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BEFORE THE DEPARTMENT OF WATER RESOURCES

OF THE STATE OF IDAHO

IN THE MATTER OF APPLICATION FOR PERMIT NOS. 63-34403, 63-34652, 63-34897 AND 63-34900 IN THE NAME OF CAT CREEK ENERGY LLC	SECOND DECLARATION OF ANTHONY M. JONES IN SUPPORT OF SBAR RANCH, LLC AND THE DISTRICT AT PARKCENTER, LLC's PETITION FOR REVIEW OF ORDER RE: SBAR RANCH, LLC AND THE DISTRICT AT PARKCENTER, LLC's RENEWED MOTION FOR RULE 40.05.B ORDER FOR APPLICANT TO SUBMIT COMPLETE RULE 40.05 INFORMATION

ANTHONY M. JONES, being first duly sworn, deposes and says:

1. This is my Second Declaration submitted in connection with the above-captioned matter and it supplements my prior Declaration submitted on June 30, 2020. SBar Ranch, LLC and The District at ParkCenter, LLC's legal counsel requested that I review and provide my opinions on the financial information Cat Creek Energy, LLC ("CCE') has uploaded to its online repository as of September 15, 2020, (CCE-D-00001 to CCE-D-00046) including the September 8, 2020, Primary Energy letter to CCE added to the repository on that date (CCE-D-00044 to CCE-D-00046, hereinafter "PE Letter"). In addition to reviewing these documents, I

also have reviewed Cat Creek's Applications for Water Right Permit Nos. 63-34403, 63-34652, 63-34897 and 63-34900, Idaho Code 42-203A(5)(d), Idaho Water Appropriation Rule 40.05(f) and *Shokal v. Dunn*, 109 Idaho 330, 707 P.2d 441 (1985), as well as other publicly available information and pertinent materials available to me.

2. I reached the opinions presented here by applying accepted economic methodology. The opinions expressed here are my own and are based on the data and facts available to me at the time of writing. The opinions expressed here are based on my 35 years of experience in the energy industry, 20 years focusing on open market energy prices, and a cash flow model developed using the data and facts available to me at the time of writing. I hold the opinions set forth here to a reasonable degree of economic science certainty.

3. As discussed more fully below, in my professional opinion:

a) The PE Letter is not an actual financial commitment letter, nor has CCE provided "the financial statement of the lender," as required by IDAPA 37.03.08.40.05.f(i) ("Rule 40.05(f)(i)"); and

b) The PE Letter together with the other financial information CCE has posted to date on its repository actually support the conclusion that CCE's pumped storage hydro ("PSH") project will not be financially viable as its costs will exceed revenue and, as a result, it is unlikely that CCE ultimately will be able to obtain the kind of private financing described in the PE Letter over the next 20 or more years.

4. The PE Letter actually does not expressly or implicitly commit Primary Energy ("PE") or any other entity to fund the CCE PSH. The best way to characterize the letter is an offer on the part of PE to market CCE's debt. The concept of the letter is fundamentally the same as a real estate agent offering to list a person's house. In this respect, PE "supports" the project and touts its contacts with other entities that finance energy projects, but there is no promise made, explicit or implicit, that those parties ultimately will provide funding for the CCE PSH project. Further, there is no indication that CCE actually has contracted with PE for

those services. The PE Letter is also not a professional appraisal of the potential of the project to attract investors or ultimately to operate profitably. Thus, the PE Letter is not a "financial commitment letter" in that it is not an actual commitment to provide project financing. In summary, the PE Letter is simply a potential offer of assistance from one business to another. Assistance may be necessary in securing financing, but it is not the same as an actual commitment of adequate financing. PE offers nothing in the form of a material financial commitment to the CCE PSH project. On this basis, the PE Letter does not satisfy CCE's financial resources information requirements of Rule 40.05(f)(i).

5. The PE Letter also does not meet "the financial statement of the lender" required to accompany the financial commitment letter under Rule 40.05(f)(i). The term "financial statement of lender" typically refers to an audited combination of reports that include balance sheets, cash flow statements, annual reports, major sources of income, and other details sufficient to establish the ability of the lending company to perform in the required capacity. The PE Letter only states that PE's "Sponsors are experienced investors in assets similar to the Cat Creek Energy projects, with combined assets under management of over a $ 1.0 trillion." That statement falls well short of satisfying the "financial statement of lender" requirement.

6. On this basis, it is my opinion that the PE Letter together with the other financial information on the CCE repository does not satisfy Rule 40.05(f)(i) and CCE has not yet met the financial resources information requirements of Rule 40.05(f)(i).

7. The PE Letter explains that the construction financing will be separate and apart from long term operational/ownership financing; and that the maximum amount CCE can ultimately expect to borrow is from 70% to 75% of the total expected project cost. According to the PE Letter, project funding will occur in three parts:

a) 25% of capital expenditures (or about $400 million) from equity investors.

b) A short-term construction lender consisting of "either traditional banks that support construction projects or institutional lenders."

c) The remaining 75% of capital expenditures from long term debt "which would be funded after commissioning of the project through the institutional debt market."

