BOTTERELL LAW CORPORATION

BARRISTERS & SOLICITORS
2324 Brethour Avenue
SIDNEY, BC V8L 2A3

250.655.7410

E-MAIL: RBOTTERELL@TELUS.NET

Via E-mail: Commission.Secretary@bcuc.com

October 18th, 2017

Mr. Patrick Wruck
Commission Secretary
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Commission Secretary Patrick Wruck,

Re: British Columbia Hydro and Power Authority – British Columbia Utilities Commission Inquiry Respecting Site C – Project No. 1598922 - Letter A-22 issued on October 11th, 2017

Along with Maegen Giltrow, Ratcliff & Company LLP, we are legal counsel for Peace Valley Landowner Association and Peace Valley Environment Association with respect to Mr. McCullough's submissions in these proceedings.

We hereby submit Mr. McCullough's comments with respect to the Commission's October 11th request A-22 for comments on the Alternative Portfolio.

We wish, however, to highlight a procedural and substantive issue that has arisen in these proceedings. As you know, we have previously expressed our concern over the lack of cross-examination in this proceeding, thereby leaving the risk of assertions by any party being left untested (F35-4). This risk materialized in the technical presentations held October 13 and 14, 2017.

Mr. McCullough has, three different times in this proceeding, provided evidence of Mid-C forward markets:

1) F35-5 September 13, 2017 (pp. 27-28 and Figures 17 & 18)
2) F35-7 September 24, 2017 (p. 2 Fig 1)
3) October 13, 2017 Transcript (T pp. 1223-1224 ll. 22-1; T p. 1232 lines 3-18)

This evidence is directly relevant to the question of what positive or negative value should be attributed to energy and capacity from Site C that is surplus to domestic needs.

BC Hydro directed a specific response to Mr. McCullough's submissions on load forecast dated October 11, 2017 (BC Hydro Submission on the British Columbia Utilities Commission Preliminary Report, Appendix C Response to Load Forecast Submissions of Robert McCullough). Despite this, BC Hydro said nothing in Appendix C to impugn the reliability or credibility of Mr. McCullough's evidence on future Mid-C markets. BC Hydro remained silent on this point. Had it provided a response, Mr.

McCullough would have been able to reply when he delivered his supplemental oral testimony on October 14, 2017. However, he did not have this opportunity.

Instead, it was not until BC Hydro's oral submission October 14, 2017—the final oral submission in the technical sessions, with no further opportunity to respond—that BC Hydro sought to respond on this point by seeking to impugn the reliability and credibility of Mr. McCullough's evidence about forward Mid-C markets. Mr. McCullough had no opportunity to respond, and therefore the Commission is left with two starkly opposed assertions of fact. With respect, this is just the sort of circumstance that cross-examination, or even the abbreviated interrogatory process we had previously requested (F35-4), would have avoided.

Had BC Hydro had the opportunity to cross-examine Mr. McCullough on this point, the Commission would have been able to hear the basis for Mr. McCullough's evidence and would, in our submission, have been satisfied of the credibility and reliability of Mr. McCullough's evidence. As it stands, we are left to point to this evidence in written form in the enclosed comments on A-22 to which, fortunately, the evidence is relevant. Were it not for the opportunity afforded by the Commission's call for comments on A-22, this issue would have been left in a most unsatisfactory and unresolved state.

Furthermore, while the Panel now has the evidence in front of it to satisfy itself of the credibility and reliability of Mr. McCullough's evidence, such is not the case for those who listened to the proceedings on October 14th and have not read the attached submission. In the circumstances, it would be appropriate for the Panel to expressly correct the record in it final report.

Had we had the opportunity to cross-examine BC Hydro's representative about the counter-proposition, we would have had the opportunity to ask:

- On what basis is BC Hydro deriving its forecast surplus capacity value (in light especially of the fact that in the 2013 IRP, BC Hydro itself determined it appropriate to attribute no value to future capacity surplus);

- On what basis does BC Hydro speculate that a market may be emerging that would glean higher than average market prices for surplus Site C capacity in light especially of

  (a) Appendix S to BC Hydro's August 30 2017 F1-1 submission, which is entirely qualitative with no demonstrated analysis of value; and

  (b) evidence brought forward by Mr. McCullough that:

  > "In the Northwest power pool where we live, it was so surplus on capacity for now into the foreseeable future, you can't sell capacity. I checked whether Powerex had sold any capacity on the west coast, and it was minuscule. And that's going to continue for quite a while, according to the authoritative materials from the North American Electric Reliability Council, who have the legal responsibility for maintaining that." (October 13 T p 1228 lines 15-23)

Accordingly, we direct the Commission's attention to Mr. McCullough's comments on A-22, wherein he has sought to address these outstanding issues to the extent possible within the format allowed at this stage of the proceeding.

Yours truly,

BOTTERELL LAW CORPORATION

ROBERT H. BOTTERELL

Cc: Client, McCullough Research, Maegen Giltrow, Ratcliff & Company LLP

McCullough Research

Robert F. McCullough, Jr.
Principal

Date: October 18, 2017

To: British Columbia Utilities Commission

From: Robert McCullough

Subject: Comments on Commission Alternative Resource Portfolios

Introduction

On October 11, 2017, the British Columbia Utilities Commission generated three very viable alternative scenarios to the construction of Site C. I recommend that the Commission adopt these scenarios although they may be a bit conservative in several areas which we address below.

The August 2, 2017 Order in Council mandated this step:

> 3(b)(iv) Given the energy objectives set out in the *Clean Energy Act*, what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C project?[1]

Throughout this proceeding we have limited our comments to areas where we might bring a comparative advantage to the deliberations. We are following this practice in this submission, specifically addressing two issues:

1. Firming, shaping, and storage; and,
2. Economics of sales and purchases in the market of which British Columbia Hydro is a small part.

We will also address British Columbia Hydro's comments on these scenarios, presented orally on October 14, 2017.[2]

[1] Order of the Lieutenant Governor in Council Number 244, August 2, 2017, pages 2 and 3.
[2] Site C Inquiry: Presentation to Commission Panel Chris O'Riley, Randy Reimann, Tom Bechard, Andrew Watson, and Mike Savidant, October 14, 2017, page 27.

6123 Reed College Place • Portland • Oregon • 97202 • 503-777-4616 • Robert@MResearch.com

Summary and Conclusion

In light of the direction given at s. 3(b)(iv) of the Order-in-Council directing this inquiry, the assessment of alternatives is only relevant in the context of comparison to the unit energy cost of Site C. Based on our assessment, the alternative portfolio put forward by the Commission is reasonable and defensible, if conservative, and compares favorably as against Site C. As we set out below, there are further measures that may be considered to increase the favorability of the base alternative portfolio as against Site C.

Comparison of Alternatives:				
		Commission Scenarios		
	Site C	**Low LF**	**Medium LF**	**High LF**
Original Cost	$ 8,775			
Plus, Cost Overrun	$ 610			
Minus Sunk Costs	$ (2,100)			
Cost of Continuation	$ 7,285	$ 1,851	$ 2,889	$ 3,441
Termination Cost		$ 1,200	$ 1,200	$ 1,200
Actual Cost	$ 7,285	$ 3,051	$ 4,089	$ 4,641
Termination Advantage		$ 4,234	$ 3,196	$ 2,644

Our response demonstrates, contrary to BC Hydro's submission, that the October 11th portfolio:

- Is less expensive than a portfolio with Site C, even considering sunk and termination costs
- includes resources that are commercially feasible, and
- does provide superior firming, shaping and storage capability as Site C to meet forecast need.

Firming, Shaping, and Storage:

Background

British Columbia Hydro has commented on the significant benefits of Site C's reservoir on many occasions in this proceeding. Their definition of these services can be found early in their initial submission:

- "Firming capability is the ability of resources to quickly change output in response to changes in customer demand and output from variable generation resources that fluctuate within the hour (e.g., wind or solar). The best resource for this capability is large hydro, but it can also be also [*sic*] supplied by pumped storage and gas-fired generation. Variable resources like wind, solar and run-of-river hydro, the output of which depends on environmental factors, do not have this capability;

- Shaping capability is the ability of resources to reduce their generation supply within the day to allow the electricity system to absorb variable resource electricity (e.g., wind, run of river, solar) when our customers do not need it and then to release that energy later in the day when it is required. Large hydro and pumped storage have this ability and other storage methods are being developed such as batteries or compressed air; and

- Storage capability is the ability of resources to adjust their generation supply at certain periods within the year to respond to seasonal changes in variable generation resources (e.g., run-of river hydro output is highest during the spring freshet and lower in the late summer). Only large hydro resources have the capability to store electricity seasonally."[3]

It should be noted that Site C does not meet all three of these definitions which a further quotation from British Columbia Hydro's Appendix F to the initial submission makes clear:

> The Project reservoir, with a normal operating range of 1.8 m and an active storage volume of 0.4 per cent of the active storage volume of Williston Reservoir, <u>does not have sufficient storage volumes to provide seasonal shaping of generation</u>.[4] (emphasis added)

The Commission's proposed scenarios use batteries to meet this requirement. Given British Columbia Hydro's definitions above, this is an appropriate choice. It is not the only choice, however. Nor is it a particularly inexpensive choice when British Columbia Hydro already has a surplus of resources designed to meet these three storage standards.

There have been many mentions of the Canadian Entitlement under the Columbia River Treaty in this proceeding. British Columbia Hydro rejects the Canadian Entitlement for a

[3] BC Hydro Submission to the British Columbia Utilities Commission Inquiry into the Site C Clean Energy Project, British Columbia Hydro, August 30, 2017, Page 42.
[4] Ibid., Appendix F, page 2.

variety of reasons as a source for energy and capacity other than "for a short-term bridging or contingency resource."[5]

Perhaps because the subjects of the Columbia River Treaty and the Canadian Entitlement are so challenging, British Columbia Hydro's discussion neglected to address the surplus resources on their own system – specifically those currently addressed by the Columbia River Non-Treaty Storage Agreement.[6]

This agreement covers considerably more firming, shaping, and storage than Site C and has been valued at US$8 million per year.[7,8]

The context for the Non-Treaty Storage is, of course, the Columbia River Treaty. The Treaty is currently in the early stages of renegotiation. Outside of the negotiators at British Columbia Hydro, the Bonneville Power Administration, and the U.S. Army Corps of Engineers, few understand its complex mechanics and financial implications. Below, the history and the operations of the treaty will be briefly addressed.

The geography of the Northwest Power Pool includes massive hydroelectric potential provided by the U.S. and Canadian Rocky Mountains. The headwaters of the Columbia River extend into British Columbia and then cross Washington State until emptying into the Pacific near Astoria, Oregon. The Columbia Gorge provides many excellent locations for hydroelectric dams since the river passes through a relatively narrow canyon. Although this is excellent for dams and generators, it is not ideal for storage. The storage opportunities are on the Canadian side of the border.

[5] Ibid., page 48.
[6] Contract No. 12PG-10002 COLUMBIA RIVER NON-TREATY STORAGE AGREEMENT executed by the BONNEVILLE POWER ADMINISTRATION and BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, April 10, 2012.
[7] ADMINISTRATOR'S DECISION RECORD NON-TREATY STORAGE AGREEMENT WITH BC HYDRO, Bonneville Power Administration, March 23, 2012, page 6.
[8] BPA's valuation occurred five years ago when energy prices were higher than they are today. The total agreement would be valued at least 20% less in today's markets. The non-treating storage is considerably larger than Site C's. The contract covers 1.5 million-acre feet (MAF) with an option for an additional 1 MAF. Site C is 4/10ths of 1% of Williston's 40 MAF or .16 MAF.

Figure 1: Map of dams along the Columbia river.[9]

British Columbia's negotiators have provided an excellent discussion of the system:

> The Columbia River in Canada has three dams in series – Mica, Revelstoke, and Hugh Keenleyside. The upstream most project – Mica – is the largest storage on the whole Columbia system with 12 MAF of active storage. It

[9] Columbia River Treaty 2014/2024 Review, U.S. Entity, April 2013, page 2.

> should be noted that Revelstoke Dam is not a Treaty dam and is operated for daily/weekly shaping.
>
> Mica and Revelstoke will have a combined generating capacity of approximately 5,700 megawatts (MW) by 2024, or 50% of BC Hydro's generating capacity, and are critical in reliably meeting British Columbia domestic load. Hugh Keenleyside Dam is the third project in the series. It is a low head dam and despite being the third largest reservoir in British Columbia with 7 MAF of active storage, it has relatively little power generation. The primary purpose of this dam was to provide flood control and power benefits to the U.S. under the Treaty. In 2002, the 185 MW Arrow Lakes Generating Station was installed adjacent to the dam.
>
> Duncan Dam (1.4 MAF) on the Kootenay River is the third Canadian Treaty dam and does not currently have any power generating capability.[10]

The basic logic of the treaty was to tie the operations of storage in British Columbia to the generation in Idaho, Montana, Oregon and Washington.

This was a very prudent solution to the extreme variability of flows along the Columbia River. Unlike many other hydroelectric systems, the Columbia River's annual flows can vary dramatically. Without extensive storage, the firm generation along the Columbia would be significantly diminished. The total generation might be roughly the same, but the amount of dependable generation would be considerably less.

The treaty also created the "Canadian Entitlement", which compensates British Columbia for the use of their reservoirs:

> This delivery [of the Canadian Entitlement] ranges from 1,176 to 1,369 megawatts (MW) of capacity and 465 to 567 annual average megawatts (aMW) of energy.[11]

The U.S. Entity has a variety of materials available on the treaty and its benefits:

> Before the Columbia River Treaty, high springtime flows on the Columbia River frequently overwhelmed the ability of the United States' downstream infrastructure to generate power and manage flood risk. The four dams built under the terms of the 1964 Columbia River Treaty (three in Canada and a

[10] U.S. Benefits from the Columbia River Treaty – Past, Present and Future: A Province of British Columbia Perspective BC Ministry of Energy and Mines, June 25, 2013. Page 8.
[11] Canadian Entitlement, U.S. Entity, April 2013, page 2.

> fourth in Montana) approximately doubled the water storage capacity on the Columbia River system. The Treaty and Treaty dams enhanced the cooperation between the U.S. and Canada, helping to ensure mutually advantageous operation of the dams by improving the ability to regulate the timing of streamflows by capturing high spring flows and releasing this water more gradually over the summer, fall and winter months. Overall, the coordinated storage and regulation of flows between the United States and Canada vastly improved both hydropower production and flood mitigation in the Columbia Basin.
>
> The increased power generation in the United States resulting from the operation of additional storage capacity created by the three Treaty dams built in Canada is referred to as the downstream power benefits. The Treaty negotiators in the early 1960s agreed that the United States and Canada would equally share these benefits, which are calculated annually according to a complex method negotiated among the Treaty's authors. It is essentially a theoretical value placed on the additional generation. Canada's half of these calculated downstream power benefits is called the Canadian Entitlement.[12]

British Columbia's three dams provide more storage than is covered by the treaty:

> Coordination of the Pacific Northwest and BC Hydro systems began in 1964 with ratification of the Columbia River Treaty (Treaty). Under the Treaty, Canada was required to construct and operate 15.5 million acre-feet (MAF) of storage in Canada at Mica, Arrow, and Duncan projects. The United States was allowed to construct 5 MAF of storage at Libby Dam. BC Hydro designed and built Mica dam to store more water than the 7 MAF required under the Treaty. As a result, an additional 5 MAF of usable storage is available at Mica.
>
> This extra storage is referred to as non-Treaty storage and is not operated under the terms of the Treaty. The Treaty limits use of non-Treaty storage to actions that do not reduce Treaty flood control and power benefits. Within that constraint, BC Hydro has used the storage space for its benefit by redistributing water among its reservoirs. BPA access to this storage is obtained only through negotiation of operational agreements that provide mutual benefits to the BPA and BC Hydro. Absent an agreement, the benefits

[12] What is the Canadian Entitlement and how did it come to be? Columbia River Treaty 2014/2024 Review, United States Entity, April 2013, page1.

> of releasing water from Arrow across the Canada-U.S. border cannot be achieved. [13]

Non-Treaty Storage at the Mica Dam is a less costly alternative to battery storage

To describe the Non-Treaty Storage Agreement very concisely, British Columbia built more storage at Mica than is required by the treaty and has rented this storage to the Bonneville Power Administration (BPA) for the past fifty years under a series of agreements that are due to expire in 2024.

BC Hydro has rented 1.5 MAF (million-acre feet) of storage capacity with an option for another 1 MAF to the Bonneville Power Authority (BPA). This agreement is due to expire in 2024.

Instead of renewing this agreement, BC Hydro could choose to use this Mica storage capacity in addition to or as a replacement for battery storage in the alternative portfolio.

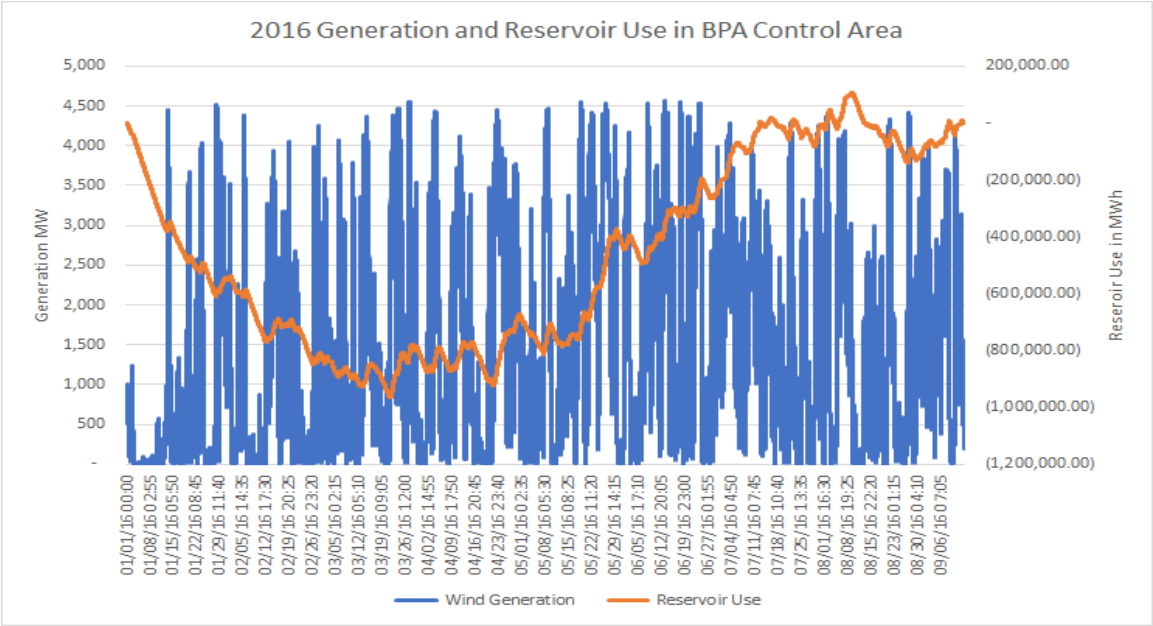
Assuming that BPA's share of the non-treaty storage was purchased at BPA's valuation (adjusted for the falling value between 2012 and 2017) and calculated according to the methodology in the Commission's spreadsheet, the cost of this much larger resource would only be $125 million compared to the Commission's cost of batteries of $146 million.

We estimate that 1 MAF of Mica storage capacity will firm 4,782 MW of wind over one year. This is more than enough to back up the 444-685 MW of wind included in the alternative portfolio. Our analysis is set out below.

It is a reasonable assumption that the wind farms in the Commission's scenarios will operate roughly comparably to wind farms across the border in Oregon and Washington.

Bonneville Power Authority provides data on wind generation in five-minute increments. For 2016, we can see how many megawatt-hours it would take to firm the 4,782 MW of wind in their control area over one year. The following chart shows the actual wind generation for twelve time increments in each hour. Charted in orange is the draw on the region's reservoirs.

[13] ADMINISTRATOR'S DECISION RECORD NON-TREATY STORAGE AGREEMENT WITH BC HYDRO, Bonneville Power Administration, March 23, 2012, page 1.



The maximum draw on the reservoirs comes at 6:45 P.M. on March 21, 2016. At that point, if the system wanted to maintain a minimum generation level of 1,414 MW from wind, the reservoirs would have been tapped for 986,235 megawatt-hours. After that date, the reservoirs would gradually refill.

In terms of Mica's storage, this is roughly equivalent to 1 MAF.

I have attached both the Non-Treaty Storage Agreement and BPA's Record of Decision to this submission.

Economics of sales and purchases in the market

The Commission's assumptions in A-22 placed the value of exported capacity at zero and the value of energy at Can$25/MWh. These are prudent values given the current market and reasonable market forecasts.

We note this is also consistent with BC Hydro's own approach in its 2013 IRP, where it determined it was not appropriate to assign any surplus value to capacity:

> **Note that BC Hydro has conservatively not assigned any value to surplus capacity**. In the recent John Hart Generating Station Replacement Project CPCN proceeding, BC Hydro provided evidence that while the market **value of capacity is uncertain because of illiquidity in the current Western Electricity Coordinating Council (WECC) region,** BC Hydro

> estimated a range of market values of categories of about $75/kW-year to $110/KW-year, based on recent Bonneville Power Administration (BPA) tariffs, transaction and market analysis. BC Hydro further estimates that U.S. market access transmission constraints could reduce the market value of capacity to $37/kW-year for the low end of the market range. These benefits associated with capacity surplus from Site C would add to its cost advantage described above.[14]

This is in stark contrast to the revised and speculative approach BC Hydro has taken to future capacity value in the present proceeding (F1-1 p. 64 and Appendix S), as we discuss below.

Forecasting the future is difficult and imprecise. The assumption that British Columbia Hydro can sell energy and capacity above the market[15] is, at best, speculative. In previous submissions[16] we have pointed out that existing transactions in forward market at Mid-Columbia are significantly less than British Columbia Hydro's undocumented forecasts. With a rapidly declining market in energy across North America, it is likely that British Columbia's forecast is dated.

On October 14, 2017, Mr. Bechard presented a rebuttal to the use of actual forward prices in his oral presentation.[17] He misspoke on a number of points.

First, he questioned whether the forward markets at Mid-Columbia are liquid through 2025. This is a fair concern. Forward markets, by their very nature, are more liquid in early years than later years. More parties are interested in the immediate future than periods further on the horizon.

This same argument was raised in the context of LNG future markets in F1-12 Appendix C and disproved in my remarks on October 14, 2017.[18]

In this case, Mr. Bechard went beyond questioning the depth of the market after 2022, he denied that there were any transactions that had ever occurred after 2022.[19] In doing so, he misspoke. The InterContinental Exchange [ICE] has a number of forward markets in energy. The data I have cited comes from the daily reports provided by the exchange. If

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[14] BCH 2013 IRP, November 2013, pages 6-43.
[15] F1-1 p. 103 and Appendix S
[16] F35-5 and September 13, 2017, pp. 27, 28 Figures 17 & 18 and F 35-7, September 24, 2017, p. 2 Fig 1
[17] Technical Input Proceedings Vancouver, Volume 12, Allwest Reporting, October 14, 2017, pages 1656 through 1658.
[18] Critical Review of British Columbia Hydro Appendix C, Robert McCullough, October 13, 2017, page 10.
[19] Technical presentation transcript, October 14, T p. 1657 l. 8-17

Mr. Bechard had checked, he would have found that there are open interests through to December 2025.[20,21]

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE				SETTLE		VOLUME AND OI TOTALS						
		OPEN#	HIGH	LOW	CLOSE#	PRICE	CHANGE	TOTAL VOLUME	OI	CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
MDC-Mid-Columbia Day-Ahead Peak Fixed Price Future - Mid Columbia														
MDC	MAY-24					25.00	.00	0	25	0	0	0	0	0
MDC	JUN-24					25.35	.00	0	25	0	0	0	0	0
MDC	JUL-24					34.45	.00	0	25	0	0	0	0	0
MDC	AUG-24					39.20	-.05	0	25	0	0	0	0	0
MDC	SEP-24					34.90	.00	0	25	0	0	0	0	0
MDC	OCT-24					30.55	.00	0	25	0	0	0	0	0
MDC	NOV-24					33.50	.00	0	25	0	0	0	0	0
MDC	DEC-24					40.55	-.05	0	25	0	0	0	0	0
MDC	JAN-25					40.75	-.05	0	25	0	0	0	0	0
MDC	FEB-25					34.70	.00	0	25	0	0	0	0	0
MDC	MAR-25					28.45	.00	0	25	0	0	0	0	0
MDC	APR-25					27.55	.00	0	25	0	0	0	0	0
MDC	MAY-25					26.20	.00	0	25	0	0	0	0	0
MDC	JUN-25					26.50	.00	0	25	0	0	0	0	0
MDC	JUL-25					35.65	.00	0	25	0	0	0	0	0
MDC	AUG-25					40.45	.00	0	25	0	0	0	0	0
MDC	SEP-25					36.10	.00	0	25	0	0	0	0	0
MDC	OCT-25					31.70	.00	0	25	0	0	0	0	0

Figure 2: Screenshot of CME's energy market report showing open interest for Mid-C going out to 2025.

Several other of his comments also appear to be misstatements. He explained that British Columbia Hydro has been "20 to 25 percent of the spot trades that occur at mid-C every day."[22] According to the Federal Energy Regulatory Commissions mandatory data on energy transactions, Powerex is less than 2% of transactions at the Mid-Columbia hub in 2016.[23,24]

Mr. Bechard then goes on to state:

> So, you know, I think it's incorrect to say that you can plot a forward curve out to 2026 based on actual traits [*sic*]. I don't think you can do that. I do think that ICE has some marks for those. I'm not sure where ICE gets those

[20] ICE. "End of the Day Report," October 12, 2017, p.1078.

[21] Open Interests are forward contracts currently in force. An open interest can be extinguished by offset – selling the contract -- or performance.

[22] Technical Input Proceedings Vancouver, Volume 12, Allwest Reporting, October 14, 2017, pages 1656 through 1656, lines 17 and 18.

[23] https://eqrreportviewer.ferc.gov/

[24] See Appendix A for detailed answer to the conflicting evidence between Mr. McCullough and Mr. Bechard on this point.

> marks from. I suspect it may be nothing more than an extension of the 2021-2022 prices.[25]

A forward curve is the set of future values for a commodity. Trading floors update their forward curves on the basis of actual trades every day at the close of the day shift.

A subsidiary of Standard & Poors, Platts, is a very significant information source in commodities markets. Traders, regulators, consultants, and ultimate large-scale consumers read many of their newsletters. One of Platts' many journals, Megawatt Daily publishes forward curves for hubs across the U.S. and Canada.

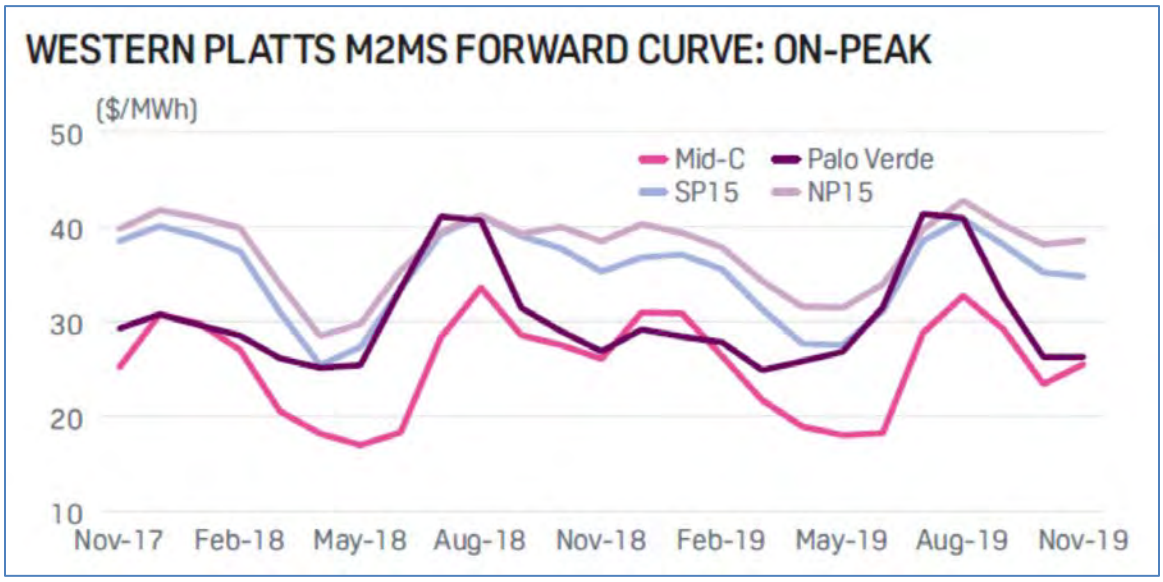

Figure 2: Megawatt Daily West Coast Forward Curves[26]

Platts uses ICE trading data and their own models to generate forward curves for a large variety of commodities and locations. It is the practice of significant journals like Platts to publish their methodology so that users of their data can judge the accuracy and honesty of their estimates.[27] Regulatory agencies like the Federal Energy Regulatory Commission have a continuing interest in this as well since a number of the Enron trading strategies involved falsifying market data.

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[25] Technical Input Proceedings Vancouver, Volume 12, Allwest Reporting, October 14, 2017, pages 1656 through 1657, lines 19 through 25.

[26] Megawatt Daily, Platts, October 18, 2017, page 14.

[27] METHODOLOGY AND SPECIFICATIONS GUIDE PLATTS-ICE FORWARD CURVE – ELECTRICITY (NORTH AMERICA), Platts, April 2015.

Platts issues a widely used set of forward curves every day. This product, M2MS, is a proprietary service, so was not available for us to provide in the Site C process. We have, however, relied on the prices in the forward markets that are close but not exactly the same, as set out below.

