yr	30.00
Annual O&M cost	2008$ billion	0.018
Depreciation lifetime	years	50
Required TIER		1.30
Ratio of kWh sold to kWh at powerhouse		0.95
Trans, dist'n, admin cost	2011$/kWh	0.046
Railbelt energy region population July 1, 2011		543,698

Reference case sample calculation

The methodology can be illustrated by stepping through the calculation of the revenue requirement per kWh for year 2024. Year 2024 is the assumed first year of operation and the first year of revenue collection. The steps are shown in the following table and then explained line by line.

Table 3. Calculation of year 2024 revenue requirement

line		item	units	2024 amount
1	**Operating Expenses**		$ billion	
2		Annual O&M	$ billion	0.026
3		***Subtotal Operating**	$ billion	**0.026**
4				
5	**Depreciation and rate base accounting**			
6		Rate base BOY	$ billion	8.017
7		Depreciation	$ billion	0.160
8		Rate base EOY	$ billion	7.857
9		***Total Depreciation**	$ billion	**0.160**
10				
11	**Interest**			
12		Interest on outstanding debt	$ billion	0.481
13		***Total Interest**	$ billion	**0.481**
14				
15	****Total Production Cost of Power**			**0.668**
16				
17	**Revenue Requirements**			
18	Recovery of direct production cost			0.668
19	Margin to meet TIER of 1.3			0.144
20	**Total Revenue Requirement for Production cost**			**0.812**
21				
22	MWh delivered from powerhouse		MWh	2,500,000
23	MWH retail sales at customer meters		MWh	2,375,000
24	Production Rev Reqt per kWh sold to retail customer		$/kWh	0.34
25	Trans, dist'n, admin cost		$/kWh	0.06
26	Total Rev Reqt = cost of power to retail customer		$/kWh	0.40
				12
		Variable	units	2024
	Debt service and debt principal accounting			
27		Debt principal BOY	$ billion	8.017
28		Debt service payment	$ billion	0.509
29		Interest	$ billion	0.481
30		Repayment of principal	$ billion	0.028
31		Debt principal EOY	$ billion	7.990

Line 2. Annual O&M = $18 million in year 2008 dollars escalated by inflation of 2.4% compounded for 16 years. [0.018 * 1.024^16 = 0.026]

Line 6. The rate base at the beginning of 2024 equals 8.017 billion dollars. This is the result of the construction outlay pattern during the years 2012-2023 with 1) each annual outlay escalated by the appropriate amount of inflation and 2) interest of 6% applied to and added on to the accumulating rate base at the end of each construction year.

Line 7. Depreciation = 1/50 of rate base amount. [8.017 * .02 = 0.160]

Line 8. The depreciated or net rate base at the end of the year = 8.017 – 0.160 = 7.857

Line 12. Interest = 6% of the beginning-of-year outstanding debt. [8.017 * .06 = 0.481]

Line 15. Production cost = O&M + depreciation + interest [.026 + .160 + .481 = 0.668] [displayed numbers are truncated to show only 3 decimal places so they do not appear to add exactly]

Line 19. Required additional revenue to meet the target TIER of 1.3 = 30% of annual interest charge. [0.481 * 0.3 = 0.144]

Line 23. Delivered electric energy = 95% of powerhouse energy [2,500,000 * 0.95 = 2,375,000]

Line 24. Production revenue requirement per kWh sold = line 20 divided by line 23 [$812 million / 2,375,000 MWh = 0.34 dollars per kWh]

Line 25. Transmission, distribution, admin revenue requirement = $.046 in year 2011 escalated by inflation of 2.4% compounded for 13 years. [0.046 * 1.024^13 = 0.06]

Line 26. Total cost of power to consumer = 0.34 + 0.06 = $0.40 per kWh

Line 29. Debt principal is accounted for and reduced according to a 50-yr amortization schedule.