8. The PE Letter states without any factual support, "that the project can support about 70% to 75% leverage, which would be funded after commissioning of the project through the institutional debt market (the Term Loan B market)." Nevertheless, using the 75% of leveraging to CCE's estimated $1.577 billion project cost, means the remaining 25% balance of about $400 million must be supplied by equity parties.[1] Thus, assuming spending on the project occurs in roughly equal amounts for each of the five years of construction, CCE, in one capacity or another, needs to show liquid assets dedicated to its PSH project on the order of $80 million to begin construction and access to an additional $320 million, or more, over the course of the five year construction schedule.[2]

9. Mr. Faulkner, in filings to date on behalf of CCE, claims to have invested $18.6 million on feasibility and engineering studies, legal fees, filing fees, etc., dedicated to furthering the CCE PSH project.[3] However, Mr. Faulkner's asserted investment to date is only about one

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[1] The PE Letter uses $2.4 billion for the cost of the project. In earlier IDWR filings, CCE estimated the overall cost of the PSH and consumptive water use project to be $1.577 billion. (CCE-D-00023-24; Second Declaration of James Carkulis (Redacted) at 2 and Appendix A). The PE Letter's value is more current and potentially more accurate than CCE's earlier estimate or, perhaps, it includes the costs of the separate wind and solar proposals. To be conservative, I used the $1.577 billion cost estimate in my analysis.

[2] CCE, Reply in Support of Motion for Protective Order at 22.

[3] Declaration of John L. Faulkner and CCE-D-00036.

percent of the expected $1.6 Billion cost of the project, and far short of the $400 million in seed equity the PE Letter identifies as necessary to build and operate the project.

10. To date CCE has provided no documentation that Mr. Faulkner and/or his associates have financial reserves on the level the PE Letter indicates will be necessary. The lack of proof that CCE has the necessary financial reserves available, or at least equity commitments of this level, means that the PE Letter actually establishes the inadequacy of CCE's current financial resources. This also means that CCE does not meet the *Shokal v. Dunn* "extent of the applicant's own investment" test.

11. At this point in time, none of the three aspects of project financing laid out in the PE Letter have been met. There is no evidence that CCE has $80 million to $400 million in liquid assets dedicated to the project and no evidence that investors of that level are actually on board. The PE Letter together with the other information currently in CCE's repository, rather than establishing it is reasonably probable that CCE will obtain the necessary financing, actually highlights that CCE does not have the necessary equity commitments to obtain the financing for the project.

12. The operating concept of PSH is, as the term suggests, a device for storing energy for use at a later time. Historically, PSH projects were usually built in a symbiotic fashion with one or more thermal plants, such as coal or nuclear plants, as a means of extending the limited efficient operating range of those plants. The benefit as well as the cost of operating such PSH was usually evaluated as part of the complete thermal plant/PSH package and if done properly, the total benefit exceeded the sum of the cost of the individual parts.

13. PSH projects such as the one CCE PSH is proposing, owned and operated independently from any specific energy production facility, have a slightly different operating

philosophy. They are designed to shift energy produced during times of low priced power (low demand relative to total system production) to times of high priced power (high demand relative to total system production). More succinctly, projects like the proposed CCE PSH arbitrage energy market price swings. They attempt to buy low and sell high. The CCE PSH project must buy low and sell high to survive.[4]

14. At the individual plant level, PSHs like CCE's are net consumers of electricity. On the Western Grid, with current and anticipated future open market price dynamics, independent PSH, such as the one CCE is proposing, cannot operate profitably. The arbitrage possibilities in the market are insufficient to cover the debt service requirements and operating costs. In the words of Idaho Power Company (IPC), "Historically, the differential between peak and off-peak energy prices in the Pacific Northwest has not been sufficient enough to make pumped storage an economically viable resource."[5]

15. It is my opinion that independently operated PSH projects like the one CCE is proposing are unlikely to be financially viable for the reasonably foreseeable future of 20 years or more. My opinion is based on a cash flow analysis that explores the sufficiency of market prices to cover CCE's expected PSH costs. My analysis on which this opinion is based, relies on the information currently on CCE's repository and incorporates the following conservative assumptions:

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[4] At Pre-Hearing Conferences, CCE has confirmed that its PSH will be operated independently from any other power generating facilities.