In submission F1-17, British Columbia Hydro has finally identified the source and date of their wholesale price forecasts at Mid-Columbia.[28] As expected, the forecasts relied upon so far in this proceeding are dated in 2015 and 2016.[29]

The following chart adds a thick red line to represent current forward prices on the same chart as prepared by British Columbia Hydro. As expected the prices diverge considerably – largely due to the use of vintage price forecasts:

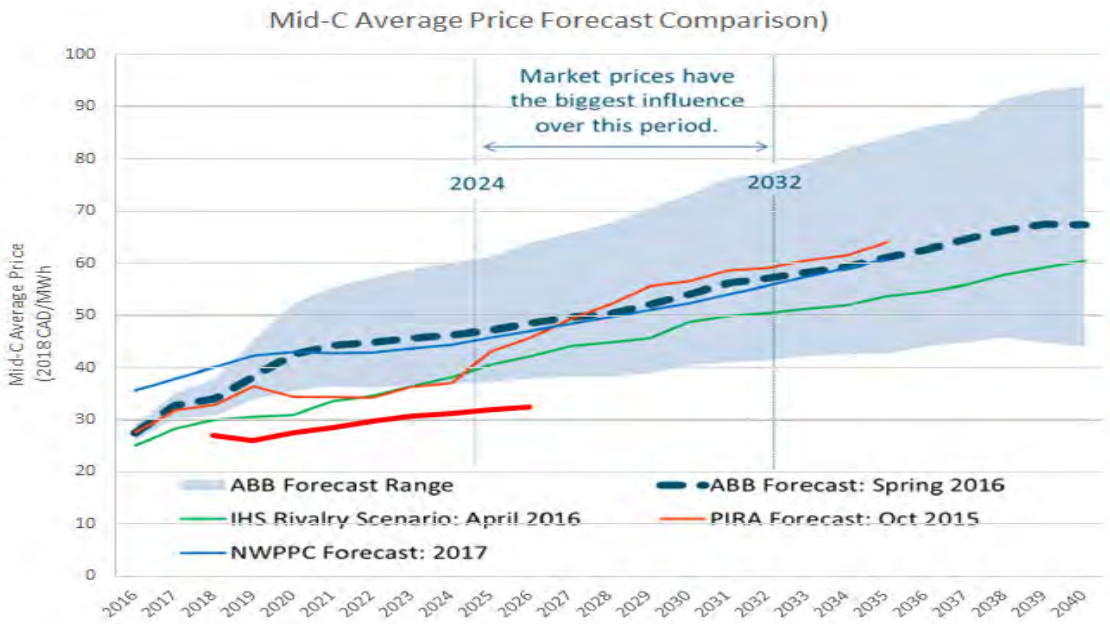

Figure 3: Depiction of forward curve from October 12th (bold red) and BCH price forecast.

[28] F1-17, October 18, 2017, page 23.

[29] The forecast identified as the NWPPC Forecast: 2017 is somewhat mysterious. It is not clearly available on the NWPPC web site.

Mr. Bechard also states:

> The other thing you can say about the forward curve is that it's not really valid to take a snapshot of the forward curve on a particular day and compare that to some market forecast that was done, you know, six months ago or a year ago. You could take a snapshot six months from now and it will look completely different than the snapshot today.[30]

This is somewhat true. Traders are Bayesians and update their opinions of the future with information they receive every day.[31] However, these forwards respond to the market conditions, and the market outlook six months ago are remarkably similar to the outlook today:

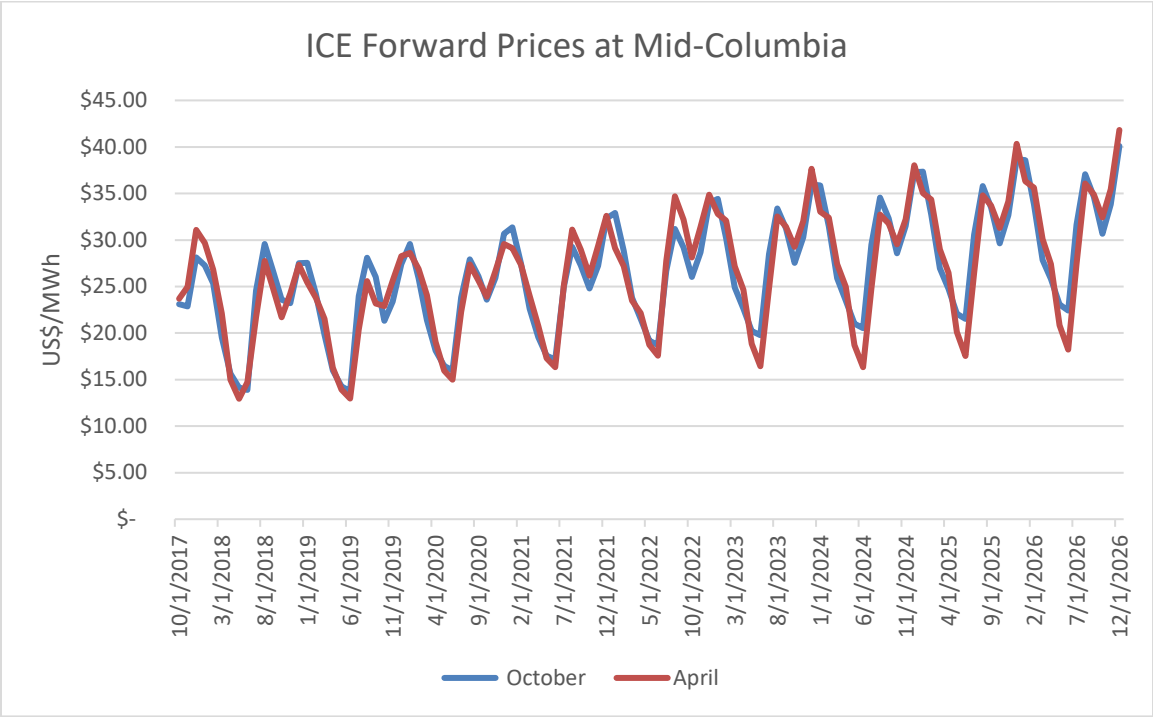

Figure 3: Comparison April and October ICE Forward Prices.[32]

[30] Technical Input Proceedings Vancouver, Volume 12, Allwest Reporting, October 14, 2017, pages 1656 through 1658, lines 1 through 7.

[31] Reverend Thomas Bayes (1601-1761) was the inventor of a statistical theory that now bears his name. In Bayesian statistics, estimates are updated with new data as opposed to classical statistics where a point estimate does not consider past and new data explicitly.

[32] CME forward prices for October 14th and May 24th.

As can be seen these forward prices are very comparable.

This dialog has largely focused on energy prices. The Commission spreadsheet also recommends that capacity prices be assumed to be zero for exports. There are good reasons to believe that capacity is not going demand high prices in the Northwest Power Pool in days to come.

NWPP: Case 1 – Existing/Class 1 Resources Winter	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Net Internal Demand	71,071	71,945	72,844	73,504	74,122	75,069	75,722	76,308	76,994	77,374
Anticipated Internal Capacity	88,752	89,866	90,412	90,470	90,753	91,065	91,475	91,471	90,634	90,575
Wind Expected On-Peak MW	3,006	3,515	3,865	3,867	3,869	3,870	3,872	3,881	3,882	3,884
Percentage of Capacity	21.5%	23.4%	22.5%	22.5%	22.5%	22.5%	22.5%	22.4%	22.4%	22.4%
Solar Expected On-Peak MW	0	0	0	0	0	0	0	0	0	0
Percentage of Capacity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro Expected On-Peak MW	34,358	34,379	34,400	34,488	34,382	34,386	34,392	35,385	35,838	35,841
Percentage of Capacity	65.1%	64.8%	64.6%	64.7%	64.5%	64.4%	64.4%	64.9%	65.1%	65.1%
Imports	6,760	6,700	6,800	6,766	7,517	8,188	8,598	8,694	8,966	9,419
Exports	1,700	0	0	0	0	0	0	100	993	1,161
Anticipated Resource Reserve Margin MW	5,812	5,906	5,403	4,690	4,252	3,459	3,107	2,419	782	279
Anticipated Resource Reserve Margin %	24.9%	24.9%	24.1%	23.1%	22.4%	21.3%	20.8%	19.9%	17.7%	17.1%

Figure 4: 2017-2026 NWPP Winter Reserve Margins[33]

The winter reserve margin is high by industry standards. The summer reserve margin is very high – so high that the ability to demand premiums in the California market will be diminished due to extensive competition.[34]

Despite appropriately attributing no value to capacity surplus in its 2013 IRP (2013 IRP p. 6-43 Nov 2013) because of inherent uncertainty arising from illiquidity, BC Hydro has now changed course, and attributes aspirational value to surplus capacity based on hoped for 'emerging opportunities". In its August 30 2017 F1-1 filing in the present proceeding at p.103 BC Hydro plainly asserts that BC Hydro anticipates obtaining above average prices from export markets for capacity and flexibility.

8.6 The Flexibility of Site C Can Obtain Above Average Prices from Export Markets

> The extensive lead time associated with new generation additions, and the challenges inherent in forecasting demand years into the future, give rise to the potential that new generation resources enter service in advance of actual need. This is a risk inherent in resource

[33] NWPP, "Northwest Power Pool Area Assessment of Reliability and Adequacy 2016-2017," October 17, 2016, page 12.
[34] NWPP, "Northwest Power Pool Area Assessment of Reliability and Adequacy 2016 Summer Operating Conditions," May 2, 2016.

> planning. As described in **Appendix S**, BC Hydro through its trading subsidiary Powerex would be able to optimize the trade benefits of any surplus. As a result it is likely that we would be able to sell any surplus on the energy spot market **for more than the Unit Energy Cost of completing the Project on the current schedule.** Two sensitivities were modelled with respect to recovery of costs in the spot electricity markets: (1) the benefit of capacity and flexibility; and, (2) the lower band of BC Hydro's market price forecast. The results show that there could be significant up-side to exporting surplus capacity and flexibility benefits associated with Site C. The benefits of completing Site C are still significant even in a scenario with low market prices for surplus exports.

However, a look at Appendix S does not provide any detail of this new analysis[35] Appendix S states, aspirationally and without evidence:

> "Specifically, in addition to any short -term surplus energy sales, there **may also be emerging opportunities** to sell surplus ***capacity and flexibility*** from the BC Hydro system supported by new flexibility and capacity from Site C. Together, sales of surplus energy, capacity and flexibility **may partially, or wholly**, offset the cost of Site C generation until its full capability is required to meet BC Hydro needs.
>
> The expected prices for short term energy sales from 2024 to 2030 are estimated by **ABB** to be around CAD$41/MWh. (p 1) However, as discussed in Appendix F, surplus energy sales supported by the addition of highly flexible resources, such as Site C, can be expected **to exceed prevailing average wholesale energy prices**, through sales in the higher priced hours of the year.[36]
>
> …
>
> In addition to potential emerging opportunities to sell capacity and flexibility in the Pacific Northwest and Alberta, **there is a rapidly emerging need** for ***flexibility*** and ***capacity*** products in California… **There is thus a growing potential** that surplus hydro capacity and flexibility could be monetized either through sales of new capacity and/or flexibility products in California's organized markets, or through a direct transaction with a California party.[37]

[35] And Appendix F, which is referred to in Appendix S, at F p 8 Table 1 shows that it is calculated based on Mid-C day ahead index, but only for 2014-2017; it provides no data about future prices for capacity.
[36] Ibid., page 1.
[37] Ibid., page 2.

> …
> Accordingly, the costs associated with the addition of ***capacity*** and ***flexibility*** rich resources, such as Site C, **may be partially or wholly offset**, until it is needed, through short -term energy sales and/or through longer-term market transactions that include capacity and/or flexibility commitments in western wholesale energy markets.
>
> **If the decision is made to proceed with completing Site C, BC Hydro would continue to closely monitor domestic needs** for the resource and Powerex would likewise continue to monitor the market opportunities for surplus flexible generation. If it becomes clear at some point that the Site C generation will not be fully required in 2024, and an opportunity arises to make a commitment in the external market that aligns with the expected surplus capability and expected timeframe of that surplus, Powerex **could seek to enter into sales that maximize the value of the surplus capabilities**.[38] (bold emphasis added, bold italics in BC Hydro original)

In sum, the correct step for the Commission is to use the best evidence of export prices and not dated forecasts that have not been documented or speculative hope for an emerging market, unsupported by data.

Finally, Mr. Bechard has stated that British Columbia Hydro has a large profile of U.S. transmission rights to move 2,500 megawatts of capacity from the Northwest into California.[39] This seems a bit large given the transmission constraints set out in the WECC's 2016 power supply assessment.

[38] Ibid., page 3.
[39] Technical Input Proceedings Vancouver, Volume 12, Allwest Reporting, October 14, 2017, pages 1656 through 1663, lines 22 through 25.

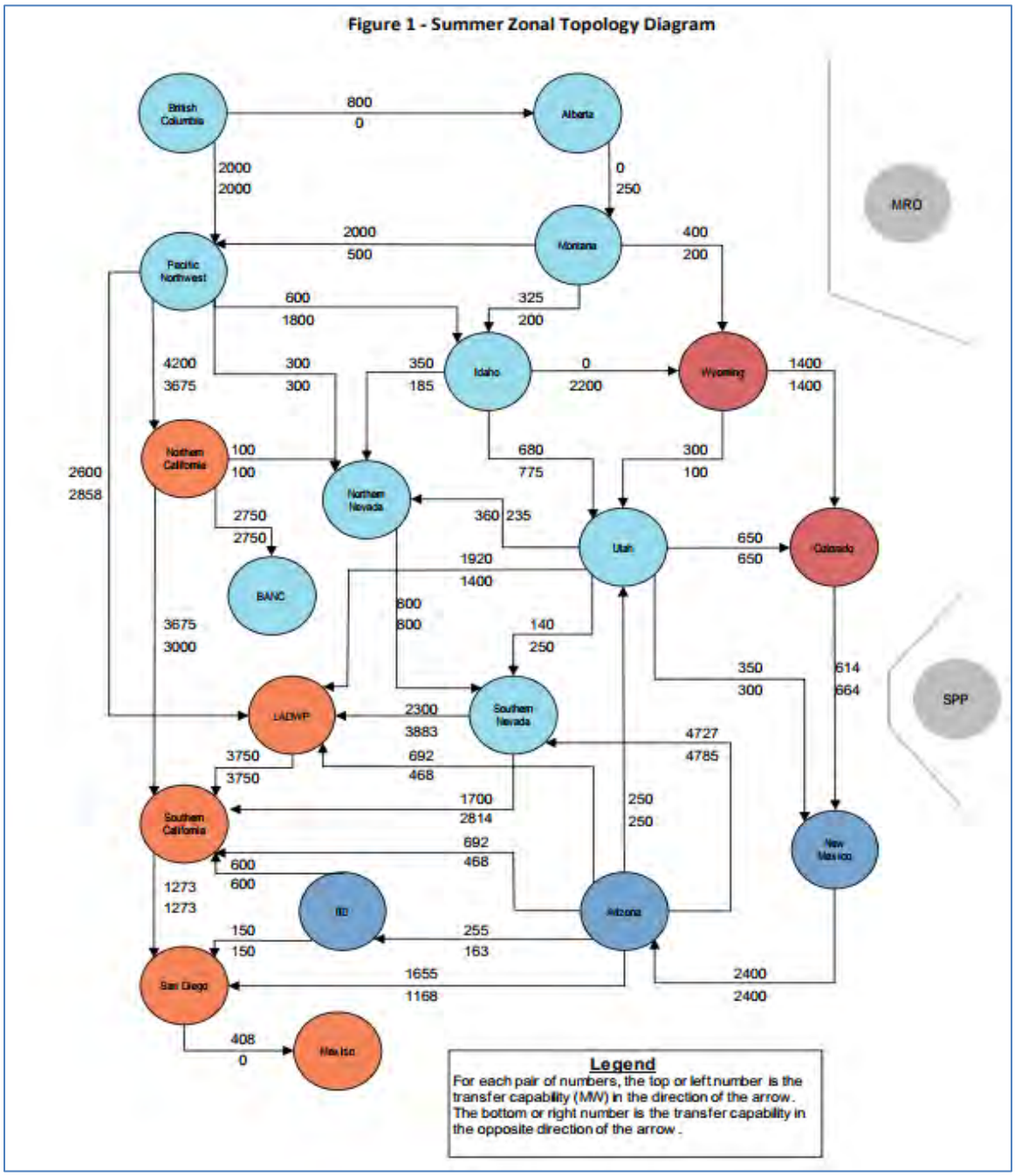

Figure 4: WECC Summer Transmission Capacity Limits[40]

[40] WECC, "2016 Power Supply Assessment," December 2016, page 19.

Addressing British Columbia Hydro's October 14, 2017 Comments

British Columbia Hydro found five implicit and explicit assumptions in the BCUC's alternative scenarios to be unrealistic.

1. **Treats DSM as an alternative when it is included in all portfolios.**

BC Hydro suggests that the BCUC has wrongly assumed in its alternative portfolio that "we cease DSM if we build Site C" (slide 27, October 14 2017). This significantly oversimplifies the issue. BC Hydro will clearly not "cease" DSM if Site C is approved. It is not permitted to do so. The question is, what can BC Hydro achieve by ***maximizing*** DSM efforts and expenditures, and is this a valid component of an alternative portfolio. In our view it is, and the Commission should retain DSM measures in its alternative portfolio. The evidence is that BC Hydro has been scaling back on DSM expenditures since 2014, driven in part by surplus capacity and revenue requirements.

British Columbia Hydro has warned the BCUC that they are "currently reviewing its DSM expenditures in light of changes to several initiatives and actual spending may vary from estimates."[41]

The BCUC clearly considers DSM a central policy choice. British Columbia Hydro admits that it's elective. We see from BC Hydro's 2016 Revenue Requirement Application, Appendix C p. 9 that BC Hydro's expenditures on DSM decline significantly between 2014 and 2016:

[41] BC Hydro. "BC Hydro Submission to the British Columbia Utilities Commission Inquiry into the Site C Clean Energy Project," August 30, 2017, page 8.

Appendix A

F2014 – F2016 DSM Expenditure Schedule

$ MILLION	F2014	F2015	F2016
Codes and Standards	2.4	4.0	4.2
Rate Structures	6.5	2.0	1.7
Programs			
Residential	30.4	17.7	18.9
Commercial	66.4	39.5	40.0
Industrial	101.9	64.3	42.9
Total Programs	198.7	121.5	101.8
Supporting Initiatives	28.7	20.6	20.3
Total Energy Efficiency Portfolio	236.3	148.0	128.0
Capacity Focused DSM	0.0	2.4	3.1
Total	236.3	150.5	131.1

Appendix B

Figure 5: 2016 RRA, Appendix C, page 9.

The evidence of the UBC Program on Water Governance filed in this proceeding F106-1 (at pp. 82-83) demonstrates credibly that this is linked to drops in BC Hydro's load forecasts and revenues. Therefore, it is a legitimate component of the Commission's alternative portfolio that BC Hydro resume enhancing DSM expenditures rather than diminishing them.

Indeed, in its initial filing, BCH used planning for DSM as evidence for the need to increase capacity, implying they see Site C as an alternative to sustained future DSM programs.[42]

2**. BC Hydro builds and finances all alternative resources**

The Commission has criticized British Columbia Hydro's decision to assume 100% debt financing for Site C, but more costly financing for other resources:

> Financing costs: The reduction of financing costs of $26/MWh, which is enabled by transferring some of the financing costs from BC Hydro ratepayers to taxpayers, does not appear to be built into the Alternative Block

[42] BC Hydro. "BC Hydro Submission to the British Columbia Utilities Commission Inquiry into the Site C Clean Energy Project," August 30, 2017, Appendix B, page 11.

> UEC. If two portfolios are being compared, it is important to ensure that the basis of comparison is the same. If the same debt financing assumption is not being applied to the Alternative Portfolio, and a full weighted-average cost of capital is assumed instead, the Panel also draws a preliminary conclusion that this reflects an implicit assumption that the Alternative Portfolio will not be constructed by BC Hydro. This results in an "apples to oranges" comparison. The Panel finds that the reduction of the UEC to account for reduced financing costs distorts the analysis of unit energy costs comparisons.[43]

The Commission did not make this assumption in their alternative portfolio analysis. It was unclear from Mr. Reimann's presentation on October 14th as to why BC Hydro pursued this point given the Commission's comments in the preliminary report. Mr. O'Riley commented:

> So I think what we're saying here is there was a suggestion in these analysis that perhaps it made sense for BC Hydro to kind of reverse the policy that had been in place for, you know, almost 30 years and go back to developing all the resources or perhaps financing all the resources, and I think what we're saying is we think that would be a mistake. <u>We think that's not our core competency and we don't think we bring expertise and we think we'd run into a lot of challenges if we were starting to develop small, lower resources around the province</u>. So that's the point we're trying to make with this.[44] (emphasis added)

Mr. O'Riiley's comments appear to be a detour around the clear statement of the problem that the Commission's plain question highlighted:

> Well, let me ask you tough question then. So there's not enough load growth to justify any more IPP contracts, but there is enough load growth to justify the construction of a large dam project? [45]

BC Hydro's response reveals the Corporation's paradigmatic resistance to fairly considering alternatives to Site C. Fortunately, neither the Commission's preliminary report, nor the Alternative Portfolio described in A-22 suffer the same flaw.

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[43] Preliminary Report to the Government of British Columbia, British Columbia Utilities Commission, September 20, 2017, page vii
[44] BCUC. "Technical Input Proceedings" October 14, 2017, page 1647
[45] Ibid., page 1646, lines 22-26.

If British Columbia Hydro actually has access to 100% debt financing, a project developer will depend on British Columbia Hydro's credit support to build their project. In this case, the windmill, geothermal, or solar project will also enjoy low cost financing.

It is a well-known principle of project financing that the credit support flows from the customer to the project. Customers with tax recourse powers enjoy a lower cost of capital than those without the ability to tax. Windmills built for public utilities with these powers enjoy lower project financing than those without since the investors know that their investments are more secure.

Ownership of the project does not, in itself, determine the cost of capital – the cost of capital is based on the guarantee of repayment.[46]

3. Battery costs are low

As I have noted above, the choice to supply firming and shaping from batteries is likely to be more costly than using the non-treaty storage at Mica. However, battery costs have been declining markedly in recent years.

Lazard has published ten summaries of the Levelized Cost of Energy for a variety of generation types. These studies are highly regarded since they do not represent advocacy. Instead, they represent a balanced attempt to document the major changes the industry has seen over the past decade.

In November 2015, Lazard commenced a new set of annual studies on storage.[47] Their unsubsidized summary indicates that storage options are about to overtake aeroderivative turbines:

[46] Wind Power: The Industry Grows Up, Rebecca Busby, page 119.
[47] Lazard's Levelized Cost of Storage Analysis — Version 1.0, November 2015.

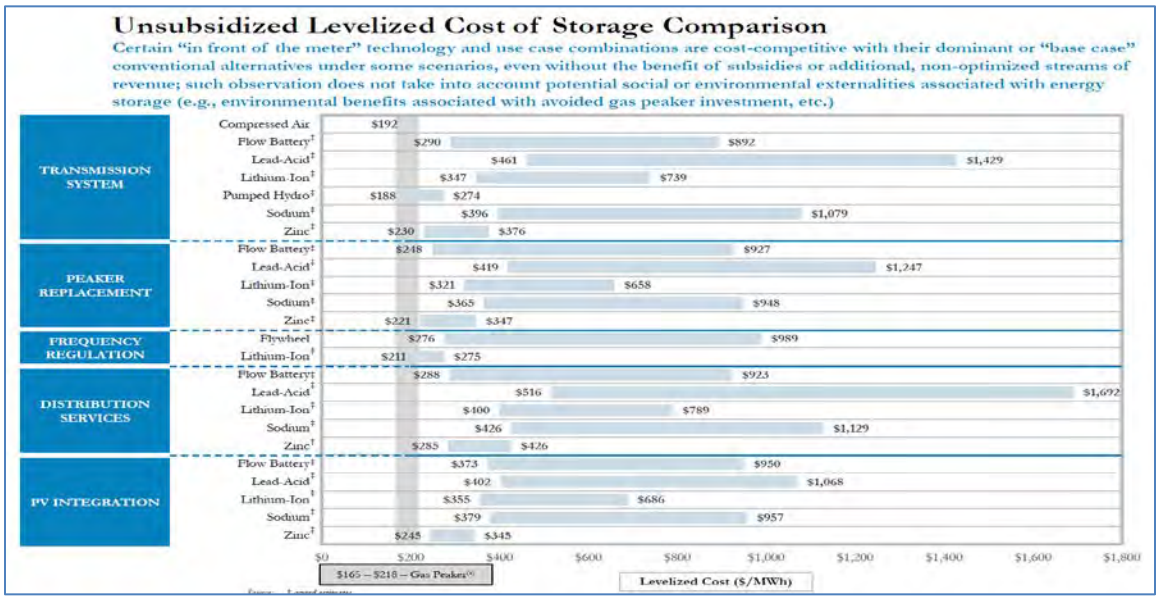

Figure 6: Lazard 1.0 Estimates of Storage Cost[48]

Last year Lazard published version two of their study:

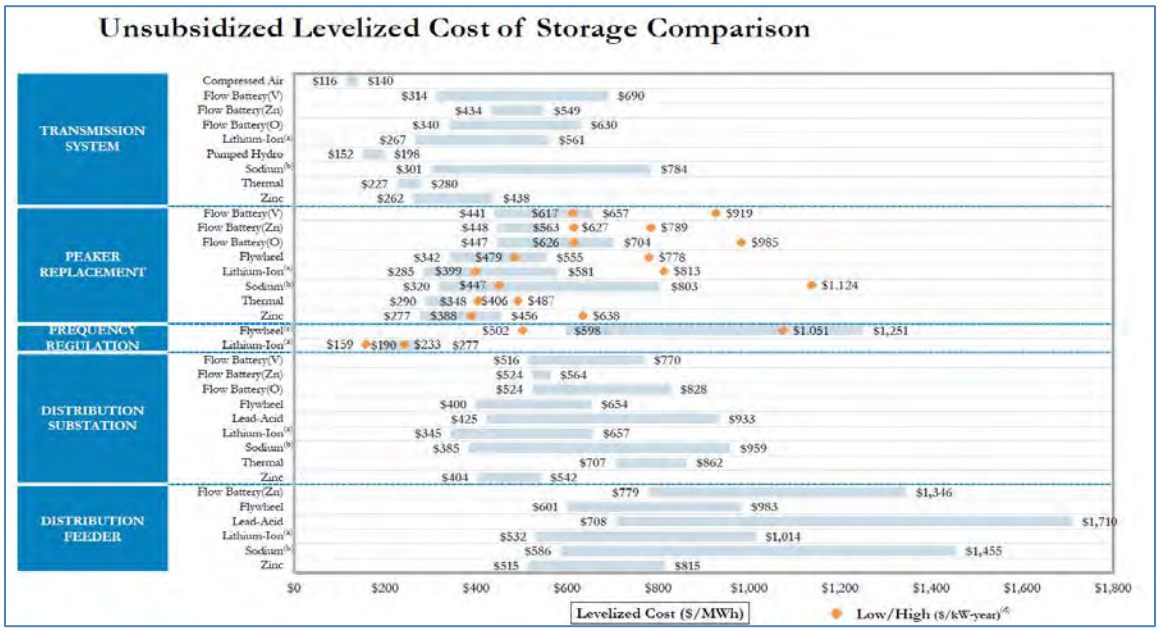

Figure: Lazard 2.0 Estimates of Storage Cost[49]

[48] Ibid., page 9.
[49] Lazard's Levelized Cost of Storage Analysis — Version 2.0, December 2016, page 11.

The highest profile turbine replacement storage option – lithium ion – has fallen from a range of US$347/kw/year to US$749/kw/year down to US$285/kw/year to US$581/kw/year.

These are dramatic decreases as I noted in a previous submission, Duke has announced a regulatory filing for a 13 MW utility scale project for approximately $200/kw/year.[50]

4. Optional time-of-use estimates are dated with significant deliverability risk

These rates would mostly apply to industrial customers and not residential ones. As we have discussed in previous submissions and as BC Hydro admitted in their technical presentation on October 14, the load required by industrial customers has declined significantly since 2008.[51,52] The only tangible way this might affect residential rate payers is if electric vehicles begin to form a significant portion of transportation infrastructure. Time-of-use payments would push electric vehicle owners to charge their cars overnight.

5. Wind cost declines are optimistic

All of these predicted cost declines are supported by precedent and authoritative sources.

A variety of industry sources provide a favorable picture of wind and solar cost declines than that assumed by British Columbia Hydro. The following two charts have been taken from the most recent Lazard study on the Levelized Cost of Energy (LCOE) generation.[53]

[50] Duke Energy. Duke Energy to invest $30M in Ashevill battery energy storage systems. September 21, 2017. page 2.
[51] BC Hydro. Site C Inquiry: Presentation to Commission Panel. October 14, 2017. Slide 14
[52] Costs of Continuing Site C and the Alternatives, Robert McCullough, August 30, 2017, pages 36-38.
[53] Lazard's Levelized Cost of Energy Analysis – Version 10.0, Lazard, December 2016, page 10.