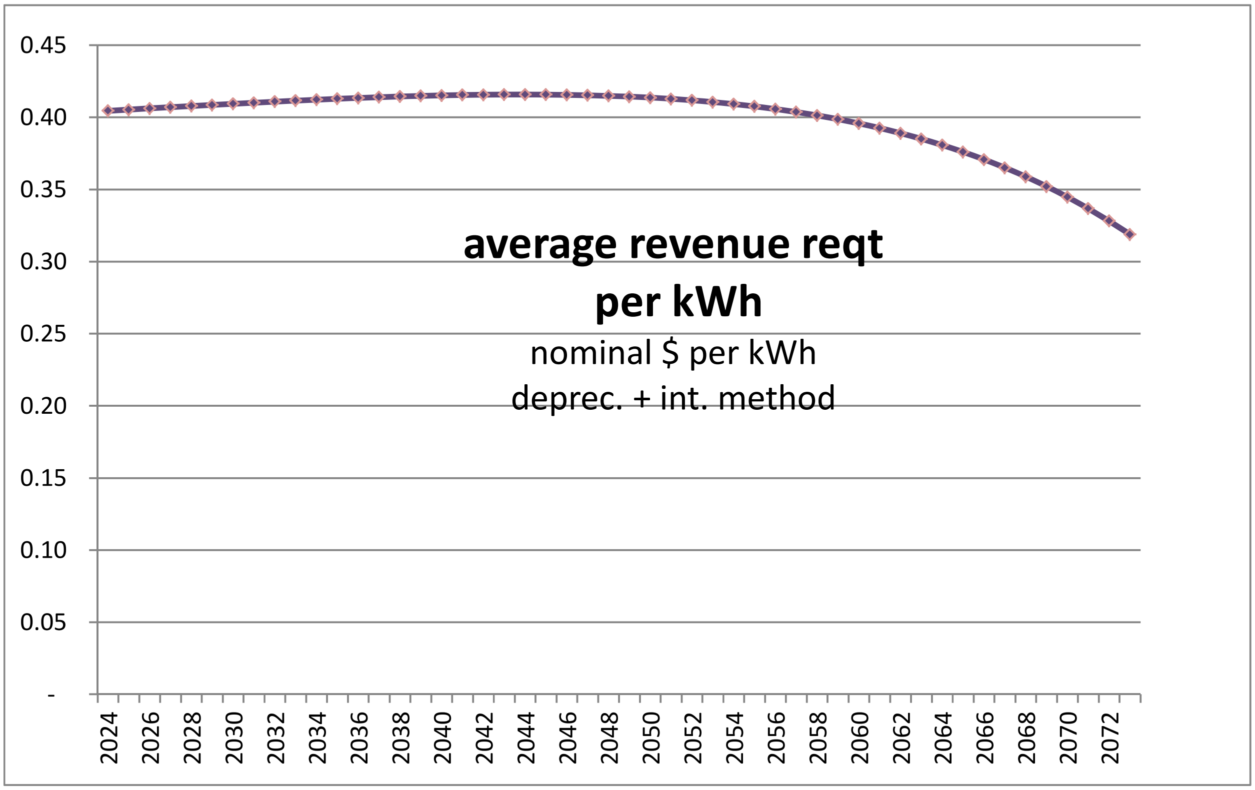
Reference case results

Using the reference case assumptions the required retail rate for Watana power in 2024 equals 40 cents per kWh. In subsequent years the required rate first increases as O&M and transmission and distribution costs increase with inflation and then declines as the required interest charges decrease. This progression is summarized in Table 4 and Figure 2.

Table 4. Cost of Watana power in future years

Cost of power to ratepayers under standard utility ratemaking		2024	2035	2050	2073
Production cost per retail kWh sold	$/kWh sold	0.34	0.33	0.30	0.12
plus: xmission, dist'n, admin	$/kWh sold	0.06	0.08	0.12	0.20
Cost of power to retail CEA customer	$/kWh sold	0.40	0.41	0.41	0.32

Figure 2. Reference case cost of Watana power at customer meter in future years



Comparison natural gas case G1

Because the cost of power from all sources is likely to increase with inflation and due to other cost increases, it is useful to compare the projected cost of Susitna-Watana power to a corresponding cost of natural gas-fired power. The critical uncertainty in making this comparison is, of course, the projected cost of natural gas. I have adopted the natural gas price projections used in the Black and Veatch Railbelt Integrated Resource Plan (RIRP)(Table 7-3)[4]. These projections are summarized in the following table.