[5] Idaho Power, 2019 Integrated Resource Plan ("IRP") at 54.

a) Any costs not directly related to debt service, investor dividends, potential revenues, and potential pumping costs are not included.

b) Salaries, maintenance costs, emergency repairs, and unscheduled down time are not included. This analysis assumes the CCE PSH project runs without interruption, 365 days a year, for 35 years.

c) Optimistic low range interest rates and maximum long range amortization schedules are used to minimize estimated annual debt service payments.

d) The construction costs of the irrigation portion of the project estimated at 29 percent are not included and, for the purposes of this exercise, assumes the irrigation portion of the project will break-even financially in the interest of minimizing the total amount of debt and operating costs the PSH must support.[6]

e) The higher (720 MW) of two different CCE listings for the potential generating capacity of the PSH is used to make sure the model does not understate the PSH project's revenue generating potential. [7]

f) An operating efficiency value of 85% which is two percentage points higher than Idaho Power's highest suggested efficiency rating for PSH is used to make sure the model does not understate the PSH project's revenue generating potential. [8]

16. Based on the information on the CCE repository and these conservative assumptions, I calculated that the CCE PSH will face annual debt/dividend service obligations in excess of $53 million, or approximately $20/MWh. The cost calculations, data and assumptions associated with this analysis are further detailed in Appendices I-IV, attached hereto.

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[6] CCE is silent on the manner in which the irrigation portion of the project interfaces with the PSH portion. For example, presumably, the process of sending irrigation water back to the river will be used to generate electricity but CCE is silent on whether these proceeds will be used to offset irrigation costs or will be directed to PSH accounts. *See* Appendix II hereto for how the 29% estimate was calculated.

[7] Application for Permit No. 63-34403 lists capacity as "600 MW." FERC, 2018 Preliminary Permit Application ("PPA") (CCE-C-01172-01196) lists capacity as "720 MW." This analysis used 720 MW because the higher number is more generous to CCE.

[8] Idaho Power, 2019 IRP at 54 ("Typical [PSH] round-trip cycle efficiencies are between 75 and 82 percent."

17. On the revenue side, assuming the PSH generates power at a rate of 720 MW for 10 hours per day, 365 days per year, it will produce ~2.6 million MWh per year. If CCE sells the power during the 10 highest priced daily hours on the CAISO, NP15, Day Ahead Market, for an average of $42.3/MWh, the CCE PSH will gross $111 million per year.

18. Offsetting the PSH energy sales will be the reciprocal cost of energy necessary to refill the upper reservoir. With efficiency losses it will require roughly 3 million MWhs of energy to recharge the amount of water in the upper reservoir necessary to produce the 2.6 million MWh/yr listed in the previous paragraph. If CCE purchases the power during the 12 lowest priced hours on the CAISO, NP15, Day Ahead Market, for an average of $29/MWh, CCE will spend about $87.6 million per year refilling the reservoir. The total annual cost of pumping plus debt/dividend service, will amount to about $141 million per year, or $54/MWh. With revenue of only about $111 million per year, the CCE PSH will lose nearly $30.2 million per year, a loss of more than $11/MWh.

19. To summarize, this analysis is based on debt structures equal to or slightly better than those listed by CCE. It assumes the project works perfectly with no down time, 365 days a year, for 35 years. It assumes management and staff work for free and there are never any costs for maintenance and repair. This analysis is conservative in the extreme in CCE's favor and the results still show the project losing $30 million per year. That is the sort of calculation that any investor or loan officer fulfilling their fiduciary responsibilities would rely on to deny funding for this project.

20. Historic pricing trends establish that, if anything, future differences between low price hours and high price hours will continue to converge. Thus, in my opinion, it is unlikely that prices will change significantly enough over the next 20 years or more to make CCE's PSH

profitable. *See* Appendix IV hereto. The threshold increase in prices sufficient for CCE PSH profitability would require an increase in excess of 25%, from the low $40/MWh range to the mid $50MWh range or higher. Any possible claims that market prices will soar to those levels as thermal plants are retired ring hollow in the face of recent reports such as those out of New Mexico where a four part solar project producing 650MW is replacing a coal fired plant: "In terms of wholesale energy prices, the Arroyo project comes in at $18.65 per MWh, the Jicarilla project at $19.73, the San Juan Solar I and Jicarilla Solar I, respectively, at $26.65 and $27.35. In comparison, coal-fired generation runs $66 to $112 per MWh, and combined-cycle gas fired generation is $44 to $64 MWh." https://pv-magazine-usa.com/2020/10/12/solar-plus-storage-replaces-coal-plant-in-new-mexico-makes-carbon-capture-retrofit-moot/. For reasons such as these, FERC frowns on unsubstantiated claims of future rates of inflation for energy prices that are substantially higher than the recent historic record.

21. For CCE's proposed PSH the absolute price floor is $20.4/MWh, the minimum price necessary to cover annual debt/dividend service requirements even if power for pumping water into the upper reservoir is free of charge. *See* line 25 in Appendix I. There are a couple problems with that $20.40/MWh number. The first is that selling power for $20.40/MWh or higher on the western grid is not a sure thing. The average high load hour price on the MID-C trading hub for the last four years was only $23.50, only about $3 above the CCE price floor. (Again, $20.40 does not include wages, M&O, etc.) Marcus Harris of Bonneville Power Administration confirmed the matter in an email earlier this year. BPA sells about 25% of its

power on the MID-C hub and over the past five years has only averaged $19/MWh.[9] *See* Appendix IV.