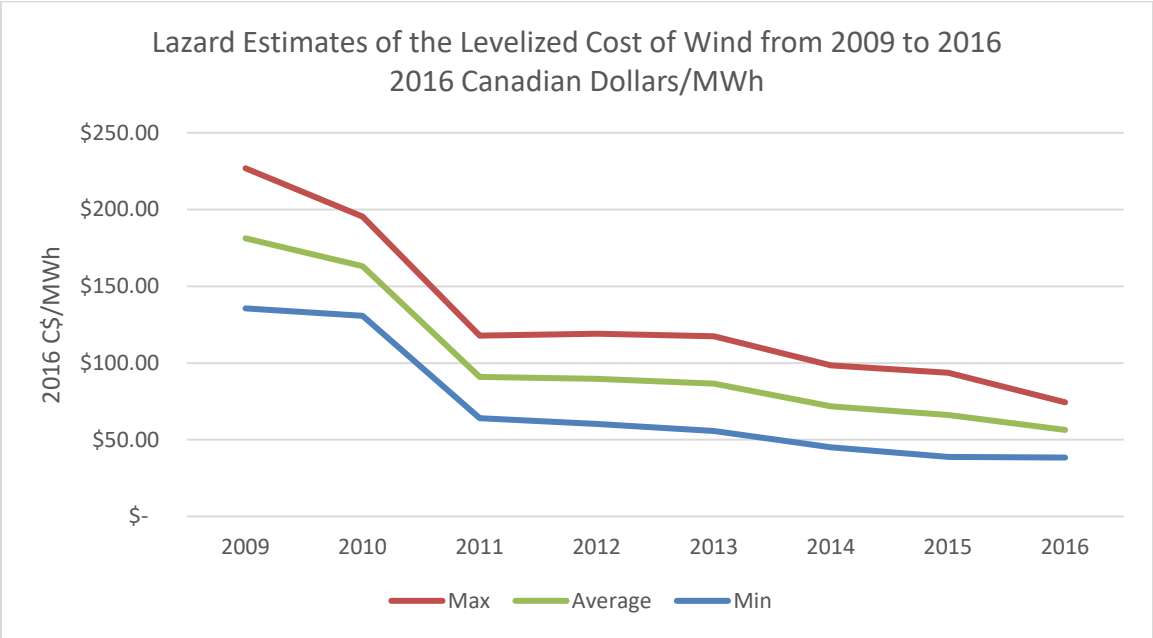

Figure 2: LCOE of wind generation from 2009-2016.

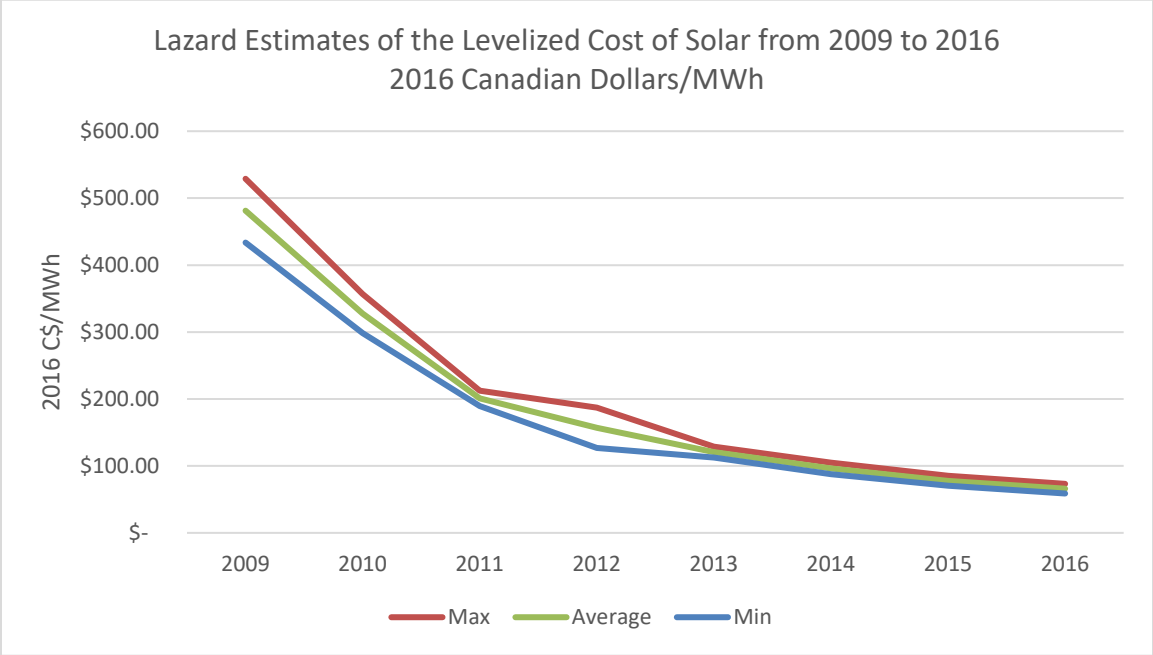

Figure 3: LCOE of solar generation from 2009-2016.

Not only are the rates of decline in cost remarkable, the absolute levels reported by Lazard are declining below traditional fossil fuel generation.

A number of studies point to additional future reductions. One very authoritative study was issued by the International Energy Agency last year.[54] The IEA bases its quantitative figures on the mean response of over one hundred industry experts, and nearly all agree that wind costs will decrease significantly over time from current levels.

According to the report, the LCOE of onshore wind energy is expected to continue falling until at least 2050. While offshore turbines will become practical sources of energy in the medium-term, onshore wind is currently competitive with all major sources of energy generation.

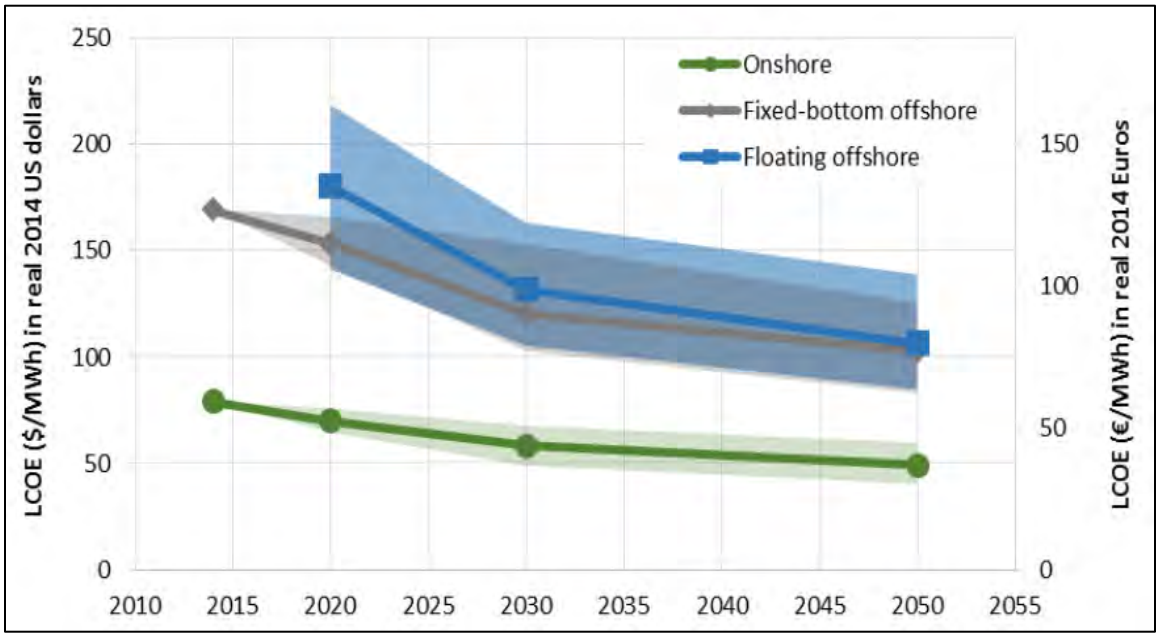

Figure 4: IEA predicted LCOE of wind turbines from 2014-2050 in 2014 US$.[55]

The IEA expects that most of these cost reductions will come about as a result of wind turbines operating for longer, being more efficient at generating power, and a lower cost of production and operation. The table below summarizes the IEA's estimate of the percent change of certain statistics of onshore wind from 2014 to 2030:

[54] Forecasting Wind Energy Costs and Cost Drivers: The Views of the World's Leading Experts, International Energy Agency, Ryan Wiser, Karen Jenni, Joachim Seel, Erin Baker, Maureen Hand, Eric Lantz, and Aaron Smith, June 2016.
[55] Ibid., page 7.

Specification	% change by 2030
Capacity Factor	+10%
Project Life	+10%
CapEx	-12%
OpEx	-9%

Table 1: IEA's predicted change in key wind project statistics/specifications.

Except in the most pessimistic scenario, this technological improvement will result in a dramatic reduction in the LCOE for producing wind power.

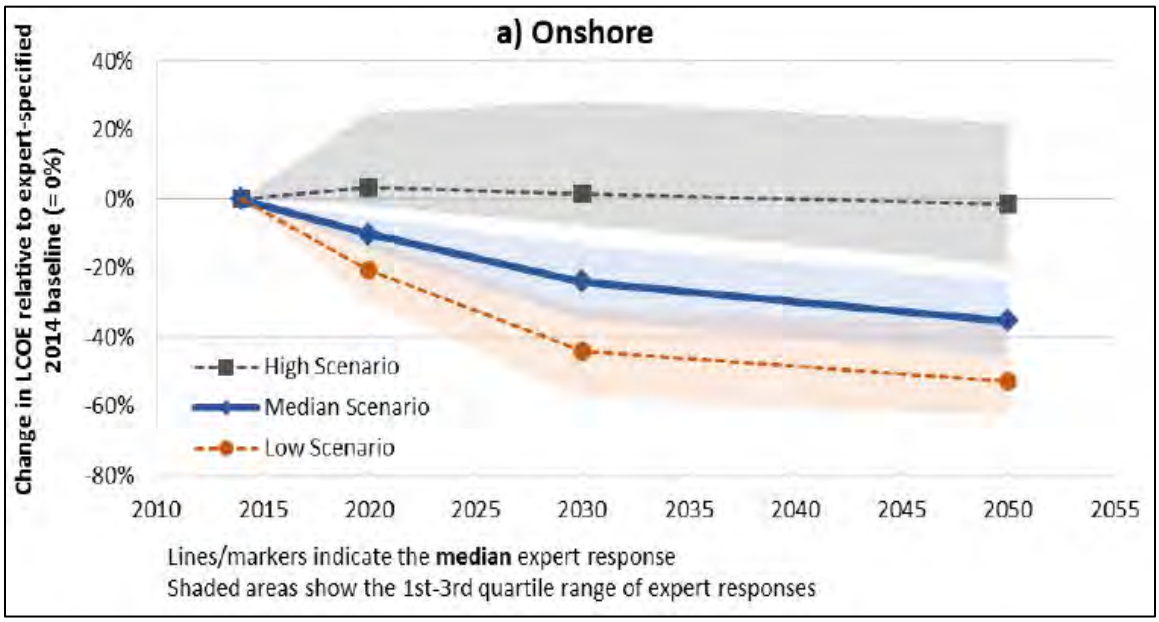

Figure 5: IEA's predicted percent change in cost of onshore wind projects 2014-2050.[56]

The LCOE of wind is already competitive with nearly all sources of convention electrical generation, and the experts that spoke with the IEA predicted that a number of innovations will gradually reduce the price of generation. Most of these innovations, summarized below, are not the fanciful dreams of science fiction writers, but easily attained with this and the next decade's technology.

[56] Ibid., page 11.

	Wind technology, market, or other change	Percentage of experts rating item "Large expected impact"	Mean Rating , Rating Distribution 3- large impact 2- median impact 1- small impact 0- no impact	
Onshore Wind	Increased rotor diameter such that specific power declines	58%	2.5	
	Rotor design advancements	45%	2.3	
	Increased tower height	33%	2.2	
	Reduced financing costs and project contingencies	32%	2.1	
	Improved component durability and reliability	31%	2.1	
	Increased energy production due to new transmission to higher wind speed sites	31%	2.0	
	Extended turbine design lifetime	29%	2.0	
	Operating efficiencies to increase plant performance	28%	2.0	
	Increased turbine capacity and rotor diameter (thereby maintaining specific power)	28%	1.9	
	Turbine and component manufacturing standardization, efficiencies, and volume	27%	2.0	
	Improved plant layout via understanding of complex flow and high-resolution micro-siting	27%	2.0	
	Integrated turbine-level system design optimization	23%	2.0	

Figure 6: Predicted cost-saving innovations in onshore wind generation.[57]

The table below summarizes the predicted change in the LCOE of wind energy according to various sources. While BC Hydro forecasts no reduction, other authoritative agencies forecast a reduction of between 10 and 17% over the planning period.

Overall, British Columbia Hydro's current estimates are high – very high – compared with industry estimates and actual wind farms operating nearby in Washington State. Industry expectations indicate a continued decline in costs – even after the rapid declines in recent years.

Source	2017 C$/MWh	2020 % change in costs	2025 % change in costs	2030 % change in costs	2035 % change in costs	2040 % change in costs
BCH [58]	C$104.77-C$315.48[59]	-	-	-	-	-
Deloitte	-	-	-10-12%[60]	-	-	-
Lazard	C$69.04[61]					
IEA	C$76.97[62]	-	-	-12%[63]	-	-
EIA	C$72.13[64]	-	-	-	-	-17%[65]

The Commission's three scenarios use wind prices that are within the Lazard range. [58]

[57] Ibid pg. 30

Initial wind builds	Name	Size	Cost
Wind - PC 18	F2039	138	$1,895
Wind - PC 48	F2040	150	$1,893
Wind - PC 20	F2041	156	$1,888

Lazard's most recent range for on-shore wind is C$1,500 to $C2,040.[59]

[59] Lazard's Levelized Cost of Energy analysis – Version 10.0, December 2016, page 19.

APPENDIX A
MR. McCULLOUGH REPLY TO BC HYDRO REGARDING FORWARD MID-C MARKETS

At several times during the Site C Inquiry, British Columbia Hydro has stated that it can sell surplus energy and capacity at the Mid-Columbia hub at prices high enough to cover Site C's costs. In BCH's August 30, 2017 Submission in this Inquiry (F1-1), they forecast that by 2024, Mid-c will likely be $45/MWh in 2017 Canadian dollars.[60]

The best evidence of the accuracy of British Columbia Hydro's price forecast are actual transactions. If the price forecast is vintage, current transactions will differ. This is the case here. The forward price of Mid-C electricity is markedly different from BCH's BCUC submission forecast. In our September 13, 2017 (F35-5) filing in this proceeding[61] as well as in our September 24, 2017 submission to the BCUC (F35-7),[62] we included the 10-year forward price of Mid-C and compared it to the forecast BC Hydro produced, implying the existence of forward markets going out 10 years.

Additionally, on October 13, 2017 I stated that "No, but we can buy the power ten years out. So, I don't have to forecast it. I can actually call up Morgan Stanley or Powerex and put it in order, and it will be delivered 10 years from now, at a set price."[63]

On October 14, 2017, Mr. Bechard stated it was untrue that you could purchase a contract with a phone call.[64] He goes on to say that his traders are in constant contact with brokers.[65]

Bechard claims for "2023, 2024, 2025, 2026, we don't see a record of that ever trading on the exchange,"[66] saying he doesn't think it is possible to do a forward curve from the forward trades.[67] Later Bechard argues that forward markets may be entirely different over six months.[68]

The statements are incorrect.

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[60] BC Hydro. BCH BCUC submission F1-1. August 30, 2017. Page 64
[61] McCullough Research Submission F35-5, September 13, 2017, pp. 27, 28 Figures 17 & 18
[62] McCullough Research Submission F35-7, September 24, 2017, p. 2 Fig 1
[63] October 13 Technical presentation transcript. Page 1232:6.
[64] October 14 Technical presentation transcript. Page 1656:17.
[65] Ibid. Page 1656:23.
[66] Ibid. 1657:11.
[67] Ibid. 1657:21.
[68] Ibid. 1658:5.

First, commodity brokers who are active at ICE and CME can indeed place orders immediately. As in any market, the current posted prices may or may not yield a transaction. However, the point is that these are real prices for a real product. This is not a forecast. This is better than a forecast. In actual trading, the posted prices are part of the forward curve computations that drive risk analysis and day end market to market calculations.

I have attached several pages from a textbook for traders showing this process.[69]

Second, it is not clear why Mr. Bechard called New York to find whether Intercontinental Exchange was relevant to the market. British Columbia Hydro specifically references ICE in some of their tariffs as well as their important OATT tariff at the U.S. Federal Energy Regulatory Commission, not to mention orders from this very commission.[70,71] Clearly, British Columbia Hydro is familiar with ICE and utilizes data from ICE.

The claim that there is no trading post 2023 is particularly puzzling. This effectively repeats the complaint in F1.12 Appendix C that natural gas has no forward trades. In my comments on that submission, I submitted the actual market report from CME to show the opposite.[72] In this case, I have reproduced the market report from Platts that shows ongoing activity through to December 2025 earlier in this submission.[73]

Regarding his point that you cannot generate a forward curve from this data, this contradicts common practice at every trading floor I have ever visited or worked with. Forward curves are updated daily in order to evaluate risk limits and mark to market gains and losses.[74] However, this is not a matter that requires debate since ICE/Platts provides this

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[69] Satyajit Das. Traders, Guns, and Money. July 17, 2017. Page 25-27

[70] BC Hydro. *BC Hydro Submission to the British Columbia Utilities Commission Inquiry into the Site C Clean Energy Project.* August 30, 2017. Appendix F Page 7.

[71] British Columbia Hydro and Power Authority ~ Amendments to the Electric Tariff and the Open Access Transmission Tariff ~ Final Order

Collection	Orders
Date	2015-03-12
Document No.	G-36-15
Order Type	G-General
Company Name	BC Hydro

[72] October 14 Technical presentation transcript. Page 1567:4.

[73] ICE MDC contract report on October 12, 2017.

74 ICE. MID-COLUMBIA DAY-AHEAD PEAK FIXED PRICE FUTURE <https://www.theice.com/products/6590351/Mid-Columbia-Day-Ahead-Peak-Fixed-Price-Future>

exact service based on forward prices to the industry.[75] I have attached the Platts methodology document to this affidavit.

In sum: British Columbia Hydro has made incorrect statements concerning my submissions in the Site C Inquiry.

Relevant Oral Testimony reproduced for convenience:

Mr. McCullough Oral Testimony Oct 13:

> "The last area where we have a comparative advantage is the Mid-Columbia. The Mid-Columbia has been around for 30 years. I helped start the Mid-Columbia market as a boy. We went to FERC, we got permission to have market pricing. That started right here in the northwest power pool. That was regarded as very adventurous in 1987. It is now the largest such market in the world, it is a completely open outcry market. Unlike some of the other markets, it is not subject to bureaucratic management. It is distinctly a laissez faire undertaking. It is so deep that it has futures and derivatives on all the major exchanges. For the next ten years I could take out my cell phone and actually buy a block of power for 2025. The price is out there. They might want more than my credit card, but the fact is we don't have to speculate on those prices." [76]
>
> "In the Northwest power pool where we live, it was so surplus on capacity for now into the foreseeable future, you can't sell capacity. I checked whether Powerex had sold any capacity on the west coast, and it was minuscule. And that's going to continue for quite a while, according to the authoritative materials from the North American Electric Reliability Council, who have the legal responsibility for maintaining that." (T p 1228 lines 15-23)
>
> …
>
> COMMISSIONER COTE: Just one question. I believe I heard you say that we are pretty good at forecasting future market prices about 10 years out. Is that true?
>
> MR. McCULLOUGH: No, but we can buy the power ten years out. So, I don't have to forecast it. I can actually call up Morgan Stanley or Powerex and put it in order, and it will be delivered 10 years from now, at a set price. And that's the right economic calculation for us, because we know that our

[75] S & P Global, Platts. *Methodology and specifications guide Platts ICE Forward Curve electricity*. February 2017.
[76] Transcript pages 122-1224, lines. 22-12.

> magic 8 ball is limited. I, by the way, keep a magic 8 ball on my desk to remind me that my forecasting is limited. But the good news about mature and deep commodity markets is I don't have to make that guess, so long as there is a deep market out there, and get a firm estimate of what those prices are all the way out.[77]

BC Hydro Mr. Bechard (October 14, 2017

> The presenter left the impression that mid-C regularly trades in the open market ten years out, and in fact I think he said you could call up on your cell phone and get a ten-year contract today.
>
> That's just simply not true. We trade mid-C power every day. We're 20 to 25 percent of the spot trades that occur at mid-C every day. So, we watch that market very, very carefully. We have term traders that are constantly looking at those markets.
> ...
> What really is the case for mid-C power, the front three years trade on a fairly regular basis.
> And I'd say they're fairly liquid. The fourth and fifth year trade sporadically. 2022 -- our records show 2022 last traded in August. So, you'd get a feel for how often that trades.
>
> 2023, 2024, 2025, 2026, we don't see a record of that ever trading on the exchange. I asked
> our term trader yesterday, he sits right next to me, to shout over to the broker in New York to see if he sees any trades on -- in history, for 2023, 2024, 2025, and '26. His answer was, you know, a flat no. They've never seen that either.[78]

[77] Transcript page 1232 lines 3-18
[78] Transcript page 1656 l. 12-23 & 1657 l.5-17

List of attachments:

1) Traders, Guns and Money (pages 4-6)

2) U.S. benefits from Columbia River Treaty

3) Non-treaty storage agreement

4) Platts methodology document

5) Columbia River Treaty Factsheet

6) Administrators decision record

prices may rise and would like to hedge his risk to wheat prices increasing.' This would lead to admiring looks from the Chinese delegation.

My description of options was similar. 'What is the problem with selling forward?' I would ask. 'The farmer is protected from losses. But he gives up the opportunity to benefit from higher wheat prices. This is where options come in. What the farmer in effect needs is *insurance* against wheat prices falling. He could buy a put option. If prices fall below an agreed level (known as the strike price) then the seller of the option pays the farmer the difference between the low actual market price and the agreed higher strike price. The farmer gets the best of both possible worlds. If prices fall then the farmer is protected. If prices rise then the farmer benefits from the higher price. It is price insurance. The farmer pays a fee (known as the option premium) for this insurance.' Most corporate treasurers and fund managers would be frowning about the cost of this insurance at this point. The Chinese delegation's joy would know no bounds. This was simply amazing!

'The baker is concerned mainly about price rises. If prices fall then he can buy his wheat more cheaply. If he wants protection only against higher prices, then he buys a *call* option. If prices go down then he is free to buy wheat at cheaper prices. In return for getting insurance against higher prices, the baker pays a premium to the seller.

And the seller of the option – known as the option writer? Well, he took on the risk of a price change because he is paid a fee to assume the risk. He acts as an insurer. The seller may also have an underlying position that offsets the risk on the option. Traders generally just match buyers and sellers. Also, there are ways of hedging the risk of options.'

Yes, that was all there was to derivatives. 'Derivatives' was the generic term for forward and option contracts. They were really quite simple.

Betting shops

Derivatives, at least in the form of forwards and options, have existed for a long time. The Chicago Board of Trade (CBOT) has traded futures (basically a forward contract) on many agricultural commodities since the nineteenth century. The major users were really farmers, buyers of commodities and grain traders.

For a hundred or so years, derivatives meant forwards/futures and option contracts traded on exchanges such as the CBOT and its arch-rival

the Chicago Mercantile Exchange (CME). A futures and option exchange is like a stock exchange. The brokers own the exchanges, customers pay a commission to trade on the exchange, and the exchange also clears trades and acts as a guarantor of the risk of the traders using a system of security deposits (known as initial and variation margining).

The first changes came about in the 1970s when futures on financial commodities (such as currencies and interest rates) were introduced. Stock options were listed and traded, but the markets remained small and illiquid. They were the arcane preserve of a small group of specialists. The major breakthrough occurred in the late 1970s – the swap market started. It ushered in the over-the-counter (OTC) market. It was the start of the golden age of derivatives.

Swaps are basically forwards. Swaps enable you to exchange one series of future cash flows for a different series of cash flows. For example, you could exchange a series of cash flows that were at a fixed rate for another where the rates were reset periodically (floating rates). This is an interest rate swap. You could exchange a series of cash flows that were in dollars for another series of cash flows in yen (a currency swap). You could even exchange a series of cash flows based on interest rates for a series of cash flows based on equity price changes (an equity swap). The Indonesians had used a version of this simple arrangement.

The emergence of swaps was important. Major banks and securities dealers went from being minor players to centre stage. Once they worked out the large sums of money to be made, they became fervent advocates of the OTC derivatives markets.

The OTC format allowed a great deal of customization of structures. To this day this remains a key benefit of the OTC market that fans cite unceasingly. There was also the small issue of transparency, mainly its absence in OTC markets. If you traded on exchanges, you were bound by the rules of the exchange. Everybody saw what you were doing. The OTC market was a gray world where dealers dealt with each other or with clients. Information about trades and prices were less easy to come by, which suited the dealers just fine. It allowed them to use the lack of transparency to make money from their clients and each other.

The emergence of swaps and the OTC markets changed the dynamics of derivatives forever. The exchanges didn't know it then. Their cozy

clubs were about to be relegated to a distant second place in the most profitable business emerging in finance. A gigantic system of betting on changes in prices was just beginning – it was called *financial derivatives.*

A gigantic system of betting on changes in prices was just beginning – it was called *financial derivatives.*

Secret subtexts

The known known of derivatives was straightforward. We proselytized with evangelical fervour on the benefits of derivatives for hedging. The poor farmer and the unfortunate multinational mining company subject to wicked and uncontrollable market forces figured prominently in our pitches. Our audiences listened to how derivatives would save them from an awful fate.

And the risk of derivatives themselves – the known unknowns, unknown knowns, unknown unknowns? Well, they were generally left for the clients to discover for themselves. The rule was *caveat emptor* – buyer beware. So, what was the great secret? There were a few.

Derivatives are typically cash settled. This means that the farmer does not need to deliver the wheat. Instead, at the agreed delivery date a calculation is done. The actual market price of the wheat on that day is compared to the price agreed under the forward contract. If the market price is lower than the agreed forward price then the farmer gets the difference. When the farmer actually sells the wheat he gets a lower price. But the payment under the forward contract (the gain) boosts the farmer's receipts to the locked-in agreed price. If the market price is higher than the agreed forward price then the farmer pays the difference. He makes a loss. The farmer's loss is offset by the gain he makes when selling the wheat normally because the market price has gone up. Either way he ends up getting the agreed price, right?

The idea is simple. I generally emphasized the flexibility of cash settlement. The farmer continues to deal with whoever he normally sells grain to. The farmer hedges separately with a third party – us – without disrupting his normal trading relationships. This gives the farmer flexibility in timing when he hedges. It lets him get the best price. It was hero of the socialist revolution stuff. But there was a subtext.

U.S. Benefits from the Columbia River Treaty – Past, Present and Future: A Province of British Columbia Perspective

BC Ministry of Energy and Mines

June 25, 2013

TABLE OF CONTENTS

EXECUTIVE SUMMARY

In 1964, Canada and the Unites States (U.S.) ratified the Columbia River Treaty (Treaty). The impetus for the Treaty was the disastrous flood of 1948 which devastated the City of Vanport and cost many lives, along with growing power demand in the Pacific Northwest. In exchange for an equal share of the U.S. downstream power and flood control benefits, Canada agreed to build three dams in British Columbia and allowed one U.S. dam to flood into Canada. The Canadian facilities vastly reduced flood risk in the U.S. while enabling the production of significantly more electricity at U.S. hydropower facilities.

The U.S. prepaid Canada $64 million to rent 8.45 million acre feet of storage space in the new Canadian reservoirs for 60 years to support assured flood control which resulted in reduced flood damage and increased safety for U.S. citizens. At the same time 110,000 hectares (270,000 acres) of Canadian ecosystems were inundated; residents, First Nations, communities and infrastructure were displaced; farms and forestry activities were impacted. The U.S. also committed in the Treaty to paying Canada half of the incremental power potential that could be produced because of the new flow regimes that the Treaty dams made possible. The Treaty has no end date but either country can unilaterally terminate the Treaty from September 2024 onwards provided that at least 10 years notice is given. This ability to terminate the Treaty, and changing flood control provisions whether the Treaty is terminated or not, have prompted both countries to undertake a review of the Treaty to determine its future.

The Treaty has worked well in optimizing flood control and power objectives. However, as society's values change, so have the benefits of the Treaty. The coordinated management of river flows and storage reservoirs has since produced a wide range of additional benefits to interests such as ecosystems, navigation, water supply and recreation. Yet, the existing and future benefits under the Treaty, and the risks and losses that could occur if the Treaty is terminated are not well understood.

Treaty Benefits in the U.S.

Flood Control: Half of the available flood storage in the Columbia basin is located in British Columbia. Since the Treaty storage became operational, there has never been a flood causing major damage along the Columbia River, avoiding $2 billion in potential damage in one year alone.[1] In 2024, regardless of whether the Treaty continues or is terminated, planned assured flood control operations change to a more ad hoc "called upon" flood control. This means that all U.S. reservoirs that are able to reduce damaging flood flows at The Dalles will need to be drafted deeper than is current practice before Canada can be "called upon" to provide additional assistance. At this time, the Canadian and U.S. Entities disagree on how called upon flood control would be implemented. Regardless of this disagreement, modelling has shown that this will increase the flood risk on the system while altering current reservoir operations and increase the risk of reservoirs not being able to refill, with likely negative consequences for a number of interests, such as fisheries, ecosystems, power production and water supply. British Columbia is open to discussing alternative flood risk management arrangements that would make better use of existing facilities, increasing certainty of operations and avoiding negative impacts to U.S. interests.

[1] February 2013. Permanent Engineering Board Meeting.

Hydro power: The Treaty has significantly enhanced hydropower production in the U.S. and continues to provide predictable and reliable flows that translate into firm energy so that utilities can meet their customer load. During the Treaty review, Bonneville Power Administration's analyses have focused on average energy benefits based on assumed Canadian operations, and presented the information in a way that could lead people to believe that the power benefit of continuing the Treaty is only 10% of the Canadian Entitlement. British Columbia believes that the value is much higher than the current return of the Canadian Entitlement when power benefits along with other values and interests that benefit from coordinated operations are factored in.

Coordination under the Treaty allows the hydro system to respond to seasonal challenges during cold winter conditions when inflows are reduced, as well as dry hot summers when irrigation, fisheries and recreation are competing for the same low flows. In both instances, Canada releases flows first to maximize U.S. power production. Without the Treaty, BC Hydro would operate solely for British Columbia domestic energy and other needs in a manner quite different than today, with system coordination greatly diminished. This would create significant uncertainty for the U.S. that would affect system planning and reliability across the U.S. portion of the Columbia River Basin.