Table 5. Assumed future natural gas prices for comparison case G1

B&V RIRP (nominal dollars)	2024	2030	2040	2050
Natural Gas $ per million btu	12.77	13.58	13.91	15.64

For the sake of comparison I assume that a 180-MW gas turbine could be built with a 4-year lead time beginning in 2020 and coming on line in 2024. The assumed capital cost

4 http://www.akenergyauthority.org/RIRPFiles/Alaska_RIRP_Final_Report_120409/AlaskaRIRPFinalReport-Part2of6.pdf

of $1,202 per kW in year 2010 dollars is based on a base cost of $900 per kW in 2009, escalated by 5% for contingency and by an additional 24% for the higher cost of Alaska construction.[5] The assumptions for this gas-fired plant and the resulting cost of power are as follows.

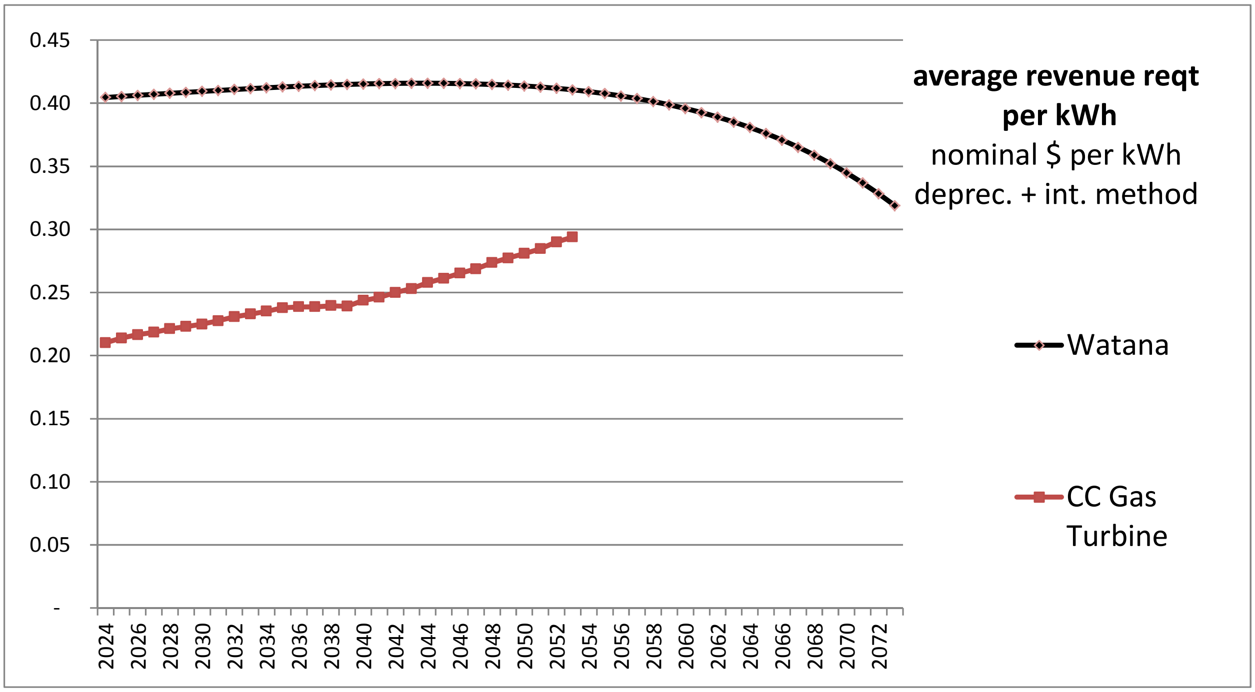
Table 6. Assumptions and results for comparison natural gas case G1
(combined cycle gas-fired 180 MW plant)