22. For these reasons, in my opinion, the economic outlook for CCE's PSH is bleak for the reasonably foreseeable future, over the next 20 years or more, and for this reason it is unlikely that CCE will be able to operate profitably or obtain the necessary financing.

I declare under penalty of perjury that the foregoing is true and correct.

DATED THIS 3rd day of November, 2020.

Anthony M. Jones

[9] Marcus Harris, Budget Officer and Manager of Financial Planning & Analysis, Bonneville Power Administration, maharris@bpa.gov, email , Nov 22, 2019, at 1:59 PM.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the date indicated below I caused to be served a true copy of the foregoing SECOND DECLARATION OF ANTHONY M. JONES IN SUPPORT OF SBAR RANCH, LLC AND THE DISTRICT AT PARKCENTER, LLC'S PETITION FOR REVIEW OF ORDER RE: SBAR RANCH, LLC AND THE DISTRICT AT PARKCENTER, LLC'S RENEWED MOTION FOR RULE 40.05.B ORDER FOR APPLICANT TO SUBMIT with Appendices 1-IV by email addressed to the following:

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Dated: November 3, 2020

Dana L. Hofstetter

APPENDIX I - CAT CREEK ENERGY CASH FLOW

Pumped Storage Hydro

Annual Net Operating Revenue vs. Debt/Dividend Service Requirements

Line #	Notes	Line Items	$	Interest Rate	Term
		Maintenance and Plant Cost			
1	1	**Estimated Cost ($)**	**$1,577,907,500**		
2	2	Sales Tax (%)	6%		
3	3	Sales Tax ($)	$0		
4		Cost Plus ST	$1,577,907,500		
5					
6	4	Accumulated Construction Interest	$116,273,219	3.56%	5 Yrs.
7		Cost, including Id Sales Tax and Construction Capital	$1,694,180,719		
8					
9	5	Percent of Cost Allocated to PSH	71%		
10		Debt Allocated to PSH	$1,201,798,820		
11	6	Equity Portion (25%)	$300,449,705		
12	6	Conventional Debt Portion (75%)	$901,349,115		
13					
14	7	Annual Payment to Equity Dividends	$8,262,367	2.75%	
15	8	Annual Payment to Conventional Debt	$45,420,182	3.56%	35 Yrs.
16		**Total Annual Debt/Dividend Service**	**$53,682,549**		
17		**$/MWh**	**$20.43**		
18					
19					
20	9	Wages	$-		
21	9	Other	$-		
22		M&O	$-		
23					
24		**Total Debt/Dividend Service plus M&O**	**$53,682,549**		
25		**$/MWh**	**$20.43**		
26					
27					
28					

29		**Cash Flow From Operations**	
30		**Generation**	
31	10	Capacity MW	720
32	11	Hrs / Day	10.0
33	12	Days /Yr	365
34		Annual Prod (MWh)	2,628,000
35			
36	13	**Generation $/MWh**	**$42.28**
37		**Revenue from Generation**	**$111,121,278**
38			
39		**Pumping**	
40	10	Pumping Rate MW	720
41	14	Hrs / Day	11.50
42	12	Days /Yr	365
43		Annual Pumping (MWh)	3,022,200
44			
45	13	**Pumping $/MWh**	**$28.99**
46		**Annual Pumping Cost**	**$87,598,496**
47			
48		Total Annual Cost – Debt Service/Pumping	**$141,281,045**
49		Cost of Production ($/MWh)	$53.76
50			
51		Generation minus Pumping Cost	$23,522,782
52		$/MWh	$8.95
53			
54			
55	15	**Annual Profit (Loss)**	**$(30,159,766)**
56		**$/MWh**	**$(11.48)**

Notes:

1 Cat Creek Energy, CCE-D-00023-24 and Second Carkulis Declaration

2 https://tax.idaho.gov/i-1023.cfm.

3 According to JAK | Taxpayer Services Representative, Idaho State Tax Commission | TRU/TPS, taxrep@tax.idaho.gov, 11/02/2020, "There is no sales tax exemption for power plants in Idaho. If you have a contractor providing equipment and materials, they would need to pay sales or use tax on those items." However, the lack of detail on CCE budget documents makes it impossible accurately separate taxable vs. non-taxable items. In deference to CCE, RME assumes all relevant sales tax is included in the budget estimate.

4 Assumes debt accrues in equal 5-year increments. Five years based on: CCE, Reply in Support of Motion for Protective Order, July 13, 2020, at p. 22. For more detail on the interest rates please see note 8 below.

5 Allocated 80% of the cost of the reservoir and roughly 5% of the cost of everything else to non-PSH to arrive at an overall ~71% allocation of total costs to the PSH portion of the project. Please see Appendix II.