Ecosystems: Flexibility within the Treaty has allowed changes in coordinated operations to benefit ecosystem values. Supplementary agreements have contributed to enhancing ecosystem values, particularly U.S. salmon recovery, by augmenting flows in the spring to better imitate the natural hydrograph, and augmenting flows during late summer and during dry years which are particularly critical to fish survival. As climate change predictions foresee hotter and drier conditions for the lower Columbia Basin, this coordination will become only more valuable. Without the Treaty, these beneficial ecosystem operations would cease to exist and water in the Canadian portion of the basin would be managed solely for Canadian environmental and other interests. Past and ongoing litigation has prompted U.S. agencies, Tribes and other stakeholders to invest to heavily in ecosystem recovery over the last decades. Decisions on the future of the Treaty should ensure that these investments are not lost.

Water supply: Additional Canadian flows for power production and ecosystems during low water conditions also benefit to some degree consumptive use as U.S. water managers re-regulate flows using Grand Coulee Dam for a host of interests competing for a limited resource. The changing flood control regime in 2024, requires greater emptying of U.S. reservoirs and risks upsetting the sensitive water allocation balance that is becoming increasingly strained. Climate change predictions will likely exacerbate the current tension between water users.

Navigation: Commercial navigation on the Columbia River is a key contributor to the economic sustainability of the U.S. Pacific Northwest. Changes to Treaty flood control provisions will likely result in more frequent higher flows that could worsen navigation conditions by increasing shipping times and affecting docking operations. High flows may also increase sedimentation thereby reducing channel depth and increasing dredging costs. During low flow conditions and without Treaty flow augmentation from Canada, navigation interests will also likely be impacted by reduced channel draft, disrupting navigation and raising the risk of grounding.

Treaty Benefits in Canada

The only benefit to Canada from the Treaty is the sharing of downstream benefits from additional power production potential made possible by the coordination of flows. Half of the potential additional power that could be realised due only to Treaty operations, which is called the Canadian Entitlement, is returned to Canada in electricity at the border. The U.S. has chosen to use these Treaty power flows for other, equally important, purposes besides power production. This should not be used as a reason to reduce equitable benefits to Canada. As dictated by the Treaty, the amount of Canadian Entitlement is forecast to decrease over time while British Columbia continues to be impacted, through reservoir operations and ongoing costs to maintain the Treaty dams, and our flexibility to manage for the needs of BC basin residents is constrained in order to meet Treaty requirements for U.S. interests. This has caused some residents to question whether the fundamental Treaty principle of creating and sharing benefits equitably is still valid. Simply put, without the Canadian Entitlement, British Columbia would see no reason for the Treaty to continue.

The Future of the Treaty

The Columbia River Treaty between Canada and the United States is known throughout the world as one of the most successful examples of a transboundary water treaty. Other countries see the agreement as setting a benchmark on cooperation and benefit sharing.

The Treaty is founded on the principle, set out in the Treaty's preamble, that the greatest benefits to each country can be secured through cooperative measures. The alternatives to cooperation in each country require careful examination.

As climate change will increasingly alter the environment of the Columbia basin in the broadest sense, reservoir management and coordination are seen as important tools in adapting to climate change challenges that threaten salmon recovery, water supply and energy reliability. This would suggest a need for more collaboration, not less. As both Canada and the U.S. continue to review options regarding the future of the Treaty, it is important that citizens on both sides of the border understand how the Treaty is beneficial, who benefits, how further cooperation can enhance or create new benefits, and what is at risk of being lost if the Treaty is terminated.

DISCLAIMER: The content of this paper represents the views and perspectives of the Province of British Columbia and is not to be interpreted necessarily as the views of the Government of Canada.

1. INTRODUCTION

The Columbia River Treaty (Treaty) between Canada and the United States (U.S.) is known throughout the world as one of the most successful examples of a transboundary water treaty. Other countries see the agreement as setting a benchmark for cooperation and equitable sharing of benefits on an international river system.

The Treaty, signed in 1961 and ratified in 1964, has proven to be durable over time. The flexibility within the Treaty has allowed operations to adapt to evolving societal values. The construction and operation of Treaty dams are designed to provide flood control and hydropower benefits in both countries, and these benefits were to be shared fairly and equitably. As a result of the Treaty, development has taken place in the flood plain and costly flood damage including loss of life has been greatly reduced, while hydropower generation that has supported billions of dollars in economic development has increased.

However, demands on the Columbia River have increased significantly since the Treaty was signed. New and emerging issues, not foreseen in the 1960s, now pose significant challenges to resource managers on the Columbia River and its tributaries. Some of these challenges include: operational changes to support salmon recovery efforts and to enhance other ecosystem values; the rapid growth of renewable resources and implications for reliability of the power grid; increasing stress on water supply for urban growth, industry, irrigation and agricultural development; the continued development into the historic flood plain and implications for flood risk management; the importance of navigation and recreation in supporting the regional economy; and growing awareness and knowledge of the impacts of climate change and need for adaptation. All of these challenges have implications on current and future coordination on the Columbia River between the U.S. and Canada.

There are two important elements of the Treaty that have led both countries to launch separate reviews of the Treaty. The first is the option for either country to unilaterally terminate most provisions of the Treaty at its earliest termination date of September 16, 2024 (60 years after ratification) by giving the required minimum ten years notice. The second is the expiry of the pre-paid assured flood control operation in Canada of 8.45 million acre feet (MAF) that the U.S. purchased for sixty years in 1964 and the resulting shift to an ad hoc "Called Upon" flood control operation. Both of these changes could significantly alter the coordination benefits that have accrued to both countries through the Treaty.

There is a view in the U.S. that Canada receives a disproportionally high share of power benefits from the treaty and that those benefits should be reduced. The Province of British Columbia refutes that premise. The value of coordination to the U.S. is much broader than the value to Canada. The only benefit to Canada of continued coordination under the Treaty beyond 2024 is the return of the Canadian Entitlement, which is one half of the incremental downstream power potential resulting from Treaty operations. In order to understand the value of this coordination, U.S. stakeholders need to ask themselves: How important is knowledge of planned operations in Canada to U.S. planning for its entire coordinated system in the U.S. Pacific Northwest? How important are good communication and coordination during extreme weather events which can have significant consequences for property and safety? How important is the coordination of flows in managing and reducing ecosystem impacts and in helping U.S. salmon recovery efforts? How critical to economic

development are Canadian flow releases during summer low flow periods and droughts for water supply, recreation, navigation and fisheries? And is the value of all of these interests worth risking by terminating the Columba River Treaty? The purpose of this paper is to examine some of these questions and to provide a Province of British Columbia perspective on the U.S. benefits from continued coordination under the Treaty beyond 2024, and the risks to U.S. interests if the Treaty is terminated.

2. THE COLUMBIA RIVER TREATY TODAY

2.1 Current Operations

Hydroelectric systems in British Columbia and the U.S. Pacific Northwest are managed to both meet electricity demand and also manage the water for multiple purposes. This is a complex system, made all the more complicated by a series of dams and reservoirs where operations at one affect the others. The Treaty is implemented by the U.S. Entity, represented by the U.S. Army Corps of Engineers (USACE) and Bonneville Power Administration (BPA), and the Canadian Entity, BC Hydro. BC Hydro is a Crown Corporation owned by the Province of British Columbia (BC).[2] The Province of British Columbia is the Canadian Entity for the purpose of the disposal of the Canadian Entitlement.

Canadian Columbia River facilities

The Canadian portion of the Columbia River basin comprises only about 15% of the physical area, but contributes approximately 38% of the basin runoff on average and up to 50% of the peak flood volume at The Dalles, Oregon in high flow years. This proportion is expected to increase in the future as climate change scenarios predict the Canadian portion of the basin will get wetter and the lower U.S. portion of the basin to get dryer. The effective storage volume in Canada is 20.5 million acre-feet[3] (MAF) which is close to 50% of the active storage currently available in the entire Columbia River basin.

The Columbia River in Canada has three dams in series – Mica, Revelstoke, and Hugh Keenleyside. The upstream most project – Mica – is the largest storage on the whole Columbia system with 12 MAF of active storage. It should be noted that Revelstoke Dam is not a Treaty dam and is operated for daily/weekly shaping. Mica and Revelstoke will have a combined generating capacity of approximately 5,700 megawatts (MW) by 2024, or 50% of BC Hydro's generating capacity, and are critical in reliably meeting British Columbia domestic load. Hugh Keenleyside Dam is the third project in the series. It is a low head dam and despite being the third largest reservoir in British Columbia with 7 MAF of active storage, it has relatively little power generation. The primary purpose of this dam was to provide flood control and power benefits to the U.S. under the Treaty. In 2002, the 185 MW Arrow Lakes Generating Station was installed adjacent to the dam.

Duncan Dam (1.4 MAF) on the Kootenay River is the third Canadian Treaty dam and does not currently have any power generating capability.

[2] All proprietary rights, title, interests and obligations under the Treaty, including the Canadian Entitlement, were transferred to British Columbia under the 1963 Canada – British Columbia Agreement.

[3] Although the Columbia River Treaty called for 15.5 MAF of storage to be built at Mica, Arrow and Duncan, Mica was built with an additional 5.0 MAF of storage (referred to as Non-Treaty Storage), which is managed under the Non-Treaty Storage Agreement. The Treaty provides the foundation for the Non-Treaty Storage Agreement, without a Treaty this Agreement would not exist.

U.S. Columbia River facilities

The U.S. portion of the Columbia Basin represents approximately 85% of the physical area and contributes approximately 62% of basin runoff on average. There are eleven hydroelectric facilities on the U.S. Columbia River main stem with a combined generation capacity of 20,347 MW. Six of these projects are owned by the U.S. Federal government (U.S. Bureau of Reclamation/USACE) and five of these projects are owned by Public Utility Districts (Mid-Columbia PUDs).

Operations of these and other non-mainstem U.S facilities are coordinated by the Pacific Northwest Coordination Agreement[4] which coordinates power production while taking into account non-power uses for water resources. This agreement enables the region's major generating utilities to gain many of the coordination benefits they would realize if the system were a single utility managed by a single owner.

The largest generating facility in the Columbia River system is the Grand Coulee Dam. It is the largest hydropower facility in the United States with a total generating capacity of 6,809 MW. The reservoir has approximately 5 MAF of active storage and plays a key role as part of the Columbia Basin Project, irrigating more than 600,000 acres of farm land that produces almost $630 million per year in irrigated crops. Grand Coulee is deemed to be the cornerstone for water control on the Columbia River in the U.S.[5].

BPA describes how some aspects of the interconnected multi-use system[6] are managed in the U.S. as paraphrased below:

> The Federal Columbia River Power System is a complex system of 31 interconnected dams on the Columbia, Snake, and Willamette rivers. The dams are authorized for many purposes including navigation, fish mitigation, irrigation, and flood control. The multi purposes of the dams mean that Bonneville cannot simply produce power whenever needed. Water released at one dam for power or other purposes will affect the water and power production at all the downstream dams. *This is why international cooperation is essential* [*B.C. emphasis*]. Grand Coulee is the only significant storage dam in the U.S. on the mainstream of the Columbia River. All of the downstream dams are essentially managed as run-of-river. Bonneville has very limited control over when power is produced. Nevertheless, Bonneville must produce power to meet its load obligations and adjust generation for energy imbalance to maintain the stability of the electrical grid. The federal agencies cannot choreograph this complex operation unless they plan operations months in advance. Bonneville creates the operating plan of how water will be deployed for power and all the other system purposes 18 months in advance. This plan is then constantly adjusted for changing water

[4] PNCA is an Agreement for Coordination of Operations among U.S Power Systems of the Pacific Northwest signed on September 15, 1964 by the USACE, BPA, the Bureau of Reclamation, and the major generating utilities in the Pacific Northwest. The Agreement stipulates that the parties agree to coordinate the operation of their respective systems to provide optimum Firm Load Carrying Capability and useable secondary energy for the Coordinated Systems. It also outlines water storage and power transfer rights and obligations to all the participants to the Agreement. The current PNCA terminates on September 15, 2024, one day before the earliest termination date of the Columbia River Treaty.

[5] Information from Bureau of Reclamation's website http://www.usbr.gov/pn/grandcoulee/

[6] United States Department of Energy – Bonneville Power Administration. Docket No. NJ12-7-000, Request for Leave to Answer and Answer to Protests and Comments. Section IIB(2i) page 13-18.

conditions and plans are updated for the next day, the next week, the next month, and outward for the 18 month period. Only if the system is carefully planned can Bonneville ensure that the system will be managed to satisfy all federal obligations (which include flood control, power, ecosystems, recreation and navigation among others).

Other Agreements Stemming from the Treaty

The Treaty permits the Entities to develop agreements that allow for mutually beneficial changes to baseline Treaty operations to adjust for changing values and needs, including fisheries interests. This has led the development of a number of related agreements over the years, including the Non-Treaty Storage Agreement, Supplemental Operating Agreements, and the Libby Coordination Agreement.

When Mica Dam was constructed, it was built with an additional 5 MAF (6.2 km^3) of live storage capacity beyond what was required under the terms of the Treaty. So long as the Treaty continues, Canada cannot fully utilize this additional reservoir storage without agreement from the U.S. Entity as doing so could conflict with reservoir discharge requirements under the Treaty. As a result, this additional storage is coordinated under a commercial agreement between BC Hydro and BPA called the Non-Treaty Storage Agreement (NTSA). The NTSA provides both fisheries and power benefits as described in later sections.

2.2 A Coordinated System

2.2.1 Flood Control

Currently, Canadian Treaty dams are drawn down (or drafted) to, or below their prescribed flood control rule curves, also called storage reservation diagrams. These are derived from provisions within the Treaty and the USACE Flood Control Operating Plan. These storage reservation diagrams dictate the minimum amount of vacated space required for a given April to August inflow forecast volume so that in larger snow-pack years the reservoirs can store flood flows and reduce major downstream flood damage and risk to the public. The power draft of up to 15.5 MAF required under the Treaty operations usually causes the reservoirs to be operated lower than the flood control storage reservation diagrams, and this additional draft provides space for additional flood peak reductions. Reservoir levels can be below, but cannot be above the flood control rule curve. In other words, flood control operation for the protection of life and property has priority over operations for power or other uses.

Treaty operations have significantly reduced flood damage on the Columbia River system. Since the Treaty dams were constructed, there has never been a peak flow over 600,000 cubic feet per second (cfs) at The Dalles, Oregon, the flow considered to be the beginning of major flood damage in the lower Columbia River. Historically, prior to the Treaty, one-third of the years had peak flows over 600,000 cfs. There are four years of record where the peak unregulated Columbia River stream flows at The Dalles did or would have exceeded 1,000,000 cfs without Treaty storage: 1894, 1948, 1972, and 1974. The first two of these pre-Treaty floods caused catastrophic damage and loss of life. Moreover, the continued provision of assured flood control has enabled further development of the lower Columbia flood plain and port facilities. The USACE has estimated damages prevented by Columbia storage regulation during 1972, 1974, 1996 and 1997 at about $260, $306,

$227 and $379 million, respectively.[7] In 2012 alone, USACE estimates of flood damage prevented (by Treaty and non-Treaty facilities) was approximately $2 billion.[8] These values are not overstated as they are not inflated to today's dollars, and are based on outdated estimates of development in the flood plain. More recent estimates by USACE estimate that, on average, annual flood damages avoided on the U.S. Columbia system are approximately $100-200 million. Given that Canadian storage accounts for approximately 50% of total active storage on the system it can be estimated that the operation of Treaty projects provides approximately $75 million per year in avoided flood damages. Cumulative flood damages prevented by projects (Treaty and non-Treaty) in the Pacific Northwest have totalled almost $32 billion.[9]

The assured annual flood control operation that was purchased by the U.S. for 60 years for $64.4 million expires on September 16, 2024, regardless of whether the Treaty continues or is terminated. Thereafter, flood control will switch to an ad hoc "Called Upon" operation, described later in this paper.

2.2.2 Power Production

The coordinated power operations under the Treaty are specified in Assured Operating Plans (AOPs) and Detailed Operating Plans (DOPs) which provide assured operation of Canadian storage and more certainty with respect to the monthly volume of flows that will be crossing the border. The AOPs, prepared five years in advance under procedures set out in the Treaty, are designed to achieve a joint optimum power operation in Canada and the U.S. by regulating the flows on the Columbia River. The AOP is used to determine the downstream power benefits, which are the increased generation capability at downstream U.S. projects based on the coordinated Canadian Treaty storage operation to improve and optimize generation at downstream U.S. projects. These downstream benefits are shared between the U.S. and Canada and the resulting Canadian share is called the Canadian Entitlement.

Prior to the commencement of each August to July operating year, the Entities prepare the DOP, which allows changes in operations where the Entities agree there are mutual benefits. The changes in recent years have been primarily to address ecosystem values in Canada and the U.S. The changes included in the DOP do not affect the determination of downstream power benefits.

Within each year the Treaty Storage Regulation (TSR) studies and the weekly (or when required daily) coordination phone calls provide the U.S. Entity certainty of flows on any given day/week. Other agreements provide the ability to modify flows due to water conditions or other unusual conditions when possible for mutual benefit. The operating restriction that the AOPs, DOPs, and TSRs place on Canadian storage do not apply to or constrain management of U.S. storage. This allows the U.S. to use the improved stream flows that Canada provides in any manner that it sees fit to meet its domestic needs and allows the U.S. to manage its own system to meet multiple objectives.

The Treaty enabled additional hydropower related benefits such as installation of additional generators at downstream dams, the electrical intertie between the Pacific Northwest and California, the Pacific Northwest Coordination Agreement[4], and regional preference legislation in the U.S. for federal hydropower.

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[7] U.S. Army Corps of Engineers. *Effect of Reservoir Regulation on Flood Peaks and Damages: Columbia River Basin*. http://www.nwd-wc.usace.army.mil/crwmg/reports/

[8] February 2013. Permanent Engineering Board Meeting.

[9] http://www.nwd-wc.usace.army.mil/PB/MRC/pdf/WMBRIEF_MRC_Physical.pdf

Coordinated operation of the U.S. power system in the Pacific Northwest with the Canadian Storage under the Columbia River Treaty has provided a reliable system to serve customers electric load. Implications for reliability post-2024 are discussed in section 3.3.

One of the purposes of the Treaty is to optimize the power production of the entire coordinated system across the Basin. In low water years, or when seasonal flows are less than expected, the whole system, including the Canadian dams, enters into "proportional draft" operations. Proportional draft means that Canada provides extra water in dry years, an assured winter flow, and summer draft in long dry summers. The low generation value dams like Hugh Keenleyside are drafted before the high generation value dams like Grand Coulee. Essentially, proportional drafting means Canadian reservoirs have to release more water than inflow in dry conditions to benefit the U.S.

For example, while Arrow Lakes and Grand Coulee reservoirs have similar amounts of active storage (approximately 7 MAF and 5 MAF respectively), Arrow Lakes Reservoir has a low head dam with only 185 MW of generating capacity, while Grand Coulee is a higher head dam with 6,809 MW of generating capacity. Under the terms of the Treaty, the reservoirs are drafted in order of priority to maximize power production. What this means is that Arrow Lakes is drafted before Grand Coulee, and the very head-sensitive Grand Coulee project is able to stay at a higher elevation in order to maximize power production. This operation also provides additional benefits to recreation, navigation and other interests in the U.S. while potentially impacting similar interests in Canada.

Another example of how the Treaty helps maintain reliability is how reservoir operations respond to energy needs during the winter. In the Pacific Northwest cold arctic outbreaks typically occur once or twice a winter for periods as long as a few weeks. Cold arctic outbreaks:

- significantly increase the regional electrical load, as more heating equipment is in service more frequently and for longer cycles;
- significantly reduce inflows available for hydro-electric generation as the runoff freezes into ice and snow and melting of snow and ice is reduced; and
- virtually eliminate wind generation within the region due to the large stable air mass associated with arctic outbreaks.

In these instances, Canadian reservoirs are operated to respond to the increased power needs during low flows in the U.S. by providing assured winter flows through proportional drafting.

2.2.3 Ecosystem

Since the Treaty was ratified, society's values have changed, and environmental interests have become increasingly important in both countries. More specifically in the U.S., operations for salmon recovery have been designed so that they partially restore spring freshet flows which are needed to move migrating salmon smolts past the dams and downstream to the ocean as rapidly as practical. The Biological Opinion by National Oceanic and Atmospheric Administration (NOAA) sets passage objectives and spill (water overflow) targets for all of the Federal Columbia River Power System Dams. Recent Biological Opinions for Columbia salmon require holding as much water as possible in U.S. reservoirs through the early spring by maintaining the

reservoir levels near their flood control elevations. This provides the maximum amount of water available for discharges in late spring and summer to help fish travel downstream more rapidly. Surety of flows from Canada enables fisheries managers in the United States to better plan these operations. The Technical Management Team (TMT), comprised of federal agencies, tribes, and states, makes recommendations on U.S. dam and reservoir operations for fisheries based on the forecast runoff and the knowledge of assured Canadian operations.

Flexibility under the Treaty has resulted in operational changes (via Supplemental Operating Agreements, NTSA, and the Libby Coordination Agreement) that benefit U.S. and Canadian fish including:

- Vernita Bar protection flows for salmon;
- Draft of projects during the summer to help meet fish flow objectives at the McNary Dam;
- Chum salmon operation in fall and winter below Bonneville Dam;
- White fish and trout spawning flows below Arrow; and
- Libby white sturgeon and bull trout releases.

The Supplemental Operating Agreements, developed by the Canadian and U.S. Entities for within-year operations, generally provide for 1 MAF of flow augmentation that the U.S. can release in June/July. There have been numerous such agreements entered into over the years, beginning in the 1990s.

Treaty power and flood control operations provide ancillary benefits to ecosystems. Proportional drafting for power generation during the dry season or low flow years also enhance fisheries flows. In addition, NTSA provides additional benefits for U.S. fish interests by allowing for the use of an additional 5 MAF of Canadian storage that is not coordinated under the Treaty. The dry year release provision that is available in the NTSA is particularly valuable for U.S. fisheries interests because it guarantees the U.S. a 0.5 MAF unilateral release right for use in May/June to support salmon migration in the lower Columbia River during the driest 20% of runoff years. If the Treaty is terminated, it is unlikely that the Canadian Entity would continue to pursue these and other mutually beneficial agreements for fisheries because there would be no baseline from which to negotiate changes. The Canadian Entity would already have the flexibility to balance the interests in Canada.

3 THE COLUMBIA RIVER TREATY POST-2024

The previous chapter described how coordination under the Treaty has been successful in meeting its primary objectives while shifting operations to address values, such as fisheries, that were not contemplated in the original agreement. The following section looks forward to 2024 and beyond, and describes what will and may change, depending on the choices of both countries regarding the future of the Treaty. The first section outlines how climate change is predicted to affect the hydrology of the Columbia Basin. Climate change was not a factor when the Treaty was developed fifty years ago. However, the outlook on climate change provides the necessary context within which to examine the implications on U.S. interests into the future.

3.1 Climate Change

Climate change in the Columbia Basin continues to be researched on both sides of the border.[10] Data indicates that over the past century the U.S. Pacific Northwest and British Columbia have been getting warmer. The general trend in projected climate change scenarios is for more precipitation in winter, spring and fall, and less precipitation in summer. The snowmelt will start earlier, and spring and early-summer flows will peak earlier and be substantially higher. As well, late-summer and early-fall flows will be substantially lower and the low flows will last longer. However, because of BC's colder, higher elevation topography, snowpack in this region will be less impacted than U.S. areas further to the south.

The late summer low flows will also be exacerbated by a reduction in glacier melt as the glaciers continue to retreat. Although the impact of glacier melt on annual flow volumes is relatively minor, even glacier cover of 5%, such as in the Mica basin can contribute significant flow in the late summer. During the warm and dry summer of 1998, for example, glacier melt contributed 35% to the Mica basin's September stream flow. The impact of receding glaciers should be included in any climate change studies because of glaciers' significant effect during late summer, low flow periods.

In Canada, the Columbia and Kootenay watersheds are projected to see an overall annual increase in water supply and are expected to remain snowmelt dominated. The hydrology in these northern sub-basins will not be impacted to the same degree by climatic changes as will the lower U.S. sub-basins.

In the U.S., a number of studies indicate the changes to the annual runoff can be expected to be more significant. Many of the U.S. sub-basins will transition from snowmelt dominated to hybrid rainfall-snowmelt watersheds, and the current hybrid sub-basins will turn into rainfall-dominated watersheds. Some studies suggest that certain sub-basins could also potentially be drier with a corresponding decrease in water supply.

In general, the longer periods of low flows will coincide with periods when out-of-stream demands, such as for domestic water supply and irrigation are highest and in-stream demands, such as for hydroelectricity generation, fish habitat and recreation are critical. Higher temperatures and longer low flow periods could also pose a risk to fish stocks that are already under stress, potentially causing higher mortality rates during that period. The seasonal shift in flows throughout the entire Columbia system, and the shift from snowmelt dominated to a mixed snowmelt/ rainfall or rainfall dominated system for some of the southern sub-basins, could have other implications for U.S. flood risk management and ecosystem function on the river.

Climate change in general could result in a need to prepare for increased frequency and unpredictability of extremes in weather at both ends of the spectrum for flooding and drought. Reservoirs provide a mechanism that can assist in adapting to climate change challenges by increasing storage during times of relative water abundance and releasing stored water during times of relative water scarcity. The coordination and flexibility contained within the Treaty provide important mechanisms to help address some of the challenges climate change will bring.

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[10] BC Hydro, *Potential Impacts of Climate Change on BC Hydro's Water Resources*, 2012
River Management Joint Operating Committee (Bonneville Power Administration, U.S. Army Corp of Entingeers, Bureau of Reclaimation), *Climate and Hydrology Datasets for use in the RMJOC Agencies' Longer-Term Planning Studies, 2011*

3.2 Flood Control

3.2.1 Called Upon Flood Control

As of September 2024, Canadian flood control commitments to the U.S. will be limited to an ad hoc "Called Upon"[11] approach, as set out in the Treaty. The U.S will also have to pay the Canadian operating costs and economic losses for each Called Upon request. These Treaty provisions are not well defined and there is substantial disagreement between the two Entities on their interpretation. After 2024, the U.S. will have to first make effective use of its reservoirs before 'calling upon' Canada to provide flood control space; this obligation exists whether the Treaty continues or is terminated.

Flood damage risks continue well into June as even average water years have the potential to develop into large peak flow years due to precipitation and high temperatures that may come late in the spring. The USACE's own extensive modeling[12] to quantify flood risk shows that the risk of flooding is greater post-2024 than pre-2024, even with the advantageous assumptions of Called Upon made by the USACE (which British Columbia disagrees with). Maintaining the same level of risk essentially requires having a similar amount of flood control space available in Canadian reservoirs pre- and post-2024, and the ability to direct refill of Canadian storage when required. The U.S. view of Called Upon Flood Control won't ensure the same level of risk as compared to pre-2024 and yet would still require significant changes to operations at U.S. reservoirs that would likely impact multiple water uses in the U.S. British Columbia's view is that Called Upon Flood Control may be able to provide the same level of flood risk to the U.S. by using all the smaller U.S. reservoirs on the Columbia, Snake and other tributaries. Such operation would likely impact multiple water uses on these smaller reservoirs.

The Province of British Columbia believes that there are more efficient ways to manage flood risk than the default and that Called Upon Flood Control is a step backwards. Under this flood control regime, the U.S. must make effective use of "all related storage in the United States"[13] before seeking additional help from Canada. This means that U.S. reservoirs will have to draft deeper and more frequently than they currently do. This requirement will likely have significant impacts on U.S. interests such as fisheries, recreation, irrigation and potentially navigation. Effective use at Libby dam, which is located in Montana and resulted in the creation of the Koocanusa Reservoir which extends approximately 70 kilometers back into Canada, will also have impacts on Canadian interests, although it will also increase flood protection downstream in Canada.

The following sections describe the potential impacts of Called Upon Flood Control and the differing views between the Canadian and U.S. Entities.

Implications of Called Upon

Post-2024, even if the Treaty continues, the Canadian Treaty dams will no longer have to conform to the flood control rule curves under the Flood Control Operating Plan described in section 2.2.1 because of the shift to Called Upon Flood Control. This would allow the Canadian Entity to operate Canadian reservoirs very differently than they are currently even though the Treaty power draft would continue. The Treaty allows

[11] The Treaty does not explicitly use the terms "Called Upon" and "On-Call" for the ad hoc flood control provided under the Treaty for post-2024 and pre-2024, respectively. Instead this has become established terminology used by the Canadian and U.S. Entities.
[12] Flood Risk Analysis – Iteration 2 Results (http://www.crt2014-2024review.gov/PowerPoint.aspx)
[13] Columbia River Treaty Protocol section 1.(2)

Canada the flexibility to move water between the different Canadian Treaty dams as long as the total power draft remains the same. This flexibility increases without the current flood control rule curves which expire in 2024.

In particular, to maximize domestic power production, Arrow Lakes Reservoir could be kept at a high, more stable elevation; consequently the storage space in Arrow Lakes Reservoir for flood control that the USACE currently relies upon would not be immediately available. Arrow Lakes Reservoir is particularly important for U.S. flood control because it takes only four days for flow releases from Arrow to reach the lower Columbia. Four days is within the forecasting timeframe so Arrow, along with Grand Coulee, can be used to manage flows during flood events. Water from headwater reservoirs such as Mica Dam and Hungry Horse have longer travel times.

In the longer term, all dams require significant capital investment and maintenance which can be significantly higher than the initial capital cost of the project. An evaluation of the small amount of power generation and the potential cost of major upgrades to Hugh Keenleyside Dam might lead to different operations or physical configurations than are currently modelled if the Treaty is terminated. This along with potential water licensing changes (i.e. changes in allowable minimum and maximum elevations) should the Treaty be terminated, could affect the storage available under post-2024 Called Upon Flood Control. Although Called Upon Flood Control continues regardless of whether the Treaty continues or is terminated, this obligation only extends for the life of the Treaty dams and there is no requirement for Canada to maintain the same amount of storage.