Assumptions		units	input	calculated	
	capacity	MW	180		
	Annual capacity utilization factor		0.85		
	Annual energy output at busbar	MWh		1,341,198	
	Overnight capital cost per kW	2010$/kW	1,202		
	Overnight capital cost for plant	2010$ billion		0.216	
	lead time yrs		4.0		
	fixed O&M	2010$/kW-yr	9.5		
	variable O&M	2010$/MWh	2.00		
	Annual O&M cost	2010$ billion		0.004	
	Debt-financed fraction		100%		
	State AK cash fraction		0%		
	Nominal debt interest rate	nominal %	6.0%		
	Debt repayment period	years	30		
	Inflation rate	%	2.4%		
	Depreciation lifetime	years	30		
	Required TIER		1.30		
	Ratio of kWh sold to kWh at busbar		0.95		
	Trans, dist'n, admin cost	2011$/kWh	0.046		
	Heat rate	btu/kWh	8600		
	Natural gas price in 2024	$ per million btu	12.77		
Results					
	Cost of power to ratepayers				
	under standard utility ratemaking		2024	2035	2050
	Production cost per retail kWh sold	$/kWh sold	0.15	0.16	0.16
	plus: xmission, dist'n, admin	$/kWh sold	0.06	0.08	0.12
	Cost of power to retail CEA customer	$/kWh sold	0.21	0.24	0.28

Figure 3 compares the cost of power for the reference Watana case and the comparison G1 gas-fired case. The gas-fired plant has an assumed 30-year lifetime.

[5] Mark Foster, personal communication, April 2012, based on MAFA, Analysis of Natural Gas Combined Cycle Alternatives, MEA Territory, 2010

Figure 3. Reference case compared to natural gas case G1



Watana alternative case WA1

This case (named WA1) assumes slightly less optimistic parameters:

Construction cost = $6.0 billion

Interest rate = 7.0%

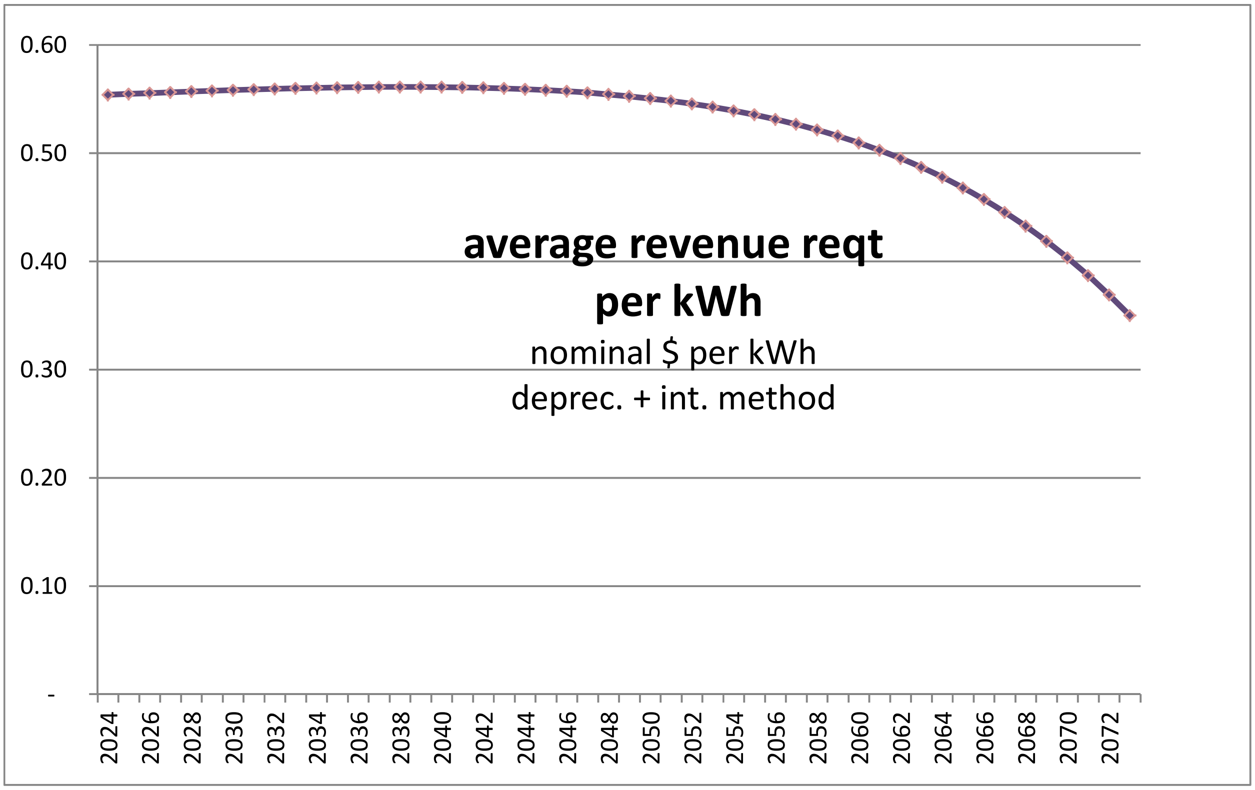
Ratio of power at customer meter to power at powerhouse = 92%