6 PE Letter.

7 Dividend rate based on Idaho Power's share dividend. The most common way for equity partners to benefit from their investment is in the form of stock appreciation and/or dividends. Given the bleak results of this cash flow analysis, stock price appreciation seems unlikely. Absent that, CCE will have to pay dividends to shareholders.

8 The average of Conventional Finance and Water Related Deb (weighted by the amount of debt), claimed by CCE in CCD-D-00023, Financing Sources and Uses Cat Creek Energy Project.

9 The point of this exercise is to explore the ability of the market to support debt and equity service related to the CCE PSH project. To be conservative, all other costs were zeroed out.

10 CCE IDWR Application for Water Right Permit No. 63-34403 lists capacity as "600 MW".
FERC, 2018 PPA, CCE-C-01172-01196, p. 1, lists capacity as "720 MW".
720 MW was used as the basis for calculation in that it was the more favorable to CCE.

11 PSH must necessarily spend more time/effort pumping than generating. The efficiency difference between the two modes limits operation during "shoulder" hours when there is no advantage to operate in either mode. A maximum of about 10 generating hours are estimated, thus requiring at least 11.5 hours to refill the reservoir, leaving 2.5 hours of idle time.

12 One of the critical issues for any large manufacturing plant is the amount of time it is up and running and "absorbing" overhead. Downtime for maintenance and repair of 15% or greater is not unusual. However, it is assumed the CCE PSH runs perfectly, 365 days per year, for the life of the project.

13 Appendix III.

14 CCE is silent on the potential efficiency of this PSH. In a somewhat dated article, the Bureau of Reclamation talks of 75% efficiency ratings for PSH. "Estimating Reversible PumpTurbine Characteristics, US Bureau of Reclamation, Engineering Monograph No. 39, p. 1.
More currently, Idaho Power suggests that efficiencies may not have improved dramatically. "Typical round-trip cycle efficiencies are between 75 and 82 percent." Idaho Power 2019 IRP, Pumped-Storage Hydro, p. 54.
It is assumed here CCE would achieve 85% efficiency, expressed as requiring an addition of 15% of time for every hour of generating time.

15 The results on this page are based on 11-year averages of high price hours (HPH) vs. low price hours (LPH).

APPENDIX II – COST ALLOCATION

Cat Creek Pump Storage Hydro Budget Estimate

					Cost Allocations.			
					Generation / Pump Storage		Irrigation / Municipal Water	
Total Costs Estimate					%	$	%	$
1) Upper Reservoir				419,150,000	20%	83,830,000	80%	335,320,000
2) Intake				17,740,000	95%	16,853,000	5%	887,000
3) Penstock				141,135,000	95%	134,078,250	5%	7,056,750
4) Powerhouse				428,000,000	95%	406,600,000	5%	21,400,000
5) Substation				31,600,000	95%	30,020,000	5%	1,580,000
6) Transmission Line				28,500,000	95%	27,075,000	5%	1,425,000
7) Interconnection								
Subtotal				1,066,125,000	66%	698,456,250	34%	367,668,750
8) Miscellaneous				240,282,500	95%	228,268,375	5%	12,014,125
Total Estimate				**1,306,407,500**	**71%**	**926,724,625**	**29%**	**379,682,875**
Uses	-							
Category Amount								
Hard Costs				1,306,407,500	71%	926,724,625	29%	379,682,875
I DC, Soft Costs				271,500,000	71%	192,593,609	29%	78,906,391
Total Uses				1,577,907,500		1,119,318,234		458,589,266
Sales Tax	ID ST ST	6%		0	71%	0	29%	0
Total w IDSTX				1,577,907,500		1,119,318,234		458,589,266
Pre Const Interest (% / Yrs.)		3.7	5	116,273,219		82,480,585		33,792,634
Installed Cost				1,694,180,719	**71%**	1,201,798,820	**29%**	492,381,899

The cost allocation presented here is done for the purpose of helping clarify the financial challenge facing the PSH. Since, at 100,000 acre-feet capacity, the upper reservoir is about five times the volume reserved for PSH, this analysis allocated 80 percent of the reservoir cost to the irrigation portion of the project.[1]

The other project categories deal almost exclusively with the operation of the PSH portion of the project. While these items may also be used to move water to and from the reservoir for irrigation purposes the vast majority of the time their use will be in service of the PSH's daily operations. On an annual basis, water being moved through the system in support of the PSH may approach 14,600,000 acre-feet.[2] The water being moved through the system in support of

[1] Notice of Amended Rule 40.05 Disclosure, June, 16, 2020, p. 4.
[2] 20,000 Acre-Feet down, plus 20,000 acre-feet up, times 365 days per year = 14,600,000 Acre-Feet.

the irrigation portion on an annual basis is projected to only be at most about 100,000 acre feet, less than one percent of the amount used for the PSH.[3] This analysis, conservatively vis a vis the PSH portion of the project, chose 5% as the allocation for the non-reservoir items.