Called Upon Rights and Obligations

The Canadian[14] and U.S.[15] Entities have differing views on the rights and obligations related to Called Upon Flood Control. Each Entity has published a paper describing their positions. The respective views differ primarily over:

1) the forecasted peak flow at The Dalles that may trigger a Called Upon Flood Control request; and
2) which U.S. reservoirs must be used to provide effective use flood control.

British Columbia's view is that Called Upon Flood Control could only be used when forecasts of potential floods indicate there is a reasonable risk of exceeding 600,000 cfs at The Dalles. Based on this flow target, Called Upon Flood Control is expected to be used infrequently and only in very large snow pack years when effective use of all U.S. storage will be unable to maintain flows at The Dalles below 600,000 cfs. Called Upon Flood Control is not a mechanism to transfer the responsibility of managing the risk of changing or inaccurate forecasts from U.S. storage to Canadian storage.

For the U.S. to be eligible to call upon Canada for flood control assistance after 2024, the U.S. must first plan for, and use, to the extent necessary all available U.S. storage that can contribute to providing U.S. flood protection ('effective use'). This effective use requirement will result in changes to the current operations of

[14] Canadian Entity, *Canadian Entity View of Columbia River Post-2024 Called Upon Procedure.* February 14, 2013 http://blog.gov.bc.ca/columbiarivertreaty/files/2012/07/130214-CanadianEntity_View_CRT_Post-2024_CU-FINAL4.pdf

[15] U.S. Army Corp of Engineers, *White Paper on Columbia River Post-2024 Flood Risk Management Procedure*. September 2011.

U.S. reservoirs. The U.S. reservoirs will be drawn deeper more frequently and will result in risk and occurrences of not being able to meet refill targets. U.S. studies have demonstrated that this may create impacts primarily to fisheries; however other interests are also being examined, such as water supply and irrigation, recreation and navigation. The U.S. Entity's view that flows of 450,000 cfs at the Dalles are the trigger for Called Upon Flood Control means that the impacts of effective use would be more frequent.

This effective use requirement leads to the second area of disagreement between the Entities with regards to the implementation of Called Upon Flood Control. Effective use requires that the "...U.S. will call upon Canada to operate [Canadian storage] only to control potential floods in the U.S. that could not be adequately controlled by *all the related storage facilities in the U.S."* British Columbia interprets this provision to mean that if a facility can be effective in reducing flows at The Dalles it should be part of the effective use requirement before calling upon Canada.

To date, U.S. studies have been limited to a small number of headwater projects (Libby, Dworshak, Hungry Horse, Brownlee) and Grand Coulee. BC Hydro has conducted a preliminary analysis to determine the ability of smaller U.S. reservoirs on the Columbia main stem and tributaries to reduce flows at The Dalles. The results show that drafting other U.S. projects can be effective in reducing peak flood volumes as required by the Protocol. U.S. flood control operations, therefore, would need to include many additional projects such as Chief Joseph, Wells, the five mid-Columbia facilities (as was provided pre-1970), McNary, John Day, The Dalles, and Lower and Upper Snake dams. BC Hydro analysis estimated U.S. energy losses due to effective use at these facilities (in a Called Upon year) to be approximately 1,300-3,000 gigawatt hours with an estimated value of $40 to $150 million. Other potential adverse impacts on fisheries, recreation, irrigation and navigation interests have not yet been evaluated.

<u>Winter Flood Events</u>

Called Upon Flood Control is impractical for dealing with winter flood events. Unlike spring flood events, which are mainly snowmelt driven and can be planned months in advance based on inflow forecasts, winter flood events tend occur due to intense rain events which are less predictable and more immediate. It is unclear how the U.S. could operate to show effective use of their facilities in these instances. The U.S. Entity has not yet put forward a plausible approach for addressing these issues.

3.2.2 Coordinated Flood Risk Management

Canadian storage is valuable in mitigating risk of flooding in the U.S., and it is British Columbia's view that to maintain the same level of flood risk post-2024, the U.S. should be interested in more coordination with Canada, not less.

Continuing the Treaty would provide the U.S. with a greater ability to manage flood risk even under a Called Upon flood control regime, as the U.S. will be able to rely on information on the coordinated and assured Canadian power draft and a forecast of the planned Canadian reservoir operations throughout the year. However, the U.S. view of Called Upon may not protect U.S. locations to the same level of flood risk pre- and post-2024 as previously discussed. Potential climate change scenarios may also increase the flood risk, especially with respect to more frequent extreme weather events.

British Columbia believes that working collaboratively within the Treaty framework, the U.S. and Canadian Entities can find a solution to the problems brought about by the change in flood control regime post-2024, and seek an agreement to supplement Called Upon Flood Control that will not have undue adverse impacts on other interests. Mechanisms for addressing winter storms are also possible. Outside of the Treaty framework, such agreement would be much harder and more costly to achieve, if not impossible.

3.3 Power Production and Reliability

During the Treaty review, BPA's power analyses have focused on average energy benefits (over a 70 year period) based on assumed Canadian operations, and the resulting information is presented in a way that could lead people to believe that the power benefit of continuing the Treaty is only 10% of the Canadian Entitlement. British Columbia believes that the value is much higher, and even exceeds what is currently returned to Canada. Framing the value question around the average cost of energy is missing a larger issue of fulfilling the core responsibility of utilities to provide reliable power at all times (for example, during periods of low flows). Reliability of the electrical system is important to BPA, and to the Public Utility Districts that share in the benefits of the coordination as well as share in the cost of the return of the Canadian Entitlement to Canada.

The importance of coordination to planning the whole Pacific Northwest system was already discussed in Section 2.2.2, which outlined how planning of up to 18 months in advance is required for reliable power supply and the ability to manage for other values. As mentioned in BPA's own documents, '*international cooperation is essential'*. Currently, certainty around Columbia River regulation from Canada for a given water condition is the backbone around which additional inflows and operations are coordinated throughout the downstream system. Terminating the Treaty would create significant uncertainty in downstream operations as Canadian operations would be unknown and could not be relied upon.

Utilities have a fundamental obligation to reliably meet their firm electrical load obligations. Reliability incorporates different components, including:

- Firm Energy: The fuel for the Federal Columbia River Power System (FCRPS) is water. The amount of available water depends upon the weather and varies greatly throughout the year and from year to year. Utilities must be able to meet their load obligation in prolonged dry periods that could extend over multiple years.
- Seasonality of loads: The system must be able to meet the load as it changes seasonally even during winter cold snaps when inflows are significantly reduced, and during dry hot summers when irrigation, fisheries, and recreation are all competing with power for water.
- Dependable Capacity: Sufficient capacity is required to reliably generate electricity at the instant it is required. As the balancing authority, BPA must provide sufficient reserve capacity to back up the high amount of wind and other intermittent energy sources connected to its system.
- Over supply and wind integration: Utilities must be able to shed generation when there is more generation than load. This is an increasing issue for the Pacific Northwest.

The Treaty provides assured winter flows, drafts in dry years to maintain the U.S. ability to meet its firm load during high demand and drafts in dry summers when U.S. inflows are reduced. As such, the Treaty plays a critical role in providing reliable power to the entire U.S. Pacific Northwest, even in drought conditions. The reliability and planning value of coordination is difficult to quantify as it provides benefits to purposes beyond power production. However British Columbia believes coordination is worth much more to the U.S. than the Canadian Entitlement, especially when all the risks to water supply, ecosystem, recreation, and navigation are also considered.

The following sections describe the value of the Treaty to the reliability of the power system. The first section, however, highlights the risk of assuming a Canadian operation will stay the same if the Treaty is terminated by describing different possible Canadian operations.

Potential operational changes

Under the terms of the Treaty, reservoirs are drafted in order to maximize power production. For example, Arrow Lakes Reservoir is drafted before Grand Coulee, and as a result, the very head-sensitive Grand Coulee hydro project is able to maintain a higher elevation in order to maximize power production.

Arrow Lakes Reservoir has the most potential of any of the Canadian reservoirs to change operations post 2024. Although it is a large storage facility (7.1 MAF), it has a relatively low head dam; the associated power plant (Arrow Lakes Generating Station) has only 185 megawatts of installed capacity. If the Treaty is terminated, an optimal power operation for Canada would keep this reservoir near full to maximize energy production. Essentially Arrow Lakes Reservoir could operate as a near run-of river facility with only a small draft for local Canadian flood control. This operation could release more water in spring but less in summer.

However, there are a number of domestic environmental and social interests around the Arrow Lakes Reservoir and the downstream river reach that could cause the reservoir to be operated much differently than an optimal Canadian power operation. For example, Arrow Lakes Reservoir could be operated at a much lower level to benefit vegetation and wildlife interests in the Revelstoke reach. Or, flow releases from Arrow Lakes Reservoir during the spawning period January to March could be minimized to reduce potential stranding of whitefish and trout eggs. Essentially, Arrow Lakes Reservoir could re-regulate the flows from Mica for environmental and social benefits in Canada. The U.S. would have to access their reliability needs without the assured winter flows under the Treaty.

If the Treaty is terminated, the Arrow Lakes Reservoir and other Canadian reservoirs would be operated solely for Canadian interests and would not be operated to provide downstream regulation for U.S. projects. Under these conditions, Grand Coulee would likely have to take on most of the responsibility for regulating the flows in the Columbia River in the U.S, especially for flood control. Deeper and more frequent drafts of Grand Coulee reservoir would be expected, with associated risks to refill and impacts on capacity and energy outputs as well as recreation, irrigation, and fisheries interests.

Furthermore, the information on Canadian operations that the U.S. could rely on for structuring its planned operations would be minimal as committing in advance to any set of operations would reduce Canadian flexibility without providing any Canadian gains. Except for emergency situations, little advance information on planned operations would likely be made available and communication would be similar to that between

Seattle City Light's Boundary Dam in the U.S. and BC Hydro's Seven Mile Dam immediately downstream in Canada on the Pend d'Oreille River.

Seasonal cold snaps

As discussed in section 2.2.2, seasonal cold snaps typically occur once or twice a winter, sometimes for extended periods. These cold snaps increase electrical demand and at the same time reduce the generation resources available to meet the load.

As long as the Treaty continues, the reduction in U.S. inflows (and generation) is countered by a corresponding increase in Treaty storage releases needed to maintain the U.S. Pacific Northwest firm energy load carrying capability. The assured release of water under the Treaty in the winter provides reliability in the Pacific Northwest. For example, in comparing the Treaty operations to the BC Hydro reference case in the Treaty Terminate scenario[16], the Treaty provides a 1.5 to 3.0 MAF draft of water during January/February of the lowest water years. This would provide approximately 1,500 to 3,000 GWh of additional U.S. generation during those months.

In addition, the Non-Treaty Storage Agreement can and has been utilized to release more water from Canadian storage and increase U.S. generation during a cold snap. In the absence of the Treaty, both of these reliable water augmentation mechanisms would be lost. Power utilities in the region would need to purchase generation at a time when other regions may also be experiencing increased demand. Alternatively, U.S. utilities may need to build additional winter peaking capacity to ensure reliability.

Seasonal and extended dry periods

As described previously, the Treaty provides for proportional summer draft in long dry summers to maintain reliability for customers by drafting Canadian storage before Grand Coulee, whereby Grand Coulee Reservoir is able to stay at a higher elevation than it would if Canada operated in its own self-interest to maximize power production and provide additional benefits to recreation, navigation and other Canadian interests. These conditions may become more prevalent as climate change predictions indicate that the southern Columbia Basin is expected to become hotter and dryer over time with prolonged dry water sequences.

In the U.S. Entity Iteration 1 studies for the Columbia River Treaty Review, U.S. generation was analyzed with continued Treaty coordination post-2024, and compared to U.S. generation that would result from flows derived from an assumed Canadian operation with "optimal" Canadian power generation.

In 20% of the years with the lowest water conditions, the U.S. losses in generation from uncoordinated operations was more than 1,000 aMW or 1,460 GWh over the months of August and September. This would be greater in an extreme dry year. Such a loss may result in the need to build new generation or force purchase of electricity from the wholesale market at the prevailing rate. Market prices for power in the Pacific Northwest tend to be higher in dry periods due to greatly-reduced hydro power generation.

Dry periods can extend over multiple years. When there are a number of low water years in a row, the Canadian Treaty storage does not refill each year. Even under these conditions, the Treaty requires additional water to be released from Canadian storage to supplement the low flows in the U.S. in order to maintain the

[16] BC Hydro, Columbia River Treaty Review Technical Studies [Draft], March 11, 2013

system's ability to meet the firm load. In these drought years, Canadian out-flow is greater than the in-flow and up to 15.5 MAF of the Treaty storage and up to 5 MAF of the Non-Treaty storage[17] can be used as long as the Treaty continues. If the Treaty was terminated, the contrary might occur in that Canadian outflow may not be greater than Canadian inflow in dry years as water may be retained in Canada to enhance Canadian refill and other Canadian interests.

The U.S. relies on these water augmentation mechanisms built into the Treaty to supplement flows in dry years. The load–resource balance that BPA publishes[18], which is used by the entire U.S. Pacific Northwest region for planning, assumes this supplemental flow from Canada in dry years.

In addition, due to fisheries constraints, the U.S. power system is now operated to a one year critical period based on 1937, which was the driest historical year. U.S. reservoirs have to refill in order to have enough water to be used for spring and summer fisheries flows. As a result, U.S. reservoirs are no longer used to shift water from a wetter year to a drier year.

Canadian storage under the Treaty and NTSA are the only mechanisms the U.S. has to supplement flows in multi-year droughts. Without these assured mechanisms, the U.S. utilities would likely re-examine their reliability planning criteria and the Pacific Northwest system firm energy load carrying capability. Additional resources may be required to meet the Pacific Northwest utilities firm load commitments.

Climate change predictions may exacerbate seasonal and extended dry climatic conditions as the downstream half of the Columbia Basin is anticipated to become drier and hotter over time and prolonged dry water conditions could increase in frequency.

Wind integration and over supply in the U.S. Pacific Northwest

Over the last five years, installed wind generation capacity has increased to over 4,000 MW causing over supply to become a chronic problem during the freshet period (April through July). Over supply occurs when the minimum hydroelectric generation combined with wind generation exceeds the demand. In this situation generation must be curtailed (water spilled or wind turbines idled) to maintain the stability of the power grid. There are, however, limits to how much water can be spilled past the generators at U.S. dams on the Columbia because spilling water raises the total dissolved gas in the water to levels that can be damaging to fish. BPA has an Overgeneration Management Protocol to turn down wind generation in over supply situations. The costs are currently shared 50/50 between BPA and the wind power producers. For 2013, if water conditions are average, the oversupply is estimated to be 283 MW-months with displacement costs of $10 million[19].

When there is an oversupply of electricity the market prices can become negative, and producers actually pay buyers to absorb the excess energy. In 2012 the light load hour prices were negative for 60% of the time April through July. The NTSA is being used to reduce the amount of surplus generation. In 2012, 2.8 MAF of water was stored under the NTSA from April through July. If this water had not been stored during the spring months, another 4,000 MW-months (approximately $40-60 million) would have been generated (or spilled) at

[17] The current expected use of non-Treaty Storage is not to support Firm Energy Load Carrying Capability in the U.S. as the US Entity uses the agreement to support fisheries operations and shape energy into higher value periods. However, under extreme conditions it is possible that the U.S. priorities change, and the Non-Treaty storage provides some backup or insurance.
[18] Bonneville Power Administration, Pacific Northwest Loads and Resources Study (2012 White Book) https://www.bpa.gov/power/pgp/planning.shtml
[19] www.nwcouncil.org/media/5729978/3.pdf

the U.S. dams, causing additional wind displacement and/or additional fisheries issues related to total dissolved gas. The NTSA and the Treaty both provide mechanisms for reducing the amount of wind displacement required.

3.4 Ecosystem

As noted in section 2.2.3, coordination of reservoir operations and subsequent flows under the Treaty have expanded coordinated operations beyond power production and flood control to include ecosystem objectives. This is accomplished through a number of actions, including proportional drafting during annual low flow periods to provide extra flows during late summer, Supplementary Operating Agreements that provide higher flows during the freshet to assist with fish recovery, and dry year strategies as part of the NTSA.

During the dry summer period, coastal and interior rivers that are either rainfall driven or have little snow accumulation tend to dry up and may reach their annual low flows in August or September. Flows on the Columbia River main stem are primarily maintained from the snow and glacier melt at high elevations in Canada and parts of the U.S. basin. In low snow pack years, the natural inflow in late summer is considerably less. For example, at McNary dam, where the summer flow objective for fisheries is 200,000 cfs, the unregulated flow drops below this level on average by the end of July and reaches 100,000 cfs by the third week in August.

If the Treaty is terminated, Canadian reservoirs would be managed for Canadian interests: domestic fish operations could have priority in some months; recreation interests could take priority in summer; bird and wildlife or cultural heritage could take priority in other times of the year. Different combinations of priorities in Canada could change under different water conditions and also change over time to adapt to changing climate conditions. A degree of balance between different domestic values and interests was achieved during the Columbia River Water Use Planning process in B.C. However, during that process the existence of the Treaty constrained the flexibility of operations to meet some important domestic objectives. It is not possible at this time to predict what may result from a future Water Use Plan that would not be constrained by Treaty requirements. If notice of Treaty termination is given, changes to the current operating regime would be explored in the next Water Use Plan review scheduled for 2021.

Treaty termination would likely have a significant impact to U.S. fisheries operations under low flow conditions which could be exacerbated by climate change in the Basin. There are a number of significant benefits to U.S. fisheries that would be lost by Treaty termination. These include:

- <u>Proportional Drafting:</u> Due to power provisions of the Treaty the coordinated system moves into proportional draft in low water conditions. The Canadian reservoirs draft to maximize electrical generation in the system, which in turn provides water for U.S. fisheries operations, especially in dry years and dry summers. Cold water flows from Canada in late summer support fish survival and spawning, especially during low flow years. While the Canadian reservoirs need to comply with proportional draft requirements under the Treaty, U.S. operations have the flexibility to manage flows for a variety of competing interests once the water crosses the border.

- Non-Power Uses Agreement: The U.S. relies on this water augmentation mechanism to supplement flows for fisheries purposes. Currently, 1 MAF of flow augmentation under the agreement moves water from January/February to June/July to more closely replicate portions of the natural hydrograph. US Entity studies have modelled ecosystem components that would require further coordination with Canada. Both present and potential future ecosystem enhancements would require similar or greater coordination that could only occur under the Treaty.
- Non-Treaty Storage Agreement: The NTSA is particularly valuable for U.S. salmon interests as the dry year release provision guarantees a right to the U.S. to release 0.5 MAF for use in May/June to support salmon migration in the lower Columbia River during the driest 20% of runoff years. It should be noted that the U.S. Entity analysis to date has not included the impacts from the loss of coordination under the NTSA, provisions of which would not continue under Treaty termination.

In addition, U.S. fisheries may be significantly impacted by the current default post-2024 flood control operation, which will change the operation of all U.S. reservoirs. As explained in section 3.1.1, Called Upon Flood Control will require U.S. reservoirs to be drafted deeper more frequently, which would likely affect a range of ecosystem and other values. Currently, in the spring, the U.S. operates many of its reservoirs to the upper flood control level to provide more water in spring and summer for fisheries. With the requirement starting in 2024 for the U.S. to first make effective use of its reservoirs for flood control, more water would be discharged in winter to draft the reservoirs deeper than is current practice and therefore having less water to release in the spring. This would increase the risk of reservoirs not being able to refill, and subsequently result in less water available for fisheries in the summer. If the Treaty continues British Columbia is open to discussing incremental flood risk management arrangements that could avoid these impacts.

It is useful to note that BPA's investments in fisheries recovery are many times higher than the value of the Canadian Entitlement under the Treaty. On average, BPA alone spends approximately $700 million per year on fish and wildlife enhancements in the Basin. Of those total expenditures, an annual average of $180 million was as a result of power losses by reregulating of power flows for fish. These are only some of the investments being made in ecosystem mitigation and restoration as other U.S. agencies, Tribes, power utilities, and non-profits are also dedicating significant resources to enhance environmental values. It may not be cost effective for the U.S. to pursue the reduction or elimination of the Canadian Entitlement payments if the resulting uncertain river flows and lack of coordination during low flow periods undermine the more costly investments in fish survival.

3.5 Water Supply

During the dry summer period, coastal and interior rivers that are either rainfall driven or have little snow accumulation tend to dry up and may reach their annual low flows in July to September. Throughout these months there is heightened competition in the U.S. for limited water resources. Future decisions regarding the Treaty may significantly affect water supply to a range of stakeholders in downstream states. The most significant potential causes of change are the effective use of U.S. reservoirs for flood control and the loss of flow augmentation and proportional draft.

As explained in section 3.1.1 the change in the flood control regime in 2024 to Called Upon Flood Control will require the U.S. to make effective use of U.S. reservoirs to minimize flood risk prior to calling upon Canada for assistance by providing additional storage. This means that U.S. reservoirs will need to be drawn down deeper and more frequently than they are currently because reliance on planned Canadian reservoir space will no longer be possible. Furthermore, as risks of changing or inaccurate inflow predictions transfer from Canadian reservoirs to U.S. reservoirs, corresponding risk of reservoirs not achieving refill is increased. Consequently, predictability in the availability of storage water for water users would be decreased, and for irrigators, pumping costs may increase with lower reservoir levels. B.C. maintains that the Called Upon Flood Control regime is a step backwards that does not serve either country well and is open to discussing mutually beneficial arrangements.

Treaty termination would produce negative consequences to U.S. water supply during low flow periods and years. Previous sections on post-2024 power production and ecosystems describe mechanisms under the Treaty and the NTSA that augment flows during seasonal low flow periods and during the 20% lowest flow years. These supplemental flows would no longer be available if coordination under the Treaty is discontinued. In short, without the cooperation set out in the Treaty between the two countries, reservoir levels and flows will likely be significantly changed from their current conditions. Climate change predictions of lower U.S. Columbia inflows and hotter, drier summers will only increase the need for collaboration. The impacts on water supply in the U.S. may be significant.

3.6 Navigation

The Columbia River is an important commercial waterway for the transportation of all types of goods and commodities from the region to domestic and international markets. Four main stem dams and four lower Snake River dams also contain navigation locks to allow ship and barge passage from the ocean as far as Lewiston, Idaho. The Columbia River has over 790 kilometers (485 miles) of navigable river and serves 36 ports and carries approximately 40% of all U.S. wheat. Over 35 million tons of cargo each year worth approximately $12 billion annually are exported and imported along the River.

Suppliers, traders and exporters all rely on low cost and dependable shipping conditions to be competitive on the world market. While Columbia River elevations experience seasonal adjustments which are anticipated, prolonged low or high water conditions may impact the safety and cost of navigation and port operations. In recent years, $50 million to $200 million has been spent annually on maintaining sufficient navigation channel depth, facilitating further port expansion, and supporting economic development.[20]

Changes that will be occurring because of the Treaty may significantly affect navigation and related interests. After 2024, the flood control operational regime will change from a predictable assured Flood Control operation to the ad-hoc Called Upon Flood Control that will increase the frequency of higher flows at The Dalles. Currently, Columbia Basin flood risk is managed collaboratively between both countries to reduce flood flows.

[20] Port of Vancouver letter to U.S. Entity February 12, 2013

Under the ad-hoc Called Upon Flood Control, forecasted Columbia River flows at The Dalles of 600 kcfs are needed before Canadian reservoirs can be called on to provide additional storage. This will increase the frequency of higher flows and could affect navigation and port operations, increasing shipping times and/or affecting docking operations. Higher flows may also increase the rate of erosion and sedimentation, affecting channel depths.

There are unresolved differences between the Canadian and U.S. Entities on the interpretation of Treaty requirements after 2024; however it is clear that a change to Called Upon Flood Control is a significant step back from the current Assured Flood Control regime. B.C. is open to discussing more effective flood risk management arrangements that could benefit both countries and prevent these adverse impacts.

Treaty coordination of water flows is especially beneficial to navigation in dry seasons and years. Under the Treaty, during low water conditions in the summer, water is released from Canadian reservoirs in order to optimize power on the entire system. If the Treaty is terminated, Canadian reservoirs would be managed purely for Canadian domestic interests and the proportional drafting, where water is released from Canadian reservoirs first, would no longer occur, meaning lower flows crossing the border.

Similarly, the NTSA augments flows to the U.S. in the driest 20% of years. This agreement is linked to the Treaty and would expire if the Treaty is terminated. In both low flow season and dry years, ceasing Canadian flow augmentation could impact available channel draft, disrupt transport and raise the risk of grounding.

4 BENEFITS OF THE TREATY AND COORDINATED FLOOD CONTROL

4.1 Benefits to the U.S.

The preceding chapters have outlined the Province of British Columbia's perspective on the benefits and risks to the U.S. if the Treaty is terminated as compared to continued coordination. Coordination with Canada has been shown to provide certainty for power planning for BPA, the Mid-C public utility districts and other power generators that provide the reliability required in meeting the electricity needs of power customers. During cold, dark winter periods when energy for heating and lighting is critical, or during the dry summer months when power production drops due to low river flows, supplementary water releases from Canada under the Treaty reduce the risk of curtailing load. In 1 in 5 years when the Basin is driest, the NTSA dry year strategy provides incremental flows to meet summer demand.

Other interests and stakeholders benefit from the Treaty as well. U.S. fisheries programs, including legal requirements to meet salmon recovery objectives, have made billions of dollars in investments to support these goals. Treaty coordination is contributing to ecosystem recovery and enhancement plans through proportional drafts and flow augmentations from Canada during the spring freshets and low flow summer period and throughout dry years as well. At this stage no one can predict how terminating the Treaty may impact the sustainability of these fisheries values and protect previous and ongoing investments. However, collaboration between the two countries under the Treaty can only benefit ongoing efforts to address ecosystem needs in both countries.

Water supply managers in several states are under pressure to meet a variety of stakeholder demands. Trade-offs between interests, such as agriculture, recreation, domestic and industrial consumption, have become the

norm and conflict around these choices will only increase as a result of expected climatic change. If the Treaty is terminated, flows in Canada during critical dry periods will be managed for Canadian domestic interests. However, if the Treaty continues the two countries can continue an ongoing dialogue, in the spirit of the Treaty's founding principles of creating and sharing benefits equally, to address new challenges that were not contemplated in the 1960as when the Treaty was signed.

The Treaty has benefited U.S. communities by minimizing significant floods through planned coordinated operations, saving billions of dollars in flood damage in the U.S. The default change in flood control regime in 2024 prescribed by the Treaty whether it is terminated or not will likely impact all of the interests considered in this paper. Navigation, and the domestic and international commerce it supports, would be affected by higher flood flows that could disrupt marine traffic throughout the system, and would need to respond to infilling and shoaling at significant additional costs. The use of U.S. storage that would see reservoirs drafted deeper and more frequently with more refill failures could affect all the interests discussed earlier: fisheries, agriculture, navigation, recreation water supply, and power production. The Province believes the current level of flood control can best be re-negotiated from within the structure of the current Treaty.

While quantifying all of the benefits of the Treaty and the risks and losses if the Treaty is terminated is beyond the scope of this paper, it is clear that current social and environmental expectations extend far beyond just flood protection and power production.

4.2 Benefits to Canada

British Columbia does not face the same water resource pressures as the U.S. BC has sufficient available reservoir storage to manage flows to protect communities from significant floods and there is ample water supply for agriculture, domestic consumption and industrial uses. B.C.'s ability to balance recreation, ecosystem and power production interests are only limited by the Treaty.

Treaty constraints and requirements on Canadian reservoirs continue to impact environmental, social and economic values in British Columbia. While the U.S. Entity has the freedom and flexibility to manage Treaty flows south of the border for a variety of domestic interests, the Canadian Entity does not have that flexibility due to operations required under the Treaty. Citizens in the Canadian Columbia Basin continue to raise the issue of imbalance between historic and ongoing impacts of the Treaty facilities and their operations and the share of benefits to the Province of British Columbia.

The only benefit to Canada from the Treaty is through the return of the Canadian Entitlement. The Canadian Entitlement is an estimated calculation of half of the potential increase in power production in the U.S. as a result of coordination under the Treaty. The Canadian Entitlement is returned to B.C. in the form of energy at the border. The revenue from the sale of the energy on the market becomes part of the general revenue to the Province. While historically annual revenues from the sale of the Canadian Entitlement have been approximately $200 million on average, current market prices have been depressed in recent years meaning that the Canadian Entitlement has been worth $100-150 million per year. The size of the Canadian Entitlement is forecasted to decrease over time.

While the U.S. has chosen to trade-off some of its potential downstream power benefits from the Treaty for more valuable benefits, it is British Columbia's view that, given the benefits and the avoidance of losses and risks described throughout this paper, the U.S. benefits more from the Treaty than does Canada. The Province of British Columbia is of the view that Canada should not bear the financial burden of the choices that the U.S. has made to regulate water for other purposes beyond what was initially intended under the Treaty.

5 CONCLUSION

There appears to be a misconception by residents on both sides of the border that the Treaty can be terminated and easily renegotiated for more benefits to Canada, or more benefits to the U. S., depending on which side of the border one lives. The original Treaty took twenty years to negotiate during a simpler time when fewer values were considered and with no consultation. Today's world is much more complex than it was in the 1960's, government processes are more daunting, and it is unlikely that an entirely new Treaty could be developed. B.C. does not believe that a series of transboundary commercial agreements to replace the Treaty would be workable or desirable on such a large scale. The Treaty, however, provides for considerable flexibility and changes can be made at any time if both countries agree. Given this, British Columbia's position is that if the two countries cannot agree on changes within the Treaty framework, there is almost no hope that an entirely new Treaty could be negotiated.

The Columbia River Treaty has worked well for both Canada and the U. S. and has adapted to changing values over time. Citizens and stakeholders in both countries need to be fully informed on all the future costs, risks and benefits of alternatives in each country when seriously considering the future of the Treaty.