With these assumptions, the cost of power would be 55 cents per kWh in year 2024.

Table 7. Assumptions and results for Watana alternative case WA1

Assumptions						
	Item	units	value			
	Pre-construction cost	2008$ billion	0.0			
	Overnight capital cost	2008$ billion	6.0			
	Debt-financed fraction		100%			
	State AK cash fraction		0%			
	Nominal debt interest rate	nominal %	7.0%			
	Debt repayment period	years	50			
	Inflation rate	%	2.4%			
	Capacity	MW	600			
	Energy output at powerhouse	MWh	2,500,000			
	Fixed O&M per kW-yr	2008$/kW-yr	30.00			
	Annual O&M cost	2008$ billion	0.018			
	Depreciation lifetime	years	50			
	Required TIER		1.30			
	Ratio of kWh sold to kWh at powerhouse		0.92			
	Trans, dist'n, admin cost	2011$/kWh	0.046			
	Railbelt energy region population July 1, 2011		543,698			
Results						
	Cost of power to ratepayers					
	under standard utility ratemaking		2024	2035	2050	2073
	Production cost per retail kWh sold	$/kWh sold	0.49	0.48	0.43	0.15
	plus: xmission, dist'n, admin	$/kWh sold	0.06	0.08	0.12	0.20
	Cost of power to retail CEA customer	$/kWh sold	0.55	0.56	0.55	0.35

Figure 4. Alternative case WA1 cost of Watana power at customer meter in future years



Discussion relevant to case WA1

Timeline. The reference case timeline appears optimistic. The HDR Susitna Hydroelectric Project Conceptual Alternatives Design Report Final Draft (HDR 2009) stated that "The licensing process from start to FERC order is estimated at 7 to 10 or more years."[6] In order for a license to be issued in early 2017, one has to assume the low-end 7-year licensing time frame and also that this 7-year process began in January 2010. A longer timeline would result in a higher rate base. A longer timeline could be modeled explicitly but here it is proxied as a rationale for using and increased value for the capital cost.

Construction cost. Foster (2011, p. 7) refers to a construction cost of $4.8 billion – rather than 4.5 billion -- as the AEA's cost number presented to the Alaska Legislature in early 2011. HDR in its March 2009 Susitna Hydroelectric Project Evaluation (p. 3) for AEA estimated the construction cost of a 600 MW Watana project as $6.9 billion, which number appears to include necessary Railbelt transmission upgrades.