This model allocated 29% of the cost of the reservoir and other shared project costs to irrigation and other consumptive uses, leaving the PSH to only have to support the debt service on 71% of the total project cost. That allocation, combined with the assumption that the irritation portion breaks even financially, reduces the revenue requirement necessary to service the debt load on the PSH portion of the project model.

[3] 100,000 up, plus 100,000 down every two years. (100,000 +100,000) / 2 = 100,000 Acre-Feet.

APPENDIX III - CAISO NP15, DAY AHEAD, HOURLY, LOCATIONAL MARGINAL PRICES, 2009 - 19

Ten Highest Priced Hours per Year, 2009 – 2019, ($/MWH)
CAISO – NP15, Day Ahead Market [4]

High Side

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Avg.
											38.0		38.6		38.4	40.3	45.8	41.5	42.1	41.0	39.9	40.6		40.6
											39.2		39.0	40.1	41.7	42.8	42.9	43.3	42.6	42.4	39.2			41.3
											34.6		34.9	35.1	36.4	37.0	39.3	40.1	40.1	40.2	34.6			37.2
												29.9	30.6	32.0	34.5	37.7	38.3	37.1	35.7	34.1	30.8			34.1
												41.4	41.9	42.5	43.5	46.5	48.6	49.0	49.1	47.3	44.4			45.4
							47.5							47.1	49.3	53.2	60.1	60.7	59.2	56.8	52.4	47.9		53.4
						32.9	33.3								33.3	37.3	41.6	44.4	43.0	40.8	36.5	32.6		37.6
						30.2	30.5								28.5	32.4	38.8	43.0	43.3	40.1	33.6	29.6		35.0
					31.0	37.8	36.3									38.3	51.1	65.3	65.9	52.1	41.6	34.8		45.4
					36.4	42.3	38.5									41.8	53.2	65.7	70.4	59.4	47.7	39.6		49.5
					37.0	43.1	38.0									35.3	47.9	57.4	61.2	52.5	44.9	38.4		45.6
																								42.3

Twelve Lowest Priced Hours per Year, 2009 – 2019, ($/MWH)
CAISO – NP15, Day Ahead Market

Hour of Day

Low Side

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Avg.
2009	32.4	26.8	23.5	22.3	23.8	27.4	31.6	33.9	34.6	36.0			37.2											32.1	30.1
2010	30.5	27.6	25.0	24.0	25.6	29.7	31.1	33.4	35.3	37.1													36.4	32.3	30.7
2011	21.6	18.1	14.6	13.3	15.8	20.6	25.4	30.9	31.4	32.2													31.2	25.0	23.3
2012	23.1	21.3	18.8	18.3	18.9	21.8	24.4	26.7	26.9	27.9													27.7	24.4	23.3
2013	35.7	33.8	31.8	31.7	32.2	34.9	38.5	40.7	39.8	40.1													40.9	37.7	36.5
2014	41.1	38.2	35.5	34.7	36.0	40.6	45.4		44.9	44.4	45.0	45.3												43.9	41.2
2015	27.7	26.6	25.7	25.3	26.4	29.6				29.6	29.6	30.0	30.0	30.5										29.9	28.4
2016	24.3	23.0	22.3	21.9	23.0				26.0	24.3	24.1	24.5	24.6	24.9	26.0										24.1
2017	26.8	24.7	23.5	23.4	25.3				27.3	23.2	22.4	22.3	22.3	23.8	26.3										24.3
2018	33.3	31.1	29.6	29.3	31.1				30.7	27.8	26.9	26.5	26.3	27.4	29.7										29.1
2019		31.2	29.9	29.8	31.7				29.7	26.1	24.5	24.0	23.9	25.1	26.7	30.1									27.7
																									29.0

[4] CAISO maintains the largest public listing of wholesale energy trading information west of the Rocky Mountains. NP15 (aka Northern California, California-Oregon Border, COB) is one of the two trading hubs most frequently used by NW utilities, the other being MIDC (aka Mid Columbia). This analysis uses the CAISO numbers because they are publicly reported and have the advantage of being from a bigger market, thus assuring that enough power is traded on a daily basis to absorb the production of a facility like CCE's PSH. Finally, this analysis uses prices from the Day Ahead Market, meaning that the prices presented here are for firm power. That also tends to mean that the prices are slightly higher ($2-$3/MWh) and more consistent, less variable, than spot market prices.

APPENDIX IV - NW WHOLESALE ENERGY PRICE HISTORY

The challenge for any independent PSH developer is to build and operate in an area where market prices exhibit the combination of peak prices and daily price differences between peak price hours and low price hours sufficient to pay for its project.