Contract No. 12PG-10002

COLUMBIA RIVER NON-TREATY STORAGE AGREEMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Table of Contents

Exhibit G **Transaction Request Protocol and Energy Scheduling Guidelines**
Exhibit H **Bridge Agreement Reconciliation**

This COLUMBIA RIVER NON-TREATY STORAGE AGREEMENT (Agreement) is executed by the BONNEVILLE POWER ADMINISTRATION (BPA) a departmental element of the United States, Department of Energy, and BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH) a Crown corporation of the Province of British Columbia, continued under the *Hydro and Power Authority Act,* R.S.B.C. 1996, c. 212, as amended. BPA and BCH are sometimes referred to individually as "Party" and collectively as "Parties."

RECITALS

Whereas BCH is engaged in the sale and delivery of electric power and energy to customers in British Columbia and is the owner of an electric generation, transmission and distribution system which is used by it to supply electric power and energy to such customers; and

Whereas BPA is authorized, pursuant to United States (U.S.) law to dispose of electric power generated at various federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority; and

Whereas the Governments of the United States of America and Canada, on September 16, 1964, ratified the Treaty between Canada and the United States of America Relating to Cooperative Development of the Water Resources of the Columbia River Basin signed at Washington on January 17, 1961, and by an Exchange of Notes dated January 22, 1964, the two Governments agreed upon the terms of a Protocol with effect from the date of the exchange of instruments of ratification of the aforesaid Treaty (which Treaty and Protocol are hereinafter referred to as the "Treaty"); and

Whereas BCH constructed Mica and Arrow dams (hereinafter referred to as "Mica" and "Arrow" respectively) pursuant to the Treaty providing approximately 7.0 million acre-feet of Treaty storage at Mica, and approximately 7.1 million acre-feet of Treaty storage at Arrow, and BCH is authorized to operate such storage; and

Whereas BCH constructed additional non-Treaty storage at Mica, which has provided additional flexibility and other benefits to both Parties; and

Whereas successive agreements executed between the Parties and relating to the initial filling of non-Treaty reservoirs and the use of Columbia River non-Treaty storage (BPA Contract No. DE-MS79-84BP90946 and DE-MS79-90BP92754) have expired and short-term, seasonal non-Treaty storage agreements have been reached between the Parties from 2006 through 2012; and

Whereas nothing in this Agreement is intended to supersede or amend the terms and requirements of the Treaty nor diminish BCH's entitlement to determine the operation of its facilities, including its reservoirs; and

Whereas the U.S. and Canadian Entities established under the Treaty have reviewed this Agreement and have, through a separate written agreement, concurred that operations under this Agreement will not adversely affect stream flow control in the Columbia River within Canada so as to reduce flood control and hydroelectric power benefits under the Treaty, pursuant to Article IV(5) of the Treaty; and

Whereas BPA and BCH enter into this Agreement with the shared purpose of obtaining additional operational flexibility and power and non-power benefits through the coordination of flow operations;

Now therefore the Parties agree as follows:

1. TERM

This Agreement shall take effect upon the latest date of execution by both Parties. Subject to Sections 23 and 24, this Agreement shall expire at 2400 hours on September 15, 2024.

2. DEFINITIONS

In this Agreement, the following words and terms shall have the meanings stated below, unless the context otherwise requires. Capitalized terms that are not listed below are defined within the section in which the term is used. Words in the singular include the plural and vice versa, as context requires. Where a value is quoted in both cubic kilometers (km^3) and million acre-feet (MAF), or both cubic meters per second (m^3/s) and thousand cubic feet per second (kcfs), the units of MAF and kcfs shall be used and shall be determinative for the purpose of making calculations under this Agreement.

(a) "Active Account" shall have the meaning as described in Section 3(a).

(b) "Available Energy Balance" means the value of energy deliveries a Party may request in accordance with Section 6(c) and determined as described in Exhibit F, Determination of Available Energy Balance.

(c) "BCH Critical Planning Period" means the period in the historical stream flow record during which the water available from reservoir releases plus the natural stream flow is capable of producing the least amount of hydroelectric power in meeting system load requirements.

(d) "BCH Dry Period Conditions" means the water conditions occurring when system unregulated inflow volume for the previous February through September are as low as, or lower than the highest February through September inflow volume occurring within the BCH Critical Planning Period, as determined through BC Hydro long term planning models. As of the Effective Date, this threshold system inflow volume is estimated at 90% of normal using the 1981 to 2010 period of record, which may be updated

periodically by BC Hydro, for the February through September period. Average system unregulated inflows are documented in the official Water Supply Summary, published by BCH in October of each year and shared with Provincial government agencies.

(e) "BCH Dry Period Operation" shall have the meaning as described in Section 8(a).

(f) "BPA Dry Period Conditions" means water conditions in a year that are in the lowest 20th percentile based on the Northwest River Forecast Center's (NWRFC) volume runoff averages for their statistical period of record as defined in the 2010 Federal Columbia River Power System (FCRPS) Biological Opinion, or its successor or replacement document that captures such information, as determined in accordance with Section 9(a).

(g) "BPA Dry Period Operation" shall have the meaning as described in Section 9(b).

(h) "Bridge Agreement" means the Non Treaty Storage Short-Term Bridge Agreement, Contract No. 11PB-21385.

(i) "Delivery Point" means the Canada-U.S. border at British Columbia or such other delivery point as is mutually agreed to by the Parties.

(j) "Detailed Operating Plan" means the detailed hydroelectric operating plan prepared annually for the August through July period, in accordance with Article XIV of the Treaty.

(k) "Downstream Federal Hydro Projects" means the six federal hydroelectric generating facilities on the Columbia River in the United States: Grand Coulee, Chief Joseph, McNary, John Day, The Dalles and Bonneville.

(l) "Downstream Mid-C Hydro Projects" means the five non-federal Mid-Columbia (Mid-C) hydroelectric generating facilities on the Columbia River in the United States: Wells, Rock Island, Rocky Reach, Wanapum, and Priest Rapids.

(m) "Downstream U.S. Hydro Projects" means the Downstream Federal Hydro Projects plus the Downstream Mid-C Hydro Projects.

(n) "Effective Date" means the date on which this Agreement takes effect as described in Section 1.

(o) "Energy Price" means the price per megawatt-hour (MWh) of energy in U.S. dollars as determined consistent with Exhibit B, Energy Pricing.

(p) "Expiration Date" means the date on which this Agreement expires as described in Section 1.

(q) "Federal h/k" means the daily average rate in megawatts (MW) per kcfs at which water can be or could have been converted into energy, including adjustments for spill, at the Downstream Federal Hydro Projects, as calculated in accordance with Exhibit A, Daily Conversion Factors (h/k) Calculation.

(r) "Head Loss Energy" means the energy associated with BPA's share of head losses on the BCH system, as calculated in accordance with Section 7.

(s) "Heavy Load Hours" or "HLH" shall have the meaning as defined in Exhibit B, Energy Pricing.

(t) "Initial Water Balance" shall have the meaning as described in Section 3(a)(2) and Section 3(b)(2) for the Active Accounts and Recallable Accounts, respectively.

(u) "Light Load Hours" or "LLH" shall have the meaning as defined in Exhibit B, Energy Pricing.

(v) "Mid-C Participant" means an owner and/or operator of any of the Downstream Mid-C Hydro Projects: Public Utility District No. 1 of Chelan County, Washington (Rock Island and Rocky Reach Projects); Public Utility District No. 1 of Douglas County, Washington (Wells Project); and Public Utility District No. 2 of Grant County, Washington (Wanapum and Priest Rapids) and other parties that receive a share of the output from one or more of the Downstream Mid-C Hydro Projects.

(w) "Recallable Account" shall have the meaning as described in Section 3(b).

(x) "Transaction Benefit Account" shall have the meaning as described in Section 6(b).

(y) "Transaction Request Protocol" means the procedures for making and responding to Transaction requests, as set out in Exhibit G, Transaction Request Protocol and Energy Scheduling Guidelines.

(z) "Treaty Storage Regulation Study" means the coordinated system hydro regulation study prepared in accordance with the Detailed Operating Plan.

(aa) "Treaty Week" means the one-week period covered by the Weekly Treaty Storage Operation Agreement as defined in the Detailed Operating Plan, currently Saturday through Friday.

(bb) "U.S. h/k" means the daily average rate in MW per kcfs at which Non-Treaty Water Transactions can be or could have been converted into energy, including adjustments for spill, at the Downstream U.S. Hydro Projects, as calculated in accordance with Exhibit A, Daily Conversion Factors (h/k) Calculation.

(cc) "Water Transaction" means the change in outflow at Arrow resulting from requests made under this Agreement with respect to the volume of water in the Parties' respective Active Accounts or Recallable Accounts.

3. ESTABLISHMENT AND AVAILABILITY OF COLUMBIA RIVER NON-TREATY ACCOUNTS

On the Effective Date, BCH shall establish and make available the following non-Treaty accounts totaling 6.17 km^3 (5.0 MAF), in accordance with the following:

(a) **Active Accounts**

In accordance with and subject to the terms of this Agreement:

(1) BCH shall establish an Active Account for each Party with an account limit of 1.85 km^3 (1.5 MAF), which shall remain available for use by the Party during the term of the Agreement.

(2) The Initial Water Balance in each Party's Active Account shall be set equal to 1.85 km^3 (1.5 MAF).

(b) **Recallable Accounts**

In accordance with and subject to the terms of this Agreement:

(1) BCH shall establish a Recallable Account for each Party with an account limit of 1.233 km^3 (1.0 MAF), which BC Hydro may make available for use by the Parties over the term of the Agreement.

(2) The Initial Water Balance in each Party's Recallable Account shall be set equal to 0.93 km^3 (0.75 MAF).

(c) **Activation of Recallable Accounts**

At any time during the term of this Agreement, either Party may request access to its Recallable Account, and BCH may, in its sole discretion and with as much advance written notice as is reasonably practicable, declare some or all of the Recallable Accounts available for use by the Parties. Subject to Section 8, BCH Dry Period Provisions and Section 13, Forced Evacuation of Non-Treaty Accounts, if the Recallable Accounts are declared available by BCH, then:

(1) the Recallable Accounts shall be made available for use by the Parties in equal amounts, unless otherwise agreed;

(2) the terms and conditions of use of the Recallable Accounts shall be as agreed by the Parties; and

(3) either Party may request a Water Transaction from its Recallable Account in accordance with and subject to Section 4, Water Transactions.

4. WATER TRANSACTIONS

Subject to Section 5, Displacement of Active Account Balances; Section 8, BCH Dry Period Provisions; Section 9, BPA Dry Period Provisions; and Section 13, Forced Evacuation of Non-Treaty Accounts, the terms and conditions of Water Transaction requests outlined in this Section 4 shall apply to all Water Transactions under this Agreement.

(a) **Water Transaction Requests**

In accordance with Exhibit G, Transaction Request Protocol and Energy Scheduling Guidelines, either Party may request a Water Transaction for the upcoming Treaty Week. In such request, the requesting Party shall: (1) designate a Water Transaction in respect of either its Active Account or, if declared available by BCH, the Party's Recallable Account and (2) specify if it is exercising its rights under Sections 5, 8 or 9. Subject to Section 13, a request shall not be required for forced evacuation. The priority of Water Transaction requests shall be in accordance with Section 12.

(b) **Account Limits**

A Party shall not request a Water Transaction that would: (1) reduce the balance of its Active Account or Recallable Account to less than zero, or (2) increase the balance of its Recallable Account to more than 1.233 km^3 (1.0 MAF).

A Party may request a Water Transaction that would increase the balance of its Active Account to more than 1.85 km^3 (1.5 MAF); provided, however, that the total balance of the Active Accounts shall not exceed 3.70 km^3 (3.0 MAF). If the Parties agree to such a Water Transaction, then the terms and conditions of Section 5, Displacement of Active Account Balances, shall apply.

(c) **Declining a Water Transaction Request**

Subject to Section 5, Displacement of Active Account Balances, Section 8, BCH Dry Period Provisions and Section 9, BPA Dry Period Provisions, either Party has the right to decline a Water Transaction request made by the other Party. However, each Party shall make reasonable efforts to accommodate Water Transactions requested under this Section 4 by the other Party.

The Parties recognize there are numerous constraints, including power and non-power requirements, upon system operations that may limit the ability of a Party to accommodate a Water Transaction request by the other Party. To promote a better understanding of each Party's non-power requirements and the resulting impacts on coordinating operations under this Agreement, a non-exhaustive listing of typical non-power requirements that the Parties recognize may limit operational flexibility is set out in Exhibit E, Potential Operational Limitations on NTSA Transactions.

(d) **Changes to Arrow Outflows**

Water Transactions under this Agreement for each Treaty Week shall be implemented by BCH by adjusting the outflow at Arrow to achieve a uniform flow rate for these Water Transactions over the applicable Treaty Week that

corresponds to the sum of the Parties' Water Transactions, unless the Parties agree to a mid-week change under Section 4(e).

(e) **Mid-week Changes**
Either Party may request a mid-week Water Transaction, if no request has been made for that week, or a mid-week modification to an existing Water Transaction (each, a Mid-Week Change) in situations including, but not limited to the following:

(1) by Monday of the Treaty Week, if the weekly average Federal h/k estimate has changed from the estimate made at the time of the Water Transaction request by fifteen percent (15 %) or more, higher or lower; or

(2) the Treaty Storage Regulation Study changes such that it will result in a significant change to Treaty outflows at Arrow from what was expected and planned for by a Party at the time of making its Water Transaction request.

A Party's request for a Mid-Week Change as a result of (1) or (2) above shall not be unreasonably denied by the other Party. All other Mid-Week Changes shall be made by mutual agreement of the Parties.

(f) **Water Transaction Accounting**
Accounting of Water Transactions made pursuant to this Section 4 shall be completed in accordance with Section 6, Water Transaction Accounting, Energy Accounting, and Energy Deliveries, except that accounting for Water Transactions made pursuant to Section 8, BCH Dry Period Provisions, shall be completed in accordance with Section 8.

5. DISPLACEMENT OF ACTIVE ACCOUNT BALANCES

If the Parties agree to a Water Transaction that would increase a Party's Active Account balance to more than 1.85 km^3 (1.5 MAF), then any volume of water in the Active Account of that Party (Overfilled Party) exceeding 1.85 km^3 (1.5 MAF) shall be subject to displacement by the other Party (Displacing Party) in accordance with the following:

(a) A Water Transaction storage request to displace an Active Account balance pursuant to this Section 5 shall be made in accordance with Section 4(a). Such storage request shall be limited by the lesser of:

(1) the Overfilled Party's Active Account balance in excess of 1.85 km^3 (1.5 MAF) expressed as a uniform flow rate over the applicable Treaty Week (in kcfs); or

(2) the volume of water required to achieve a uniform flow rate of 5.0 kcfs over the applicable Treaty Week.

The Overfilled Party shall not deny the Displacing Party's Water Transaction request.

(b) The Overfilled Party shall be deemed to have requested a corresponding Water Transaction release equal to the Water Transaction by the Displacing Party under Section 5(a). The net change in Arrow outflows resulting from such corresponding Water Transactions shall be zero.

(c) Accounting of displacement Water Transactions made pursuant to this Section 5, and any associated energy accounting, shall be completed in accordance with Section 6.

6. WATER TRANSACTION ACCOUNTING, ENERGY ACCOUNTING, AND ENERGY DELIVERIES

(a) General Accounting and Verification

(1) BPA and BCH shall each be responsible for maintaining a daily accounting to include, but not be limited to, the following: Water Transactions; account balances for BPA and BCH Active and Recallable Accounts; Federal h/k or U.S. h/k as applicable; Energy Prices; energy values associated with BCH Water Transactions; BPA Head Loss Payments; account balances for the Transaction Benefit Account; energy deliveries; and any financial payments made pursuant to this Agreement by either Party to the other.

(2) As of the Effective Date, all account balances under the Bridge Agreement shall be transferred to account balances under this Agreement, in accordance with Exhibit H, Bridge Agreement Reconciliation.

(3) BPA and BCH shall verify and reconcile Water Transactions and energy accounting on a monthly basis.

(4) BCH may request information from BPA to verify the after-the-fact accuracy of the Federal h/k or, if applicable, U.S. h/k applied to a BCH Water Transaction, and BPA shall provide such information as soon as practicable following such request.

(b) Transaction Benefit Account

A Transaction Benefit Account shall be established and maintained under the Agreement by the Parties to track and account for the energy values associated with the transactions described below. A positive balance in the Transaction Benefit Account shall be deemed a value allocated to BCH, and a negative balance in the Transaction Benefit Account shall be deemed a value allocated to BPA.

(1) Energy values associated with BCH Water Transactions shall be tracked and accounted for in the Transaction Benefit Account, except

for BCH Water Transactions under Section 8, BCH Dry Period Provisions.

(2) There shall be no energy values associated with any BPA Water Transactions under this Agreement, except for energy values associated with head losses on the BCH system as described in Section 7, BPA Head Loss Payments, which shall be tracked and accounted for in the Transaction Benefit Account.

(3) The energy values associated with BCH Water Transactions in Section 6(b)(1) above shall be calculated as follows, on a daily basis:

(i) The energy associated with a BCH Water Transaction shall be calculated by multiplying the after-the-fact Federal h/k by the daily Water Transaction volume. BCH Water Transactions that reduce Arrow outflows shall be recorded as a negative volume and those that increase Arrow outflows shall be recorded as a positive volume.

(ii) The value of the energy in (i) above shall be calculated by multiplying the energy in MWh times the daily flat Energy Price for the day that the water is deemed to pass through the Downstream Federal Hydro Projects.

The Parties shall assume a 1-day lag between BCH Water Transactions and the resulting change in generation on the Downstream Federal Hydro Projects. Therefore, the Parties shall use Federal h/k and Energy Prices that are lagged by one day from the day of the BCH Water Transaction to calculate energy and energy value in (i) and (ii) above.

(c) **Energy Deliveries Based on the Transaction Benefit Account Balance**

(1) The Party with an Available Energy Balance in its favor, as determined in accordance with Exhibit F, may request energy deliveries from the other Party (Delivering Party) up to the value of the Available Energy Balance. Such requests shall be at a uniform hourly rate, up to 300 MW in Light Load Hours (LLH).

(2) The Delivering Party may not unreasonably deny an energy delivery request. It shall not be deemed unreasonable to deny the request if it is expected that the Energy Price for the applicable upcoming week will be less than or equal to zero, or if energy or capacity limitations would compromise the Delivering Party's ability to serve its load obligations. The Parties may mutually agree to alternate delivery schedules.

(3) Energy deliveries shall be scheduled pursuant to Section 11, Scheduling and Delivery of Energy and Exhibit G, Transaction Request Protocol and Energy Scheduling Guidelines.

(4) The value of the energy actually delivered shall be tracked and accounted for in the Transaction Benefit Account. Energy values will be calculated based on the Energy Price for the applicable time blocks, as described in Exhibit B, Energy Pricing, and delivered energy amounts. Energy deliveries from BPA to BCH shall be recorded in the Transaction Benefit Account as a negative energy value, and energy deliveries from BCH to BPA shall be recorded in the Transaction Benefit Account as a positive energy value.

(d) **Settling the Transaction Benefit Account Balance, Billing and Payment**

As soon as practicable after each August 31, the Parties shall verify the Transaction Benefit Account balance for the year prior (September 1 through August 31).

Unless otherwise agreed, a bill shall be issued on or about September 25 each year in the amount of the Transaction Account Balance, in U.S. dollars. If there is a negative account balance, BPA shall bill and BCH shall pay to BPA the amount of any negative Transaction Benefit Account balance, unless otherwise agreed by the Parties. If there is a positive account balance, BCH shall bill and BPA shall pay to BCH the amount of any positive Transaction Benefit Account balance, unless otherwise agreed by the Parties.

All bills shall be issued by electronic submittal unless electronic submittal is not practical, in which case each Party shall transmit a summary to the other Party electronically and send the entire bill by mail.

Payment of all bills shall be made by electronic funds transfer in accordance with instructions on the bill. Payment of all bills shall be made in full on or before the 20th day after the bill is issued. If the 20th day is a Saturday, Sunday, or holiday for the U.S. Federal Government or British Columbia, as applicable, the due date shall be the next business day.

After the due date, either Party may assess a late payment charge equal to the higher of:

(1) the U.S. Prime Rate as listed in the Wall Street Journal, or equivalent successor or replacement publication, in the first issue published during the month in which payment was due plus four percent, divided by 365; or

(2) the U.S. Prime Rate times 1.5, divided by 365;

applied each day to any unpaid balance. Each Party shall adjust the Transaction Benefit Account accordingly upon receipt of payment from the other Party.

7. BPA HEAD LOSS PAYMENTS

Subject to Section 13, Forced Evacuation of Non-Treaty Accounts, if, at any time, the sum of BPA's Active and Recallable Account balances are less than 2.77 km^3 (2.25 MAF), then BPA shall compensate BCH for Head Loss Energy, calculated on a daily basis.

The energy values associated with head losses shall be calculated as follows: first, the Head Loss Energy shall be calculated as the daily average energy of the head losses in accordance with Exhibit C, Mica Head Loss Calculation; then, the daily average value of that Head Loss Energy shall be calculated as the product of the Head Loss Energy in MWh times the daily flat prices on the same day, based on the price index in accordance with Exhibit B, Energy Pricing.

The energy value attributed to Head Loss Energy is a value allocated to BCH and shall be credited to the Transaction Benefit Account under Section 6(b)(2) unless Section 8, BCH Dry Period Provisions apply, in which case Head Loss Energy shall be delivered to BCH under Sections 8(e) and 8(f) and the value shall not be credited to the Transaction Benefit Account.

8. BCH DRY PERIOD PROVISIONS

(a) BCH Dry Period Operation Request

If BCH Dry Period Conditions occur, then BCH may request a BCH Dry Period Operation by written notice to BPA and shall supply BPA with data to support the determination of BCH Dry Period Conditions.

(b) BCH Dry Period Operation Release Rights

If BCH has requested a BCH Dry Period Operation, then BCH may request Water Transactions in the period of October through April to increase Arrow outflows, first from its Active Account up to the volume of water remaining in such account and then from its Recallable Account up to the volume of water remaining in such account. The amount of any such request shall not exceed the volume of water required to achieve a uniform flow rate of 56.6 m^3/s (2 kcfs) over the applicable Treaty Week.

If at the beginning of October and end of April a Treaty Week straddles two calendar months, then the Treaty Week shall be deemed to belong to the calendar month in which most of the days of the Treaty Week occur.

BCH Dry Period Operation Water Transaction requests shall be made in accordance with Section 4(a). BPA shall make all reasonable efforts to accommodate such requests, which shall be implemented in accordance with Section 4(d).

(c) **BPA Option during a BCH Dry Period Operation**
When BCH requests a Water Transaction under Section 8(b) above, BPA may request a concurrent Water Transaction to increase Arrow outflows, first from its Active Account up to the volume of water remaining in such account and then from its Recallable Account up to the volume of water remaining in such account. The amount of any such request shall not exceed the amount of BCH's Dry Period Operation Water Transaction request.

Any such BPA Water Transaction request shall be made in accordance with Section 4(a). BCH shall make all reasonable efforts to accommodate such requests, which shall be implemented in accordance with Section 4(d).

(d) **Scheduling of Equivalent Water Return**
If BCH Dry Period Operation Water Transactions under Section 8(b) occur, then as soon as conditions reasonably permit, BCH shall request Water Transactions to return an equivalent amount of water, first to its Recallable Account, if applicable, and then to its Active Account.

If BPA Water Transactions under Section 8(c) occur from BPA's Recallable Account, then as soon as conditions reasonably permit, BPA shall request Water Transactions to return an equivalent amount of water to its Recallable Account.

All Water Transaction requests under this Section 8(d) shall be made in accordance with Section 4(a). The Parties shall make reasonable efforts to accommodate such requests, which shall be implemented in accordance with Section 4(d). The Parties may agree to Water Transactions under Section 4 in addition to those under this Section 8(d).

(e) **Accounting and Energy Considerations**
BCH Water Transactions made under Sections 8(b) and 8(d) and the associated energy and energy values shall be tracked and accounted for under this Section 8 and not in the Transaction Benefit Account.

At any time when BCH Dry Period Operation Water Transactions under Section 8(b) occur, regardless of whether any BPA Water Transactions under Section 8(c) occur, BPA shall deliver all Head Loss Energy to BCH under Section 8(f), and the energy value attributed to such Head Loss Energy shall not be credited to the Transaction Benefit Account.

(f) **Energy Deliveries to BCH under a BCH Dry Period Operation**
When a BCH Dry Period Operation Water Transaction under Section 8(b) occurs, BPA shall deliver to BCH an amount of energy equivalent to the sum of the energy that will result from such BCH Dry Period Operation Water Transaction and any Head Loss Energy. Energy amounts associated with BCH Dry Period Operation Water Transactions under Section 8(b) shall be calculated by multiplying the estimated U.S. h/k by the Water Transaction volume on a daily basis and shall be adjusted for after-the-fact U.S. h/k in

accordance with Section 8(h). Head Loss Energy shall be calculated in accordance with Section 7.

In accordance with Section 11, Scheduling and Delivery of Energy and Exhibit G, Transaction Request Protocol and Energy Scheduling Guidelines, the energy to be delivered shall be estimated and prescheduled on a uniform hourly schedule for the upcoming week to the Delivery Point. The weekly period to be used for such energy deliveries shall be lagged one day from the Treaty Week in which the applicable BCH Dry Period Operation Water Transaction occurs. The Parties may mutually agree to alternate delivery schedules.

(g) **Energy Deliveries to BPA in Return**

When a BCH Water Transaction under Section 8(d) occurs, BCH shall deliver to BPA the amount of energy related to the water return and such energy shall be calculated by multiplying the estimated U.S. h/k by the Water Transaction volume on a daily basis, as adjusted for after-the-fact U.S. h/k in accordance with Section 8(h).

In accordance with Section 11, Scheduling and Delivery of Energy and Exhibit G, Transaction Request Protocol and Energy Scheduling Guidelines, the energy to be delivered shall be estimated and prescheduled on a uniform hourly schedule for the upcoming week to the Delivery Point. The weekly period to be used for such energy deliveries shall be lagged one day from the Treaty Week in which the applicable BCH Water Transaction occurs. The Parties may mutually agree to alternate delivery schedules.

(h) **After-the-Fact Energy Adjustments**

The Parties shall establish and maintain an energy adjustment account to record differences in estimated versus actual U.S. h/k and resulting energy amounts under Sections 8(f) and 8(g), as well as any adjustments in the Head Loss Energy calculation under Section 8(f). Energy amounts as a result of such adjustments shall be delivered in a timely manner by BCH or BPA, as the case may be, in accordance with Section 11, Scheduling and Delivery of Energy and Exhibit G, Transaction Request Protocol and Energy Scheduling Guidelines.

(i) **Capacity Limitations**

The Party obligated to deliver energy under Sections 8(f) or 8(g) may suspend delivery if, on the preschedule day, the Party delivering the energy determines that capacity limitations may compromise its ability to serve its load obligations. The Party suspending delivery shall provide the other Party with as much advance notice as is reasonably practicable. If an energy delivery is suspended, then unless the Parties otherwise agree, the energy not delivered shall be rescheduled to either Light Load Hours in the same day or to 168 hours forward from the original hour of delivery, at the receiving Party's option.

(j) **Differences in Value of Energy Delivered to BCH**

(1) Subject to 8(j)(2) below, the value of the energy delivered by one Party to the other under Section 8(f) and 8(g), as adjusted under Section 8(h), shall be calculated as the product of the energy delivered in MWh times the daily flat Energy Price on the day of delivery.

(2) If energy deliveries under Section 8(f) and 8(g), as adjusted under Section 8(h), are not flat in a day, then energy values will be calculated based on the Energy Price for the applicable HLH or LLH time blocks and delivered energy amounts.

(3) Upon completion the BCH Water Transactions made under Sections 8(b) and 8(d): if the value of energy delivered by BPA to BCH related to BCH Dry Period Operation Water Transactions (not including Head Loss Energy) exceeds the value of energy delivered by BCH to BPA, then such difference shall be subtracted from the Transaction Benefit Account balance; and if the value of energy delivered by BPA to BCH is less than the value of energy delivered by BCH to BPA, then no adjustment to the Transaction Benefit Account shall be made.

(k) **Transmission Costs**

Each Party shall be responsible for transmission on its system to and from the Delivery Point for energy deliveries under Sections 8(f) and 8(g). In consideration of such, BCH shall compensate BPA for all energy deliveries under 8(f) and 8(g) at the posted BPA hourly non-firm point-to-point transmission and ancillary services rates, or their successor rates. Losses shall be paid at the posted BPA Power Services transmission losses product rate, or its successor rate. If transmission is not available or transmission schedules are curtailed, then the energy deliveries shall be rescheduled as agreed by the Parties.

9. BPA DRY PERIOD PROVISIONS

(a) **Determination of BPA Dry Period Conditions**

The determination of BPA Dry Period Conditions shall be made using the NWRFC's early May water supply forecast for the April through August period as measured at The Dalles Dam. If the forecasting period changes from the current April through August period in a successor or replacement FCRPS Biological Opinion, then the period used for the NWRFC water supply forecast shall be adjusted to match. If requested by BPA prior to January 15, the NWRFC's water supply forecast for early April may be used for the year, rather than the early May forecast. All water supply forecasts used to determine BPA Dry Period Conditions water conditions will be consistent with those used in the Treaty Storage Regulation Study.

(b) **BPA Dry Period Operation Request**
Within seven days of the issuance of the NWRFC's water supply forecast in Section 9(a), if BPA Dry Period Conditions occur and if BPA did not request a BPA Dry Period Operation in the previous calendar year, then BPA may request a BPA Dry Period Operation by written notice to BCH and shall supply BCH with data to support the determination of BPA Dry Period Conditions.

If BPA Dry Period Conditions occur and BPA requested a BPA Dry Period Operation in the previous calendar year, then BPA may request Water Transactions to increase Arrow outflows under Section 9(c), and BCH, in its sole discretion, shall determine whether it can accommodate such request. If BCH elects to accommodate such request, then a BPA Dry Period Operation will be deemed to have been requested by BPA for that calendar year.