[6] HDR 2009 p. 17

It is possible that cost estimates reflect the depressed economy of the Great Recession and that construction costs will rebound in real terms during the next ten years. According to one major global construction consultancy, “The global construction market is forecast to grow by up to 5% in 2012 and the rate of increase is likely to outpace that of global GDP over the next 10 years.”[7]

Prior to the 2008 recession there had been significant cost increases in utility generation project inputs. For example, the price of cement and crushed stone increased by 30% between 2004 and 2006.[8] The same report (Brattle Group 2007) noted that “Manufactured components of generating facilities—large pressure vessels, condensers, pumps, valves—have also increased sharply since 2004.”[9]

The U.S. Energy Information Administration increased its estimate of overnight capital cost for conventional hydropower by 32% for use in the 2011 Annual Energy Outlook, as compared to the estimate used for the 2010 AEO.

Interest rate. Interest rates for bond financing are currently at historically low values due to the recession and to policy choices of the U.S. Federal Reserve. Notwithstanding these low short-term rates, Chugach Electric recently completed a bond issue for $250 million at the rate of 4.36%.[10] It therefore seems plausible that for a multi-billion dollar bond issue that is tied to revenue from a single specific project with a 7-10 year lead time the required interest rate could be above 6%. The USDA Rural Utilities Service has been mentioned (AEA Report to the Legislature) as a potential subsidised funding source. However, the FY11 expenditure for RUS loan disbursements was $7.0 billion for the entire U.S. (Office of Management and Budget 2012, p. 70). It is unclear whether RUS would be willing to allocate 20-30% of its national disbursements to a single project serving consumers half of whom reside in a city of almost 300,000 people.

[7] Bruce Shaw Handbook 2012. p. 6
[8] Brattle Group 2007. p. 17.
[9] Brattle Group 2007. p. 18

[10] Chugach Electric Ass’n press release dated January 11, 2012. http://www.chugachelectric.com/media-room/press-releases/archives/2012/1/11/chugach-completes-250-million-financing