For CCE's proposed PSH, the absolute price floor is $20.4/MWh, the minimum price necessary to cover annual debt/dividend service requirements even if power for pumping water into the upper reservoir is free of charge. *See* line 25 in Appendix I. There are a couple problems with that $20.4/MWh number. The first is that, as Chart 1, below, indicates, selling power for $20.4/MWh or higher on the western grid is not a sure thing. The average high load hour (HLH) price on the MID-C trading hub for the last four years was only $23.50, only $3.1 above the CCE price floor. (Again, $20.4 does not include wages, M&O, etc.) Marcus Harris of the Bonneville Power Administration confirmed the issue in an email earlier this year. BPA sells about 25% of its power on the MID-C hub which, over the past five years, has only averaged $19/MWh.[5]

The NP15 DAM looks like a more lucrative market for CCE in that it shows HLH prices for the past decade as high as $50/MWh and average HLH prices for the last year at $34/MWh. Those prices are high enough to cover the CCE PSH's absolute price floor, but that brings up problem number two: Power to refill the reservoir is not free.

The best, indeed the only, public reporting of off-peak prices related to the northwest is for the CAISO/OASIS NP15 trading hub. It shows HLH prices for the past 11 years as being $38/MWh and Low Load Hour (LLH) prices as being $29/NWh, a difference of only $9/MWh. Worse for CCE is that, as solar and wind provide ever larger portions of the daily energy supply west of the Rocky Mountains, both HLH prices and the spread between HLH and LLH prices are declining, the exact opposite of what CCE needs to profitably run the PSH. For the past year, the price spread between HLH ($34/MWh) and LLH ($28/MWh) was only $6/MWh.

[5] Marcus Harris, Budget Officer and Manager of Financial Planning & Analysis, Bonneville Power Administration, maharris@bpa.gov, email, Nov 22, 2019, at 1:59 PM.

The numbers in previous paragraphs are averages. It is possible, by carefully selecting a subset of the HLH or LLH time ranges, to arrive at sales prices and purchase prices higher and lower, respectively, than the raw averages suggest. That becomes more difficult as the two time series converge, but it is still possible. That is the process by which the numbers in the previous section, Appendix III, were derived. By selecting the highest priced 10 hours, each year, for the previous 11 years, this analysis calculates that CCE could have sold its PSH power for an average of $42.3/MWh. Similarly, by selecting the lowest priced 12 hours, each year, for the previous 11 years, this analysis calculates that CCE could have filled the upper reservoir for $29/MWh[6], a difference of $13.3/MWh. But, even that is not enough to cover CCE's proposed PSH debt. To be profitable while selling power for $42.3/MWh, CCE's PSH needs to be able to buy power for at prices down around $16.2/MWh, a difference of about $26/MWh.

For CCE's PSH application to make financial sense, CCE needs to make a convincing argument that peak prices and accompanying HLH vs LLH price differences are going to: A.- Occur; B.- Occur Soon, within about 5 years; and C.- Persist for 30+ years, although the history of prices on West Coast energy markets for the past decade has been going the opposite direction.   There is absolutely no evidence that that combination of events will ever occur.

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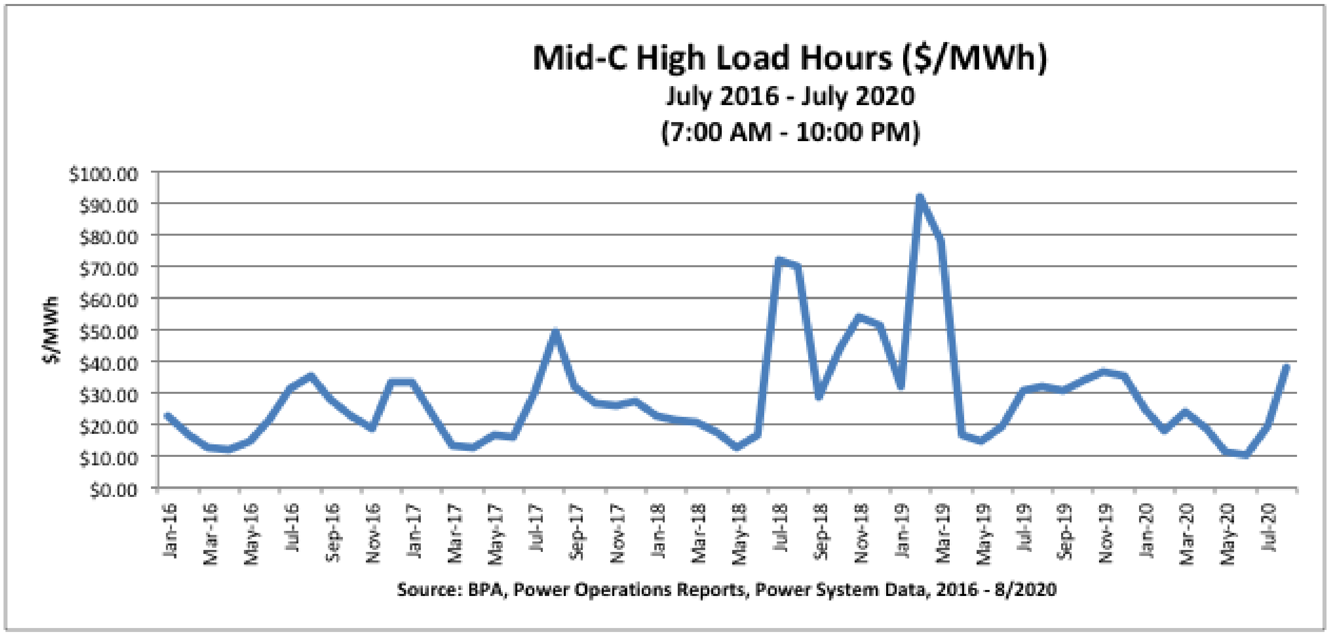
[6] The traditional HLH and LLH definitions don't always apply well to PSH projects. LLH is usually defined as the 8 hours from 10:00 pm to 6:00 am. However, to refill the reservoir after generating for 10 hours, CCE will need to be in pumping mode for nearly 12 hours. In that manner the pumping operation will spill over into traditionally higher priced high load hours and the resulting prices the project sees may not be as low as the traditional LLH averages suggest.