(c) **BPA Dry Period Operation Release Rights**
If BPA has requested a BPA Dry Period Operation, then BPA may request Water Transactions in the period from the BPA Dry Period Operation request through to the end of June of that calendar year, or such other period agreed to by the Parties, to increase Arrow outflows. The amount of such requests shall not exceed the lesser of: (1) 0.62 km^3 (0.5 MAF) and (2) the volume of water remaining in BPA's Active Account.

By agreement of the Parties, the rate of release shall be determined and adjusted, as necessary, to provide a smooth delivery of the volume of water requested by BPA. If at the end of June a Treaty Week straddles June and July, then the Treaty Week shall be deemed to belong in June if most of the days of the Treaty Week occur in June.

BPA Dry Period Operation Water Transaction requests shall be made in accordance with Section 4(a). BCH shall make all reasonable efforts to accommodate such requests, which shall be implemented in accordance with Section 4(d).

(d) **BCH Option during a BPA Dry Period Operation**
When BPA requests a Water Transaction under Section 9(c) above, BCH may release a portion of the requested volume of water from BCH's Active Account up to the lesser of: (1) 50% of the water requested by BPA and (2) the volume of water remaining in BCH's Active Account. The remaining balance of water requested by BPA shall be released from BPA's Active Account.

(e) **Accounting and Energy Considerations**
Energy accounting for Dry Period Operation Water Transactions under this Section 9 shall be in accordance with Section 6(b).

10. ENERGY PRICING

Energy Prices shall be determined consistent with Exhibit B. For purposes of determining energy values, Energy Prices will be limited to a minimum of $0.00 for both Heavy Load Hour blocks and Light Load Hour blocks, unless otherwise agreed.

Such limitation shall be in effect so long as BPA does not purchase or sell negative priced energy, except as may inadvertently occur when BPA makes price taker bids to purchase energy out of the California ISO (or other jurisdictions that may offer price taker bids) and the Locational Marginal Price (LMP) is negative at the point of purchase.

In the event that BPA's negative pricing policy and/or practices are amended or replaced, BPA shall promptly notify BCH in writing, and the Parties shall amend this limitation accordingly. Such amendment will be based on the principle that the price should reflect the benefit BPA, in accordance with its policy, would receive for additional/decremental energy produced at the Downstream Federal Hydro Projects on a preschedule basis as a result of Water Transactions under this Agreement. In the event the Parties are unable to agree on amendments to this Agreement, the matter shall be resolved pursuant to Section 18, Dispute Resolution.

11. SCHEDULING AND DELIVERY OF ENERGY

In accordance with Exhibit G, all energy deliveries under this Agreement shall be submitted on a preschedule basis, may be scheduled on non-firm transmission, and are subject to transmission availability. Schedules for delivery of energy under this Agreement shall be made at the Delivery Point.

If transmission is not available or transmission schedules are curtailed, then the energy deliveries shall be rescheduled as agreed between the Parties. Where BPA is the Delivering Party under Section 6(c), BPA may limit the agreed-upon south to north energy delivery within any Light Load Hour to the difference between the prescheduled Canadian Entitlement delivery and the maximum Canadian Entitlement that can be scheduled on any hour. The Parties may mutually agree to alternate delivery schedules.

Subject to Section 8(k), unless otherwise agreed each Party shall be responsible for acquiring and scheduling transmission and all transmission costs, including losses, on its system to or from the Delivery Point for energy deliveries under this Agreement.

12. PRIORITY USE OF FACILITIES

(a) **Priority of the Columbia River Treaty**

The use of Treaty storage space and the use of all other facilities at Mica Arrow, Duncan and Downstream U.S. Hydro Projects to fulfill the requirements of the Treaty shall receive priority over all uses provided for in this Agreement.

(b) **Priority of Requests under this Agreement**

When concurrent Water Transaction requests by BPA and BCH under this Agreement cannot be accommodated, BCH and BPA Dry Period Operation release rights under Sections 8 and 9 shall receive priority, after which the priority shall be as follows: if BPA and BCH Water Transaction requests are either both positive or both negative, and the combined request exceeds the available limited flexibility as specified by the Parties, then the total amount

of the Water Transaction requests shall be reduced as necessary to conform to such limits, first by reducing the larger request by up to the amount it exceeds the smaller request and then by reducing each request by equal amounts.

13. FORCED EVACUATION OF NON-TREATY ACCOUNTS

If water recorded in any non-Treaty account must be evacuated because:

(a) the storage space is no longer available;

(b) BCH has determined that a release is necessary for flood control, safety, protection of structures, or any other cause that BCH reasonably determines constitutes an emergency in British Columbia; or

(c) the U.S. Entity under the Treaty makes an on-call flood control operation request pursuant to the Treaty;

then BCH shall give notice to BPA by any means practicable and confirm such notice in writing as soon as reasonably practicable, and shall have the right to initiate the release of water without the consent of BPA. In such event, each Recallable Account shall be reduced first to its Initial Water Balance, followed by reducing the Active Account balances, and finally reducing the remaining balance in the Recallable Accounts. For each category of account, as per the reduction priority above, the release will be first from the Party's account with the largest balance until the Parties' respective account balances are equal, and then such accounts shall be released concurrently on an equal basis.

Releases of water and return of water under this Section 13 shall be considered BCH or BPA Water Transactions, as the case may be, under Section 6 for purposes of energy and energy value accounting, including the associated crediting and debiting of the Transaction Benefit Account.

The obligation to return any of the water evacuated under this Section 13 shall be pursuant to procedures to be agreed upon by the Parties at such time. If the Parties cannot agree, then the matter shall be resolved pursuant to Section 18, Dispute Resolution.

In the event of a forced evacuation under paragraphs (a) or (b) above, the calculation of BPA compensation for head losses on the BCH system under Section 7 shall be adjusted to use the maximum balance allowable for Active and Recallable Accounts in place of Initial Water Balances, until such time as the forced evacuation has been lifted and BPA has had reasonable opportunity to return the equivalent amount of water evacuated from its accounts.

In the event of a forced evacuation under paragraph (c) above, the calculation of BPA compensation for head losses on the BCH system under Section 7 shall not be adjusted, unless BCH has been otherwise compensated under the Treaty or other agreements for the resulting head losses, in which case the calculation of BPA

compensation for head losses on the BCH system under Section 7 shall be adjusted as described in the preceding paragraph.

14. FORCE MAJEURE

(a) A Party shall not be in breach of an obligation under this Agreement to the extent its failure to fulfill the obligation is due to a Force Majeure. "Force Majeure" means an event beyond the reasonable control, and without the fault or negligence, of the Party claiming the Force Majeure, that prevents that Party from performing its obligations under this Agreement and which that Party could not have avoided by the exercise of reasonable care, diligence and foresight. A Force Majeure may include, but is not limited to the following events:

(1) strikes, work stoppage, riot, civil or labor disturbance; and

(2) floods, earthquakes, other natural disasters, or terrorist acts; and

(3) final orders or injunctions issued by a court or regulatory body having subject matter jurisdiction which the Party claiming the Force Majeure, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court having subject matter jurisdiction.

(b) Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered a Force Majeure. The economic hardship of either Party shall not constitute a Force Majeure. Nothing contained in this provision shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

(c) If a Force Majeure prevents a Party from performing any of its obligations under this Agreement, such Party shall:

(1) immediately notify the other Party of such Force Majeure by any means practicable and confirm such notice in writing as soon as reasonably practicable;

(2) use commercially reasonable efforts to mitigate the effects of such Force Majeure, remedy its inability to perform, and resume full performance of its obligation hereunder as soon as reasonably practicable;

(3) keep the other Party apprised of such efforts on an ongoing basis; and

(4) provide written notice of the resumption of performance.

(d) A Force Majeure shall not relieve a Party from its obligations to restore its Active Account and Recallable Account to the Initial Water Balance for each account upon expiry or early termination of the Agreement and a Party shall

be in breach of this Agreement if it fails to do so, notwithstanding a Force Majeure event.

15. COORDINATION RESPONSIBILITIES

As necessary, BPA shall be responsible for coordinating any flow changes resulting from this Agreement with the U.S. Army Corps of Engineers, the Bureau of Reclamation, and affected Mid-C Participants.

16. NON-TREATY OPERATING COMMITTEE

(a) **Members and Meetings**

Within 30 days of the Effective Date, the Parties shall establish a Non-Treaty Operating Committee (the "NTOC") that shall include two members from each Party whom shall confer regularly and meet at least once a year to review and document various operating issues.

(b) **Purpose and Authority**

The NTOC shall provide a forum for discussing issues and problems that may arise during the implementation of this Agreement. The NTOC shall review and document various operating issues including, but not limited to: power scheduling procedures; methods of calculating the amounts or value of energy otherwise stored or released; operating plans; and planned maintenance of transmission and generating facilities used to implement this Agreement.

The NTOC shall have the authority to amend any Exhibit to this Agreement by unanimous agreement, but shall have no authority, expressly or by course of conduct, to otherwise agree to amend the body of this Agreement. Decisions of the NTOC shall be by unanimous agreement.

17. MANAGEMENT OF CREDIT RISK

(a) For the purpose of managing credit risk, as of the Effective Date each Party shall have established a Transaction Benefit Account balance monitoring limit of $40 million (positive or negative). If at any time the Transaction Benefit Account balance owed to a Party (First Party) exceeds the monitoring limit established by that Party, then the First Party may, by written notice to the other Party (Second Party), require the Second Party to make an early payment to bring the Transaction Benefit Account balance to at least 20% below the monitoring limit, or to such other balance as may be agreed to by the Parties. The Second Party shall pay the amount of such early payment to the First Party. Issuance and payment of bills for early payment shall be made in accordance with Section 6(d).

(b) The Parties may agree to energy deliveries in lieu of early payment required by this Section 17. Any such energy deliveries shall be made in accordance with Section 6(c).

(c) At any time during the term of the Agreement, a Party may change its monitoring limit by written notice to the other Party, if:

(1) BPA is no longer a federal agency or instrumentality of the United States, if the other Party is BPA; or

(2) BCH is no longer a Crown Corporation of the Province of British Columbia, if the other Party is BCH.

(d) At any time during the term of the Agreement, either Party may change its monitoring limit with the consent of the other Party, such consent not to be unreasonably withheld.

18. DISPUTE RESOLUTION

If a dispute arises out of or relates to this Agreement, or a breach thereof, and if the dispute cannot be settled by the NTOC or through other negotiation, then the Parties agree to first try in good faith to settle the dispute by mediation in accordance with the International Mediation Rules of the International Centre for Dispute Resolution (a division of the American Arbitration Association) before resorting to litigation or some other dispute resolution procedure.

19. INDEMNIFICATION

Subject to Section 20, and with the exception of Sections 13(a) and 13(b), BPA agrees to indemnify BCH for payments of judgments or settlements made by BCH to any Mid-C Participant for actions BCH has taken pursuant to and consistent with the terms of this Agreement. Any such BCH settlements shall be subject to the prior approval of BPA.

20. MID-C PARTICIPANTS

If BPA enters into a companion agreement with one or more Mid-C Participants, which do not stem from the Pacific Northwest Coordination Agreement, that would result in participation with respect to BCH Water Transactions as contemplated under this Agreement, then BPA shall notify BCH in writing as soon as practicable and the Parties shall amend this Agreement to account for: (1) the sharing of benefits among BPA and the applicable Mid-C Participants and (2) any other relevant provisions as determined by the Parties. If any such companion agreement is executed and if the Mid-C Participant has entered into an indemnification agreement with BCH in a form satisfactory to BCH, then the Parties shall deem that Section 19, Indemnification, does not apply with respect to that Mid-C Participant for so long as such indemnification agreement is in force and effect.

21. INFORMATION EXCHANGE AND CONFIDENTIALITY

Upon request, each Party shall provide the other Party with any information that is necessary to administer this Agreement.

Before one Party provides information to the other Party that is confidential, or is otherwise subject to a privilege or nondisclosure, each shall clearly designate such information as confidential. Each Party shall notify the other in writing as soon as practicable of any request received under applicable domestic law (e.g., the U.S. Freedom of Information Act (FOIA), British Columbia's Freedom of Information and Protection of Privacy Act (FOIPPA), or under any other federal, state, or provincial

law or court or administrative order) for any confidential information. The Parties shall only release such confidential information to comply with applicable law or if required by any other federal law or court or administrative order. Each Party shall limit the use and dissemination of confidential information within their respective organizations to employees who need it for purposes of administering this Agreement.

22. GENERAL PROVISIONS

(a) **Entire Agreement and Order of Precedence**
This Agreement, including documents expressly incorporated by reference, constitutes the entire agreement between the Parties with respect to the subject matter of this Agreement. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement. The body of this Agreement shall prevail over the exhibits to this Agreement in the event of a conflict.

(b) **Assignment**
Except as provided for in this Section or with the consent of the other Party, neither Party may assign its rights or obligations under the Agreement to a third party. Such consent shall not be unreasonably withheld. BCH may assign its obligations to receive and deliver any energy required to be delivered by BCH to BPA, or by BPA to BCH, under this Agreement to BCH's subsidiary, Powerex Corp., on written notice to BPA.

(c) **No Third-Party Beneficiaries**
This Agreement is made and entered into for the sole benefit of the Parties. The Parties intend that no other person or entity shall be a direct or indirect beneficiary of this Agreement, and nothing in this Agreement is intended to provide a basis for any action, either legal or equitable, by any person or class of persons against the United States, the Province of British Columbia, or their respective departments, agencies, crown corporations, instrumentalities, entities, officers, or employees.

(d) **Waivers**
No waiver of any provision or breach of this Agreement shall be effective unless such waiver is in writing and signed by the waiving Party, and any such waiver shall not be deemed a waiver of any other provision of this Agreement or of any other breach of this Agreement.

(e) **Applicable Law**
This Agreement shall not be construed to amend or modify the Treaty or the obligations of Canada or the United States under such. The Parties intend that this Agreement shall be an operational agreement governed by applicable domestic law and not international law.

(f) **Agency Policies**
Any reference in this Agreement to a BPA or BCH policy, including any revisions, does not constitute agreement of the other Party to such policy by execution of this Agreement, nor shall it be construed to be a waiver of the right of the other Party to seek judicial review of any such policy.

(g) **Amendments**
Except as expressly stated otherwise in this Agreement, no amendment of this Agreement shall be of any force or effect unless set forth in writing and signed by authorized representatives of each Party.

(h) **Survival**
All rights, obligations, liabilities and remedies of the Parties which accrued prior to the expiration or early termination of this Agreement, or which are by their nature continuing, including Sections 6(d), 19 and 24, and all other provisions necessary for the interpretation or enforcement of such provisions shall survive expiration or early termination of this Agreement.

(i) **Notices**
Any written notice required under this Agreement shall be provided to the other Party in one of the following ways:

(1) delivered in person;

(2) by a nationally recognized delivery service with proof of receipt;

(3) by United States or Canadian certified mail with return receipt requested;

(4) electronically by facsimile or e-mail; or

(5) by another method agreed to by the Parties.

Notices are effective when received.

23. MAINTENANCE OF REQUIRED APPROVALS

This Agreement is subject to BCH and BPA maintaining throughout the term of this Agreement specified in Section 1, all necessary and applicable regulatory and governmental licenses, permits or other approvals necessary to satisfy each Party's respective obligations under this Agreement. If any such license, permit or other approval expires or ceases to be effective for any reason, then this Agreement shall expire as of the same date and time as the expiration of that license, permit or other approval. The Party with the expiring license, permit or other approval shall act in good faith to notify in writing the other Party of the pending expiration as soon as possible. Upon such notice, or upon a mutually agreed later date, the provisions in Sections 24(b) and 24(c) concerning Water Transactions and final Transaction Benefit Account balance and payment shall apply.

24. EXPIRATION AND EARLY TERMINATION

At least 24 months prior to the Expiration Date, or as otherwise mutually agreed by the Parties, the NTOC shall complete a plan to manage the balancing of accounts to achieve Initial Water Balances in a timely manner as required in Sections 24(a) and 24(b) below.

(a) **Expiration**

If this Agreement is not terminated early under Section 24(b), then each Party shall restore its Active Account and Recallable Account to the Initial Water Balances by 2400 hours on the Expiration Date.

(b) **Early Termination**

During the term of this Agreement, either Party may request early termination of the Agreement if:

(1) operating requirements or other restrictions imposed after the Effective Date materially diminishes the benefits received by a Party under the Agreement; or

(2) non-power requirements or objectives on a Party's system, such as water use planning and biological opinion requirements or objectives, that are materially negatively impacted by Water Transactions made under this Agreement.

Any early termination request shall be given by written notice, not later than September 1 of any year with the intent to terminate at 2400 hours on December 31 two calendar years, or at least 28 months, after such notice was given.

As soon as practicable after an early termination request is given, the Parties shall make a good faith attempt to agree upon a mutually acceptable alternative to termination. If, by January 15 of the following calendar year after a termination request has been given, termination has been deemed unavoidable by Parties, the Party that gave notice of intent to terminate shall provide the other Party with a final written notice of termination, and the Expiration Date for this Agreement shall then be 2400 hours on the December 31 that is two calendar years after the calendar year in which the early termination request was given (i.e., the intended termination date identified in the early termination request).

Unless otherwise agreed by the Parties, once the Party requesting termination has provided the other Party a final written notice of termination, all Water Transactions made under this Agreement shall be for the purpose of restoring the Active Accounts and Recallable Accounts to their Initial Water Balances, and each Party shall restore its Active Account and Recallable Account to the Initial Water Balances by the Expiration Date as described in this Section 24(b).

(c) **Issuance and Payment of Final Bill**
Within thirty (30) calendar days following the Expiration Date in Sections 24(a) or 24(b) above, the Parties shall verify the final Transaction Benefit Account balance. Within sixty (60) calendar days following such Expiration Date, a bill will be issued in the amount of the final Transaction Benefit Account balance and payment shall be made in accordance with Section 6(d).

25. SIGNATURES

The Parties have caused this Agreement to be executed as of the date both Parties have signed this Agreement.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY	BONNEVILLE POWER ADMINISTRATION
By	By
Name CHARLES REID *(Print/Type)*	Name Stephen J. Wright *(Print/Type)*
Title PRESIDENT + CEO	Title Administrator/CEO
Date APRIL 10 2012	Date March 23, 2012

Exhibit A
DAILY CONVERSION FACTORS (H/K) CALCULATION

This exhibit describes the intent and basic procedures used to determine federal and U.S. daily conversion factors (Federal h/k and U.S. h/k) used in calculating the deemed change in generation on the Downstream Federal Hydro Projects or Downstream U.S. Hydro Projects resulting from Water Transactions under this Agreement. The calculated h/k's assume the water flows through each Downstream U.S. Hydro Project the day after each Water Transaction and include adjustments for limitations on project generating capability such as required spill, reserve requirements, and turbine generation limits.

1. CALCULATION

(a) General

(1) The Federal h/k is the sum of the individual Downstream Federal Hydro Project h/k values.

(2) The U.S. h/k is the sum of individual Downstream U.S. Project h/k values.

(3) The daily h/k for each project is the daily average project generation divided by the daily average turbine flow, adjusted for operating limits including such factors as required spill, reserve requirements, and turbine generation limits.

(4) With the exception of Water Transactions under Section 5 of this Agreement, if both positive and negative Water Transactions occur concurrently, then the negative Water Transaction will be examined first based on the actual flow value, and the positive Water Transaction will be examined second based on the actual flow increased by the negative Water Transaction.

(5) If the federal system is spilling due to lack of load, then the Federal h/k is 0. In such instance, a change in flow from a Water Transaction would not result in a change in generation at the Downstream Federal Hydro Projects.

(b) Determining Project h/k Values

The ability of a project to increase or decrease generation as a result of Water Transactions includes consideration of project operating limits. If a project is operating near its turbine or generating limits, or there is project spill, then the calculated h/k will include the effects of those limitations.

(1) It is assumed all Water Transactions pass through Downstream U.S. Hydro Projects the day following the Water Transaction.

(2) Positive Water Transactions (outside fish passage season):

(i) If there is no spill, then all of the additional flow is assumed converted to generation and the project h/k is the daily average generation divided by the daily average turbine flow.

(ii) If a project spills due to lack of turbine capability, then all or a portion of the Water Transaction is spilled. The h/k is calculated as the average generation divided by the turbine flow multiplied by the percentage of the Water Transaction that could be generated.

(3) Negative Water Transactions (outside fish passage season):

(i) If there is any spill at a project due to lack of turbine capability, then the h/k for that project is 0 MW/kcfs. A negative Water Transaction reduces downstream flow. If flows had been higher the project would have spilled, thus there is no change in generation resulting from the Water Transaction.

(ii) If a project is operating at maximum turbine capability, then the h/k for that project is 0 MW/kcfs because there is no change in generation resulting from the Water Transaction.

(iii) If a project is operating near turbine capability then all or a portion of the Water Transaction may result in a generation change. The portion that affects generation is limited to the difference between the maximum turbine flow and the actual turbine flow. In this case, the project h/k is calculated as the average generation divided by the average turbine flow multiplied by the percentage of the Water Transaction that could have been generated.

(4) Fish Passage Season brings in additional project constraints including turbine generating limits and spill requirements that vary daily and hourly within the day. Determination of project h/k's during fish passage season will be based upon the proportion of any Water Transaction that was or could have been generated within the constraints.

(c) **Calculated Generation Change**
The generation change resulting from a Water Transaction is calculated as the Water Transaction multiplied by the sum of the project h/k's, including project operating limits.

2. PRIORITY

To calculate h/k's when there are multiple Water Transactions under this and other agreements, the following priority of calculations will apply:

(1) Transactions under the Columbia River Treaty;

(2) Water Transaction releases under Sections 8 and 9 of the Agreement;

(3) Other Water Transactions under this Agreement.

3. **EXAMPLES**

The following examples are provided for illustration purposes. The calculations shown are for the Federal h/k, however the same principles would apply to the U.S. h/k.

(a) **Example 1. Spill Due to Lack of Load (See 1(a)5 in this Exhibit)**
During a winter rain event, BPA and BCH each requested a -10 kcfs Water Transaction. Although federal projects had generating capacity, there was insufficient load and Grand Coulee spilled 30 kcfs all hours of one day. The federal h/k on that day was 0 MW/kcfs.

(b) **Example 2. Positive Water Transaction That is Partially Spilled (See 1(b)(2)(ii) in this Exhibit)**
BPA requested a 5 kcfs Water Transaction and BCH requested a 10 kcfs Water Transaction. McNary was operating at maximum turbine capability and spilling 12 kcfs on a day-average basis. In this case a portion of the Water Transaction was spilled: 12 kcfs was spilled and 3 kcfs was generated. The h/k calculation is as follows:

Daily average generation/daily average turbine flow = 5.4 MW/kcfs (typical value)

Water Transaction generated: 3 kcfs

Total Water Transaction: 15 kcfs

h/k = 5.4 MW/kcfs * 3/15 = 1.08 MW/kcfs

(c) **Example 3. Negative Water Transaction Limited by Turbine Capability (See 1(b)(3)(iii) in this Exhibit)**
BPA and BCH each requested a -5 kcfs Water Transaction. McNary's daily average turbine flow was 7 kcfs less than its maximum turbine capability. In this case the maximum amount of additional water that could have been generated is 7 kcfs.

Daily average generation/daily average turbine flow = 5.4 MW/kcfs (typical value)

Water Transaction that could have been generated: 7 kcfs

Total Water Transaction: 10 kcfs

h/k = 5.4 MW/kcfs * 7/10 = 3.78 MW/kcfs

(d) **Example 4. Water Transactions with Percentage of Flow Spilled for Fish**

During fish passage season BPA and BCH each request a -7.5 kcfs Water Transaction. Due to fisheries requirements, McNary is required to spill 40% of its outflow and no other restrictions are limiting operations. Of the -15 kcfs of Water Transactions, 40% or 6 kcfs would have been spilled and 9 kcfs would have been generated.

Daily average generation/daily average turbine flow = 5.4 MW/kcfs (typical value)

Water Transaction that could have been generated: 9 kcfs

Total Water Transaction: 15 kcfs

h/k = 5.4 MW/kcfs * 9/15 = 3.24 MW/kcfs

Exhibit B
ENERGY PRICING

1. DETERMINATION OF ENERGY PRICES

Subject to Section 10 of the Agreement and Sections 3 and 4 of this Exhibit B, prices for determining energy values under this Agreement shall be based on the daily pre-schedule index for valuing energy in the Mid-Columbia region as described in Section 2 below.

2. DAILY PRE-SCHEDULE INDEX

The Parties agree to use the Intercontinental Exchange (ICE) indices as described in this Section 2.

(a) **Definition of Hourly Blocks**

"Heavy Load Hours" or "HLH" means hours ending (HE) 0700 through HE 2200 (16 hours per day) Pacific prevailing time, Monday through Saturday (6 days per week), excluding North American Electric Reliability Corporation (NERC) holidays.

"Light Load Hours" or "LLH" means HE 0100 through HE 0600 and HE 2300 through HE 2400 Pacific prevailing time and all hours on Sundays and NERC holidays.

(b) **Use of Index**

For any given day over the term of this Agreement, the following ICE indices shall apply:

(1) for Heavy Load Hours, the Mid-C On-Peak Index, being the volume-weighted "average" price for Mid-C day ahead transactions in Heavy Load Hours in that day (or days where the index covers more than one day), as published in the ICE Day Ahead Power Price Report; and

(2) for Light Load Hours, the Mid-C Off-Peak Index, being the volume-weighted "average" price for Mid-C day ahead transactions in Light Load Hours in that day (or days where the index covers more than one day), as published in the ICE Day Ahead Power Price Report.

(c) **Diurnal Energy Pricing**

Energy Prices under this Agreement shall be determined by:

(1) for Light Load Hour blocks in any day, the ICE Index for Light Load Hours in that day,

(2) for Heavy Load Hour blocks in any day, the ICE Index for Heavy Load Hours in that day, and

(3) for daily flat energy blocks in any day, the weighted average of the ICE Index for Light Load Hours and for Heavy Load Hours in that day, based on the number of Light Load Hours and Heavy Load Hours in the day; provided that if any Heavy Load Hour or Light Load Hour block prices that make up the flat index are negative, such prices shall be adjusted in accordance with and subject to Section 10 of the Agreement.

3. UPDATE/REPLACEMENT INDEX

By August 31 of any year, either Party may propose use of a different price index by providing notice in writing to the other Party of its view that the proposed index is the most generally accepted and used by market participants for daily pre-scheduled transactions in the Mid-Columbia region of the United States of America and that it is appropriate for the kind of product represented by deemed energy or delivered energy under this Agreement. In such case, the applicable index shall be an index that most closely applies to energy and energy deliveries under this Agreement (considering applicable factors and the intent of the Parties, including such factors as delivery point, firmness of electricity, time of day and general acceptance and use of such index by market participants), or such other index as the Parties may agree.

If the Parties agree within 30 days after the foregoing notice is given, the index will be updated, including any changes to definitions of hourly energy blocks, and will be implemented beginning on October 1 of that year. If the Parties do not agree on a change to the index, then the prior agreed index shall remain in effect.

4. CHANGE IN HOURS USED FOR PRICING

If the hours used for energy pricing by the ICE Index or any replacement thereof change from the hours used in the definitions of "Light Load Hours" and "Heavy Load Hours", the Parties will revise, to the extent reasonable, the definitions in this Agreement to take into account the hours used by the ICE Index or replacement, and will amend, to the extent reasonable, any other provision of this Agreement that uses the amended definitions, in order to reflect the original intent of this Agreement. If the Parties are unable to so agree within 30 days after the change in the hours used for pricing of energy, either Party may refer the matter to dispute resolution pursuant to Section 18 of the Agreement.

Exhibit C
MICA HEAD LOSS CALCULATION

Two shadow contents, S_1 and S_2, shall be determined daily as follows:

Storage contents S_1 and S_2 are expressed in ksfd and are defined by the following formulas:

$$S_1 = M_{Base} + M_{TRT} + 2*ABi + 2*RBi$$
$$= 4060.511 + M_{TRT} + 2268.750$$

$$S_2 = M_{Base} + M_{TRT} + \min(RB_i + AB_i, RB_{BPA} + AB_{BPA}) + \min(RB_i + AB_i, RB_{BCH} + AB_{BCH})$$
$$= 4060.511 + M_{TRT} + \min(1134.375, RB_{BPA} + AB_{BPA}) + \min(1134.375, RB_{BCH} + AB_{BCH})$$

WHERE:

All balances are as of 2400 hours on the day for which the calculation is made and are in units of ksfd.

M_{Base} is the Mica dead storage space and other storage space not impacted by this Agreement set equal to 4060.511 ksfd.

RB_i is the Recallable Account Initial Water Balance set to 378.125 ksfd each for BPA and BCH;

RB_{BCH} and RB_{BPA} are equal to the balances in the BCH and BPA Recallable Accounts, respectively;

M_{TRT} is equal to the Mica Treaty content pursuant to the Detailed Operating Plans including any Supplemental Operating Agreements in effect;

AB_i is the Active Account Initial Water Balance set to 756.250 ksfd, each for BPA and BCH;

AB_{BPA} is the balance in the BPA Active Account, subject to the adjustment below; and

AB_{BCH} is the balance in the BCH Active Account, subject to the adjustment below.

If AB_{BCH} exceeds AB_i, for the purpose of head loss calculations, an adjustment shall be made by deducting the difference ($AB_{BCH} - AB_i$), and adding such difference to AB_{BPA}. The purpose of this adjustment is to give BPA credit in the head loss calculation for the water, if any, which BCH has in their Active Account balance in excess of 1.5 MAF.

Provided, however, that if either content S_1 or S_2 exceeds the maximum content at which Mica could be operated on such day, such content shall be set equal to the maximum content. Such maximum shall be the lowest of the following contents:

(i) Mica's normal full content, which is 10121.100 ksfd;

(ii) Mica's maximum content at 2400 hours on such day as prescribed in the Columbia River Treaty Flood Control Operating Plan; or

(iii) Any other limits on maximum contents at Mica as determined by BCH.