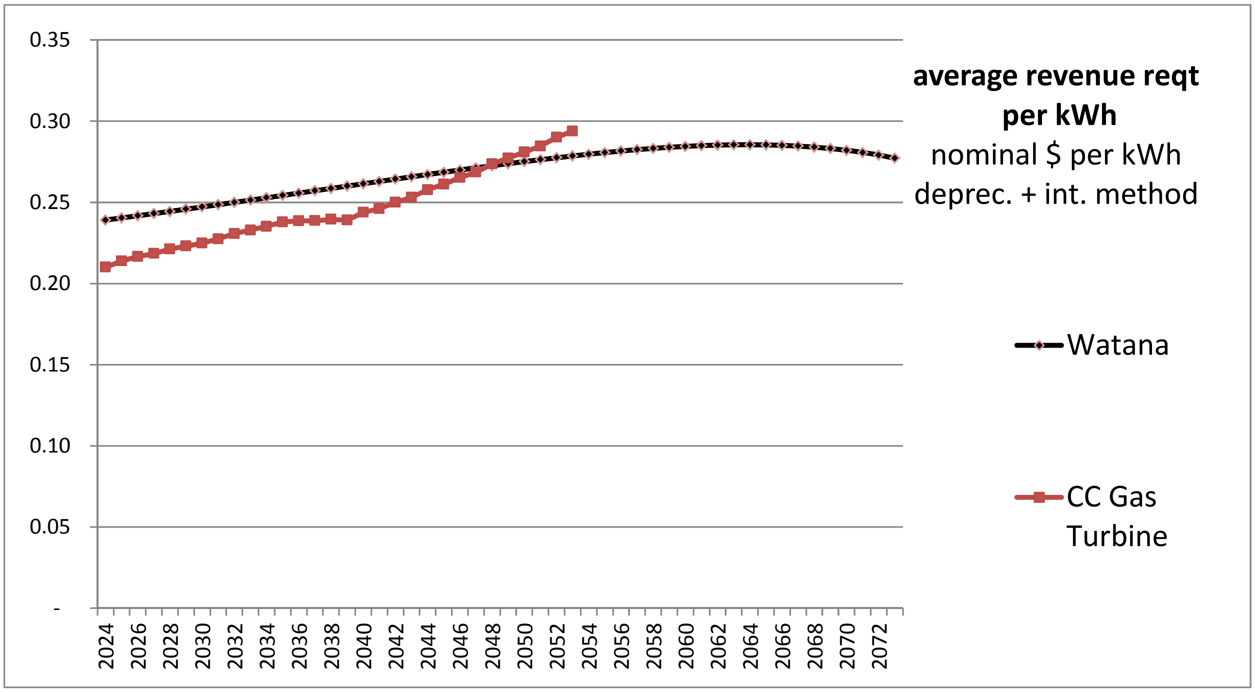
Watana alternative case WA2

This case (named WA2) assumes that the State of Alaska pays 50% of the construction cost as a direct cash contribution. All of the other assumptions are the same as for the reference case. The resulting cost of power is 24 cents per kWh in 2024, which is roughly the same as the cost for the natural gas comparison case developed above.

Table 8. Assumptions and results for Watana alternative case WA2
(State pays 50% of construction cost)

Assumptions						
	Item	units	value			
	Pre-construction cost	2008$ billion	0.0			
	Overnight capital cost	2008$ billion	5.0			
	Debt-financed fraction		50%			
	State AK cash fraction		50%			
	Nominal debt interest rate	nominal %	6.0%			
	Debt repayment period	years	50			
	Inflation rate	%	2.4%			
	Capacity	MW	600			
	Energy output at powerhouse	MWh	2,500,000			
	Fixed O&M per kW-yr	2008$/kW-yr	30.00			
	Annual O&M cost	2008$ billion	0.018			
	Depreciation lifetime	years	50			
	Required TIER		1.30			
	Ratio of kWh sold to kWh at powerhouse		0.95			
	Trans, dist'n, admin cost	2011$/kWh	0.046			
	Railbelt energy region population July 1, 2011		543,698			
Results						
	Cost of power to ratepayers					
	under standard utility ratemaking		2024	2035	2050	2073
	Production cost per retail kWh sold	$/kWh sold	0.18	0.17	0.16	0.08
	plus: xmission, dist'n, admin	$/kWh sold	0.06	0.08	0.12	0.20
	Cost of power to retail CEA customer	$/kWh sold	0.24	0.25	0.28	0.28
	State AK payment per Railbelt family of 3	2008$	13,794			

Figure 5. Comparison of Watana with 50% State cash contribution (case W2) to natural gas case G1



As Table 8 shows, the outlay of $2.5 billion by the State of Alaska as a cash contribution would equate to a payment of about $14,000 per Railbelt family of 3. There are two other ways of measuring the opportunity cost of a state cash contribution. One way is to consider that the money could be deposited into the Permanent Fund. (Between 1981 and 1987 more than $3 billion was deposited into the fund by legislative action[11]). The average annual rate of return earned by the Alaska Permanent Fund over the 27.5 years ending June 30, 2011 is 9.1%[12]. The stated benchmark target return is 9.6%. At the historical average rate of 9.1%, a deposit of $2.5 billion could earn a nominal return of $227 million dollars per year. That amount equates to $418 per Railbelt resident per year or $1,254 per household of 3 people per year. These are nominal dollar returns; "inflation-proofed" returns would be lower.

A second way of measuring the opportunity cost of a state cash contribution is to consider what other large capital projects could be undertaken with the same amount of money. It is unlikely that the State could spend $2-3 billion on the Susitna-Watana dam

[11] Goldsmith, Scott. Permanent Fund Historical Data. Spreadsheet compilation from AKPF annual reports. Available from the author. Also: http://www.mrbenshoof.com/Finance/PFD%20History.pdf documents $3 billion of special appropriations between 1981 and 1986.

[12] Alaska Permanent Fund *2011 Annual Report* p. 8

and still have enough cash left over to make a major contribution toward an in-state gasline or other similar energy delivery project.

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