Chart 1. MID-C High Load Hours as Reported by Bonneville Power Administration. Average Four Year Price = $23.50 / MWh.



Mid-C is one of the two main markets for CCE's PSH energy, the other being NP15. MID-C is generally a lower priced market, a result of the substantial amounts of low marginal cost hydropower sold at MID-C. The problem for a firm trying to arbitrage MID-C energy is that lower peak prices leave less potential room for daily price differences. The average high load hour price for the past four years was $23.5/MWh. If CCE were to sell its power for $23.5/MWh it would fail to operate profitably even if the power necessary to refill the upper reservoir was less than about $3/MWh, an amount that has no chance of occurring.

Chart 2. Peak Hour, Off-Peak Hour, and Daily Average, CAISO, NP15 Prices.

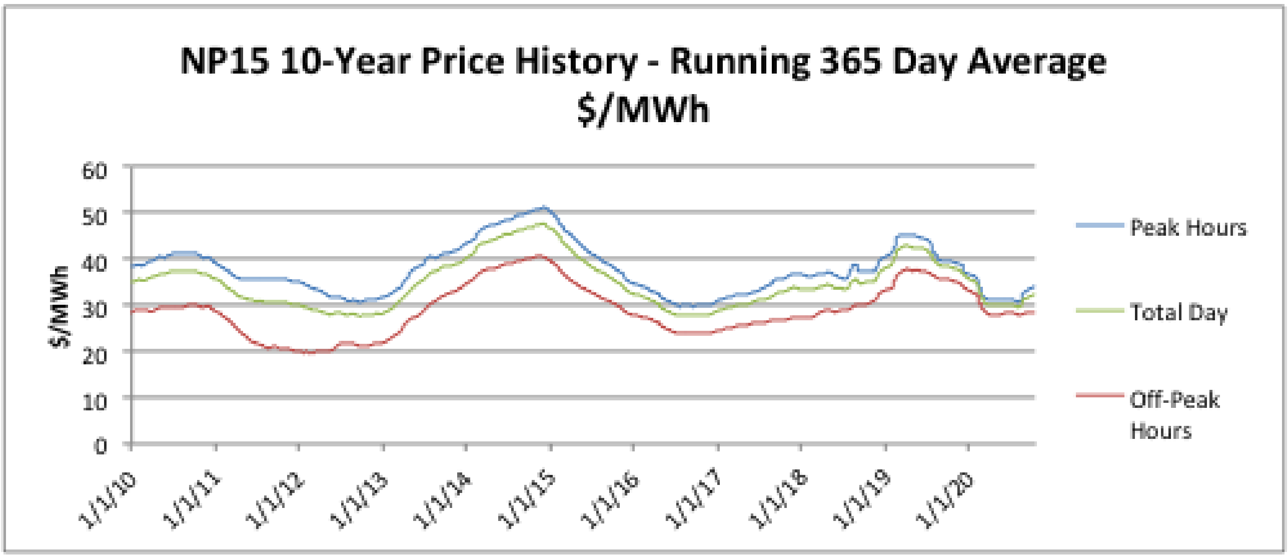


Chart 2, above shows the price history of the NP15 Day wholesale energy market for the past decade. Peak hour prices have been as high as $50/MWh for an entire year, but the average for the decade is only $38/MWh. Perhaps more significant is that the average for peak hour prices for the most recent year are about $5/MWh lower than they were a decade ago. Also, these are nominal prices. They have not been adjusted to account for inflation. Had that operation been performed, prices for the last year would have been even lower relative to prices a decade ago.

Also, notice that the price difference between peak hours and off-peak hours was about $10/MWh for the first three years of the chart. However, beginning in about 2015 the two curves began to converge. In the most recent year, the difference between peak and off-peak prices was only $6/MWh.