The amount of total head loss energy shall be determined daily according to the following formula:

$$HLE_T = (HK_1 - HK_2) \times Q_{DOP} \times 24 \text{ hours}$$

WHERE:

HLE_T is the total head loss in MWh;

HK_1 is the water to energy conversion factor for Mica in MW/kcfs at content S_1 in ksfd as determined by linear interpolation from Column (3) of Exhibit D;

HK_2 is the water to energy conversion factor for Mica in MW/kcfs at content S_2 as determined by linear interpolation from Column (3) of Exhibit D; and

Q_{DOP} is the turbine discharge in kcfs at Mica on such day pursuant to the Detailed Operating Plan currently in effect including any supplemental Treaty operating agreements.

If the amount of total head loss is not zero, the portion of such total allocated to BPA on such day shall be determined according to the following formula:

$$HLE_{BPA} = \frac{HLE_T \times \max(AB_i + RB_i - AB_{BPA} - RB_{BPA}, 0)}{\max(AB_i + RB_i - AB_{BPA} - RB_{BPA}, 0) + \max(AB_i + RB_i - AB_{BCH} - RB_{BCH}, 0)}$$

WHERE:

HLE_{BPA} is the amount of head loss energy allocated to BPA on such day; and

all other terms are as defined above.

Provided, however, if the resultant HLE_{BPA} is negative, such amount shall be set to zero.

Exhibit D
MICA PLANT CHARACTERISTICS

(1)	(2)	(3)
Reservoir Elevation (feet)	Storage Content (kcfs-days)	Water-to-Energy Conversion Factor (kW/cfs)[1]
2475.0	10121.1	45.09
2470.0	9854.8	44.77
2465.0	9592.7	44.42
2460.0	9334.8	44.06
2455.0	9081.0	43.69
2450.0	8831.4	43.31
2445.0	8586.0	42.92
2440.0	8344.8	42.53
2435.0	8107.8	42.13
2430.0	7874.9	41.74
2425.0	7646.2	41.33
2420.0	7421.6	40.93
2415.0	7201.3	40.53
2410.0	6985.1	40.13
2405.0	6773.0	39.75
2400.0	6565.1	39.36
2395.0	6363.4	38.95
2390.0	6170.1	38.55
2385.0	5984.8	38.14
2380.0	5806.7	37.73
2375.0	5635.2	37.32
2370.0	5469.9	36.91
2365.0	5310.2	36.50
2360.0	5155.7	36.09
2355.0	5005.8	35.67
2350.0	4860.1	35.26
2345.0	4718.3	34.83
2340.0	4580.0	34.41
2335.0	4444.1	33.98
2330.0	4310.2	33.54
2325.0	4178.2	33.11
2320.0	4048.1	32.67

[1] Tailwater elevation assumed to be 1880.7 feet based on 30,000 cfs Mica discharge with Revelstoke in-service.

Exhibit E
POTENTIAL OPERATIONAL LIMITATIONS ON NTSA TRANSACTIONS

Month	Project	Issue	Limitations on Positive Water Transactions	Limitations on Negative Water Transactions
January	Arrow	Whitefish flows downstream of Arrow	Transactions possible if Treaty flows are low. Desire to maintain Arrow outflows for whitefish spawning such that eggs broadcast in January can be protected through March.	Transactions possible in many water conditions, provided the reduced flows do not adversely impact survival of spawned whitefish eggs.
	Priest Rapids	Vernita Bar flows	Unlikely to be limiting	Minimum flows needed to protect salmon redds at Vernita Bar (55-70 kcfs). Chum requirement typically more limiting.
	Bonneville	Chum salmon protection	Unlikely to be limiting	Minimum flows needed to protect salmon redds (110-135 kcfs)
February	Arrow	Whitefish flows downstream of Arrow	Unlikely to be limiting	Transactions possible if flows are high enough survival that spawned whitefish eggs are not adversely impacted
	Priest Rapids	Vernita Bar flows	Unlikely to be limiting	Minimum flows needed to protect salmon redds at Vernita Bar (55-70 kcfs). Chum requirement typically more limiting.
	Bonneville	Chum salmon protection	Unlikely to be limiting	Minimum flows needed to protect salmon redds (110-135 kcfs)
March	Arrow	Whitefish flows downstream of Arrow	Unlikely to be limiting	Transactions possible if flows are high enough survival that spawned whitefish eggs are not adversely impacted
	Grand Coulee	Meet minimum elevation for refill to flood control elevation mid Apr.	Unlikely to be limiting	Limited by flow needed to meet downstream minimum flow and elevation target.
	Priest Rapids	Vernita Bar flows	Unlikely to be limiting	Minimum flows needed to protect salmon redds at Vernita Bar. May become more limiting than chum requirement.

Month	Project	Issue	Limitations on Positive Water Transactions	Limitations on Negative Water Transactions
	Bonneville	Chum salmon protection	Unlikely to be limiting	Minimum flows needed to protect salmon redds (110-135 kcfs)
April	Arrow	Trout Spawning	Limited - low flow desired (15-35 kcfs) so that flows are steady or increasing through June.	Limited - low flow desired (15-35 kcfs) so that flows are steady or increasing through June.
	Grand Coulee	Meet mid-April flood control elevation	Unlikely to be limiting	Limited by flow needed to meet downstream minimum flow and reach flood control elevation mid-April.
	Priest Rapids	Steelhead flows	Unlikely to be limiting	Minimum flows needed for salmon (around 135 kcfs)
May	Arrow	Trout spawning	Limited - need to maintain flows through June	Limited - need to maintain flows through June
	McNary	Salmon flows	Desirable in dry years.	Limited – if flows exceed what is needed for salmon, may be able to shape water into future periods. More limiting than Priest Rapids requirement.
June	Arrow	Trout spawning	Possible, depending on flow levels	Limited - need to maintain flows through June
	Grand Coulee	Salmon flows and refill	Possible if flows downstream are low	Possible – need to maintain flow levels downstream and refill
	McNary	Salmon flows	Possible if flows downstream are low	Possible if flows are high
July	McNary	Salmon flows	Possible	Limited, but possible if flows are high
August	McNary	Salmon flows	Unlikely to be limiting	Very limited. Required release of any spring net storage.
September	Grand Coulee	Minimum elevation of 1283 ft.	Unlikely to be limiting	Limited unless there is good water
	Bonneville	Minimum flow for navigation	Unlikely to be limiting	May be limiting

Month	Project	Issue	Limitations on Positive Water Transactions	Limitations on Negative Water Transactions
October	Priest Rapids	Vernita Bar salmon	May be limited in high flow conditions. Daytime flows limited to (50-70 kcfs) mid-Oct – late Nov. for fall Chinook spawning	Largely unrestricted
	Bonneville	Minimum flow for navigation	Unlikely to be limiting	May be limiting
November	Priest Rapids	Vernita Bar salmon	May be limited in high flow conditions. Daytime flows limited to (50-70 kcfs) mid-Oct – late Nov. for fall Chinook spawning	Largely unrestricted
	Bonneville	Chum salmon protection	Limited in high flow conditions	Limiting Minimum flows needed to protect salmon redds (110-135 kcfs)
December	Priest Rapids	Vernita Bar salmon	May be limited in high flow conditions. Daytime flows limited to (50-70 kcfs) mid-Oct – late Nov. for fall Chinook spawning	Largely unrestricted
	Bonneville	Chum salmon protection	Limited in high flow conditions	Limiting Minimum flows needed to protect salmon redds (110-135 kcfs)

Exhibit F
DETERMINATION OF AVAILABLE ENERGY BALANCE

1. The right of a Party to request energy deliveries pursuant to Section 6(c) of the Agreement is based on the Party having an Available Energy Balance in its favor, as calculated in accordance with this Exhibit, and is intended to be a mechanism to manage balances in the Transaction Benefit Account and reduce the amount of the financial settlement as of August 31 of each year. The Available Energy Balance is in BCH's favor if positive, and in BPA's favor if negative.

2. Beginning with the first full Treaty Week in September and continuing through to and including the first full Treaty Week in August of the following year, the Available Energy Balance shall be calculated as follows:

   Available Energy Balance = TBA + A - B; where

   "TBA" = Transaction Benefit Account balance (which may be a positive or negative value),

   "A" = The energy value attributed to Head Loss Energy for the prior year ending August 31 (this will be a positive value), subject to Section 3 below, and

   "B" = The energy value attributed to BCH Water Transactions that reduce Arrow outflows where the Parties have made an agreement for BCH to release that water by the upcoming August 31 (this will be a negative value).

3. From the Effective Date through August 31, 2012, the energy value in "A" above shall be equal to $3.4 million.

4. In the time period not covered by that specified in Section 2 above, the Available Energy Balance shall be equal to the Transaction Benefit Account balance.

5. For the purpose of scheduling energy deliveries under Section 6(c) of the Agreement, the Available Energy Balance shall be the balance calculated as of the end of the Treaty Week prior to the week in which the request is made.

Exhibit G
TRANSACTION REQUEST PROTOCOL AND ENERGY SCHEDULING GUIDELINES

1. WATER TRANSACTION COORDINATION AND REQUEST PROTOCOL

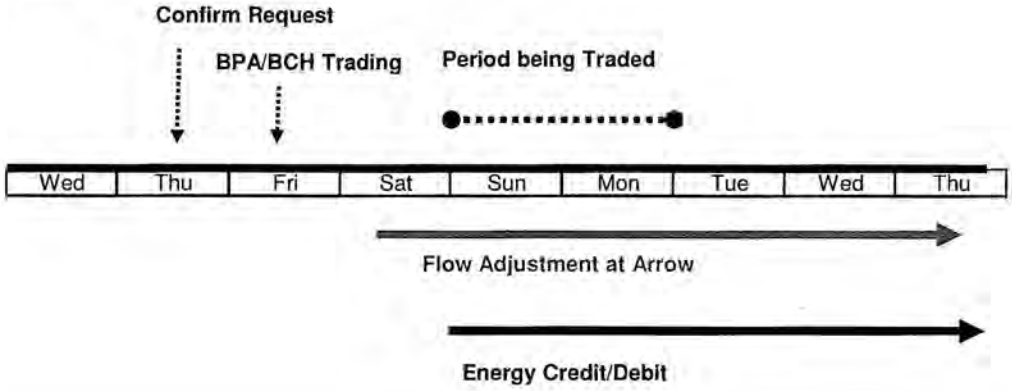
Water Transaction requests pursuant to Section 4(a) of the Agreement shall be coordinated in conjunction with the Weekly Treaty Storage Operation Agreement for the upcoming Treaty Week. On each Thursday, or earlier if needed due to U.S. Federal Government or British Columbia holidays or other scheduling considerations, the Parties shall have a weekly conference call to discuss Water Transaction volumes and accounting for the upcoming Treaty Week. BPA shall, upon request, provide BCH with an estimate of the weekly average Federal h/k or, as appropriate, the weekly average U.S. h/k for the upcoming Treaty Week.

Water Transaction requests shall be made on a flat, weekly basis for the upcoming Treaty week. Water Transactions shall be deemed to begin at 0000 hours on the day for which the Water Transaction is scheduled. The requesting Party shall specify the Water Transaction requested in kcfs.

If all Water Transaction requests for a given week cannot be accommodated, such requests shall be limited in accordance with Section 12 of this Agreement.

All requests must be confirmed by 1200 hours Pacific prevailing time on the day-prior to the day on which BPA would carry out pre-schedule Trading (defined as Confirm Request and BPA Trading as per Example 1 below), as specified by the Western Electric Coordinating Council (WECC) scheduling calendar, or earlier if needed due to U.S. Federal Government or British Columbia holidays or other scheduling considerations, to accommodate Water Transactions that are deemed to have resulted in a change in generation on the Downstream Federal Hydro Projects (See Section 6(b)(3) of the Agreement). Unless otherwise agreed, it is intended that the confirmation of Water Transactions shall be timed such that BPA will have opportunity to carry out energy transactions in pre-scheduled markets to capture and mitigate the changes in economic value of flows through the Downstream Federal Hydro Projects resulting from BCH Water Transactions (see Example 1 below).

Example 1:



2. ENERGY SCHEDULING GUIDELINES

Requests for energy deliveries under this Agreement shall be finalized on the same schedule as Water Transaction requests. All requests must be confirmed by 1200 hours Pacific prevailing time on the day-prior to the day on which BPA and BCH would carry out pre-schedule Trading, as specified by the WECC scheduling calendar, or earlier if needed due to U.S. Federal Government or British Columbia holidays or other scheduling considerations. (See Confirm Request and BPA/BCH Trading as per Example 1.)

The period for which energy schedules shall be requested is the one-week period, lagged by one day, from the Treaty Week. The current Treaty Week is Saturday through Friday, resulting in energy schedules for Sunday through Saturday.

Exhibit H
BRIDGE AGREEMENT RECONCILIATION

1. ACTIVE ACCOUNTS

In accordance with Section 6(a)(2) of the Agreement, each Party's account balance under the Bridge Agreement as of the Effective Date shall be transferred to the Party's Active Account under this Agreement in accordance with the following formula:

Active Account balance = account balance under Bridge Agreement

2. TRANSACTION BENEFIT ACCOUNT

As of the Effective Date: (1) the energy value associated with BCH water transactions and (2) the value of BPA head loss energy, under the Bridge Agreement, will be carried forward to this Agreement, and the Transaction Benefit Account will be initialized to the sum of (1) and (2).

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METHODOLOGY AND SPECIFICATIONS GUIDE

M2MS – POWER METHODOLOGY

Latest update: February 2017

INTRODUCTION

Platts' methodologies are designed to produce forward curves that are representative of market value, and of the particular markets to which they relate. Methodology documents describe the specifications for various products reflected by Platts' Market Data, the processes and standards Platts adheres to in collecting data, and the methods by which Platts arrives at final values for publication. These guides are freely available on Platts' website for public review.

Platts discloses publicly the days of publication for its forward curves, and the times during each trading day in which Platts considers transactions in determining its forward curves. This schedule of publication is available on Platts' website, at the following link: http://www.platts.com/HolidayHome.

The dates of publication and the curve production periods are subject to change in the event of outside circumstances that affect Platts' ability to adhere to its normal publication schedule. Such circumstances include network outages, power failures, acts of terrorism and other situations that result in an interruption in Platts' operations at one or more of its worldwide offices. In the event that any such circumstance occurs, Platts will endeavor, whenever feasible, to communicate publicly any changes to its publication schedule and curve production periods, with as much advance notice as possible.

All Platts methodologies reflect Platts' commitment to maintaining best practices.

Platts' methodologies have evolved to reflect changing market conditions through time, and will continue to evolve as markets change. A revision history, a cumulative summary of changes to this and future updates, is included at the end of the methodology.

How this methodology statement is organized

This description of methodology for forward curves is divided into seven major parts (I-VII) that parallel the entire process of producing the forward curves.

- Part I describes what goes into Platts forward curves, including details on what market data is used.
- Part II describes the security practices that Platts uses in handling and treating data.
- Part III is a detailed account of how Platts collects market data, and what Platts does with the data to formulate its forward curves..
- Part IV explains the process for verifying that published curves comply with Platts' standards.
- Part V lays out the verification and correction process for revising published curves and the criteria Platts uses to determine when it publishes a correction.
- Part VI explains how users of Platts forward curves can contact Platts for clarification of data that has been published, or to register a complaint. It also describes how to find out more about Platts' complaint policies.
- Part VII is a list of detailed specifications for the trading locations and products for which Platts publishes forward curves in this commodity.

PART I: DATA QUALITY AND DATA SUBMISSION

Platts aggregates multiple data sources to produce a single cross-checked series of curves using an open and validated methodology, offering clients a view of forward values that can be used for independent valuation, mark-to-market validation processes, strategic decision support, or other portfolio risk management processes. The product also provides a valuable source of information for evaluating and verifying internally generated values for marking forward positions.

Platts maintains comprehensive historical data on spot and forward prices of individual locations. This dataset is used to define and statistically verify temporal and spatial relationships among the hubs. This data, along with ICE market data, is a primary and critical input into the CRS (Commodity Risk Solutions) quantitative curve generation process and is an asset that is unique to Platts.

Platts and IntercontinentalExchange (ICE) reached an agreement in October 2007 to combine the data-gathering capabilities of each company with Platts' expertise and avowed methodology systems to enhance the rapidly growing forward curve product offerings in North American natural gas and electricity.

Under the agreement Platts incorporates ICE settlement and intra-day forward trading activity in the Electricity markets on the ICE platform, including daily End of Day and Cleared Settlement reports as key inputs into the Platts M2MS (quantitatively derived using settlement prices) curves. Platts benefits from this relationship by having the exclusive right to use ICE intra-day and end of day data for the purposes of forward curve derivation.

General Principles Applicable to All Derivative or Forward Markets

- Forward prices are a reflection of ICE Market Data and are subject to careful review.
- Platts tracks values and interrelationships over the whole course of the day.
- Information is cross-checked to ensure data integrity.
- Illiquid markets may be estimated as spreads relative to active liquid markets.
- Platts gives highest priority to available market data but allows for the use of model data to fill out curves where market data provide no indications.

- Relevant market information is considered even in the development of prices for hubs where no ICE Market Data data is available.

PART II: SECURITY AND CONFIDENTIALITY

Data is stored in a secure network, in accordance with Platts' policies and procedures.

PART III: CALCULATING FORWARD CURVES

The following section describes how Platts uses the transactional data it has collected in the manner described in Part1, to formulate the forward curves.

1. Receive ICE pre-settlement data.

2. Shape ICE settlement data to increase granularity to monthly. The shaping methodology for each curve breaks the package into monthly granularity by combining information from historical forward prices, historical spot prices, and ICE forward prices. When the model is set up, shaping factors are calculated daily to better reflect market conditions. The time horizon used for generating shaping factors is selected to best represent the temporal dimension.

3. Incorporate ICE activity data. Curves are derived by considering available market information from ICE Intra Day and Activity reports. When the information is available in seasonal packages, Platts applies the shaping methodology to generate monthly curves.

4. Extend the curves for Market locations using EIA Electricity Market Forecasts.

5. Derive curves for Proxy locations. The curve is derived based on similarity in seasonal pricing patterns and overall price correlation. This approach necessarily relies on modeling to a greater degree than Market hubs. Platts performs three calculations to estimate these strips:

   a. Proxy hubs are assigned to market hubs based on their similarity in seasonal pricing patterns and overall price correlation.

   b. The price relationship between the pair of hubs is defined and is calculated from the historical data set.

   c. The monthly values for the market hub are used to determine the prices for the proxy hub.

6. Quality assurance and review: In daily production, analysts closely monitor the curve shape to differentiate changes in the term structure from other market activity. We check for outliers, curve abnormalities, and unusual price movements. Curves are later verified with ICE Final Settlement data for consistency.

7. The curves are published and delivered to clients via FTP, Platts.com, channel partners, and/or email.

Shaping

For trading packages that include multiple months, Platts derives a shaping methodology for each month to break the package into monthly granularity by combining information from historical forward prices, historical spot prices, and ICE forward prices.

When the model is set up, shaping factors are calculated daily to better reflect market conditions. The time horizon used for generating shaping factors is selected to best represent the temporal relationship of the forward price with enough data to guarantee the stability of the curve shapes. Monthly shaping will always average to ICE package values.

In daily production, analysts closely monitor the curve shape to differentiate changes in the term structure from other market activity.

Electricity market forecasts and 20 year curves

Platts utilizes electricity price forecasts from the U.S. Energy Information Administration's Electricity Market Forecasts for the purposes of extending curves beyond available market data. For 20 year curves, the first 120 months is consistent with the 120 month M2MS curve of the last trading day of the month. The latter part of the curve is determined by blending the results from electricity market forecasts obtained from the US EIA.

Based on the model and current market fundamentals, Platts includes information inferred from near-term market data onto the farther end. The resulting product is a discrete and smooth curve that gives priority to market data when available but has a robust, consistent process for building prices when market data is not available.

Peak/off-peak conversion

- The daily forward prices that make up the Power Forward Curve are for standard on-peak and off-peak forward products.

- Standard on-peak forward packages in Eastern and Central markets include power delivered during the 16 on-peak hours on weekdays and exclude weekends and holidays defined by the North American Electric Reliability Corp (NERC).

- Standard on-peak forward packages in Western markets include power delivered during the 16 on-peak hours each day Monday through Saturday and exclude Sundays and NERC holidays.

- Standard off-peak forward packages in the Eastern and Central markets markets include power delivered during the eight off-peak hours each weekday and all hours on weekends and NERC holidays.

- Standard off-peak forward packages in the Western markets include power delivered during the eight off-peak hours Monday through Saturday and all hours on Sunday and NERC holidays.

PART IV: PLATTS STANDARDS

All Platts' employees must adhere to the S&P Global Code of Business Ethics (COBE), which has to be signed annually. The COBE reflects S&P Global's commitment to integrity, honesty and acting in good faith in all its dealings.

In addition, Platts requires that all employees attest annually that they do not have any personal relationships or personal financial interests that may influence or be perceived to influence or interfere with their ability to perform their jobs in an objective, impartial and effective manner.

Platts has a Quality & Risk Management (QRM) function that is independent of the Commodity Risk Solutions (CRS) group. QRM is responsible for ensuring the quality and adherence to Platts' policies, standards, processes and procedures. The QRM team conduct regular assessments of CRS operations, including checks for adherence to published methodologies.

S&P Global's internal auditor, an independent group that reports directly to the parent company's board of directors, reviews the Platts risk assessment programs.

PART V: CORRECTIONS

Platts is committed to promptly correcting any material errors. When corrections are made, they are limited to corrections to data that was available when the forward price was calculated.

PART VI: REQUESTS FOR CLARIFICATIONS OF DATA AND COMPLAINTS

Platts strives to provide critical information of the highest standards, to facilitate greater transparency and efficiency in physical commodity markets.

Platts customers raise questions about its methodologies and the approach taken in the formation of forward curves. Platts strongly values these interactions and encourages dialogue concerning any questions a customer or market stakeholder may have.

However, Platts recognizes that occasionally customers may not be satisfied with responses received or the services provided by Platts and wish to escalate matters. Full information about how to contact Platts to request clarification around an assessment, or make a complaint, is available on the Platts website, at: http://www.platts.com/ContactUs/Complaints.

PART VII: DEFINITIONS OF THE NORTH AMERICAN LOCATIONS FOR WHICH PLATTS PUBLISHES FORWARD CURVES

The following M2MS-Power Methodology and Specifications Guide contains the primary specifications and methodologies for Platts Power Forward Curves in North America. The various components of this guide are designed to give Platts subscribers as much information as possible about a wide range of methodology and specification issues.

This methodology is current at the time of publication. Platts may issue further updates and enhancements to this methodology and will communicate these to subscribers through its usual publications of record. Such updates will be included in the next version of the methodology. Platts managers will usually be ready to provide guidance when forward curve issues require clarification.

Platts' Commodity Risk Solutions (CRS) daily 10 year and monthly 20 year M2MS-Power forward curves aim to bring greater price transparency to power forward markets in North America and to provide an independent view of forward peak/off peak power values for multiple power hubs in the US and Canada, including those where there is minimal or no trading activity on any given day. They provide a regionally comprehensive and industry-accepted standard for normalized short-and long-term power contract valuations.

Platts produces M2MS-Power curves at multiple delivery points across North America. We classify our locations into two categories for the purpose of curve production:

- **Market Hubs:** For liquid trading locations at which settlement data is available and verifiable.
- **Proxy Hubs:** For locations where there is little or no market data available. The CRS quantitative methodology uses fundamental analysis and statistical testing to establish a defendable proxy relationship between these hubs and one of the Market hubs defined above.

Each value on a 36-month implied volatility curve is obtained as an annualized standard deviation of the month-to-month returns of the corresponding M2MS forward price, taken over the course of the preceding 12 business months.

Each value on a 36-month heat rate curve is obtained as a ratio between the M2MS-Power and M2MS-Gas forward prices on a particular day. The forward prices used to derive the heat rate refer to a specific pair of Power and Gas hubs and the same delivery month.

Platts M2MS-Power offers the following curves for the North American Power market:

- 120-Month Peak and Off-Peak curves, delivered daily, provide market-based forward price with monthly granularity plus balance of the month for 72 locations. 20-Year Peak and Off-Peak curves, delivered monthly, provide 240-month (20-year) monthly granularity forward curves plus balance of the month for 72 locations, derived by combining the current 120-month regional forward assessments with 20 year annual price projections incorporating market fundamentals. Balance of the month refers to the period beginning from the day after the spot flow date to the last trade date of the month.
- 36-Month implied volatility curves.
- All curves are available in five regional packages (ERCOT, Northeast, PJM/MISO, Southeast, and West).
- A sixth package, M2MS National, contains 22 of the most liquid trading locations in the US and Canada.
- The subscribers to both M2MS-Power and M2MS-Gas packages also obtains heat rates.

Platts Offers Curves for 72 Power Locations in Five Regional Packages and an Optional National Package

Northeast Region	PJM/MISO Region		Southeast Region	ERCOT Region	West Region
ISO-NE NE-Mass	Michigan	PJM METED	Florida	ERCOT Houston Hub	Alberta
ISO-NE New Hampshire	MISO Arkansas Hub	PJM NI Hub	Into Southern	ERCOT North Hub	Calif-Oregon Border
ISO-NE SE-Mass	MISO Illinois Hub	PJM PECO Zone	Into TVA	ERCOT South Hub	East Colorado
ISONE Vermont Zone	MISO Indiana Hub	PJM PENELEC	SPP North	ERCOT West Hub	Four Corners
ISO-NE W Central Mass	MISO Louisiana Hub	PJM PEPCO Zone	SPP South		Mead
NEPOOL Connecticut	MISO Minn Hub	PJM PPL Zone	Vacar		Mid-Columbia
NEPOOL Mass Hub	MISO Texas Hub	PJM PSEG Zone			NOB, Nevada-Oregon Border
NEPOOL North	PJM Rockland Electric Zone	PJM Western Hub			North Path 15
NEPOOL RI	PJM AD Hub				Palo Verde
NY ISO Zone A (West)	PJM AECO				Pinnacle Peak
NYISO Zone B (Genesee)	PJM AEP				South Path 15
NY ISO Zone C (Central)	PJM APS				Utah
NY ISO Zone D (North)	PJM ATSI				
NY ISO Zone F (Capital)	PJM BGE Zone				
NY ISO Zone G (Hudson Val)	PJM ComEd				
NY ISO H (Milwood)	PJM DEOK				
NYISO I (Dunwoodie)	PJM DPL				
NY ISO Zone J (NYC)	PJM Duquesne				
NY ISO Zone K (Long Island)	PJM Eastern Hub				
NY ISO Mohawk Valley Zone (E)	PJM FE Ohio				
Ontario	PJM JCPL Zone				

Optional M2MS-Power National Package includes a cross-section of 22 North America power curves:

M2MS-Power National Package					
ERCOT Houston Hub	Into Southern	MISO Indiana Hub	North Path 15	Ontario	PJM Western Hub
ERCOT North Hub	Mead	MISO Louisiana Hub	NY ISO Zone A (West)	Palo Verde	South Path 15
ERCOT South Hub	Mid-Columbia	MISO Texas Hub	NY ISO Zone G (Hudson Val)	PJM AD Hub	
ERCOT West Hub	MISO Arkansas Hub	NEPOOL Mass Hub	NY ISO Zone J (NYC)	PJM NI Hub	

M2MS-POWER NORTHEAST REGION SYMBOLS FOR 10 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
ISO-NE NE-Mass Opk	Market	ENMCB00	ENMCAyy	ENMCByy	ENMCCyy	ENMCDyy	ENMCEyy	ENMCFyy	ENMCGyy	ENMCHyy	ENMCIyy	ENMCJyy	ENMCKyy	ENMCLyy
ISO-NE NE-Mass Pk	Market	ENMAB00	ENMAAyy	ENMAByy	ENMACyy	ENMADyy	ENMAEyy	ENMAFyy	ENMAGyy	ENMAHyy	ENMAIyy	ENMAJyy	ENMAKyy	ENMALyy
ISO-NE New Hampshire Opk	Market	EHHCB00	EHHCAyy	EHHCByy	EHHCCyy	EHHCDyy	EHHCEyy	EHHCFyy	EHHCGyy	EHHCHyy	EHHCIyy	EHHCJyy	EHHCKyy	EHHCLyy
ISO-NE New Hampshire Pk	Market	EHHAB00	EHHAAyy	EHHAByy	EHHACyy	EHHADyy	EHHAEyy	EHHAFyy	EHHAGyy	EHHAHyy	EHHAIyy	EHHAJyy	EHHAKyy	EHHALyy
ISO-NE SE-MASS Opk	Market	ESMCB00	ESMCAyy	ESMCByy	ESMCCyy	ESMCDyy	ESMCEyy	ESMCFyy	ESMCGyy	ESMCHyy	ESMCIyy	ESMCJyy	ESMCKyy	ESMCLyy
ISO-NE SE-MASS Pk	Market	ESMAB00	ESMAAyy	ESMAByy	ESMACyy	ESMADyy	ESMAEyy	ESMAFyy	ESMAGyy	ESMAHyy	ESMAIyy	ESMAJyy	ESMAKyy	ESMALyy
ISONE Vermont Zone Opk	Proxy	EVMCB00	EVMCAyy	EVMCByy	EVMCCyy	EVMCDyy	EVMCEyy	EVMCFyy	EVMCGyy	EVMCHyy	EVMCIyy	EVMCJyy	EVMCKyy	EVMCLyy
ISONE Vermont Zone Pk	Proxy	EVMAB00	EVMAAyy	EVMAByy	EVMACyy	EVMADyy	EVMAEyy	EVMAFyy	EVMAGyy	EVMAHyy	EVMAIyy	EVMAJyy	EVMAKyy	EVMALyy
ISO-NE W Central Mass Opk	Market	EMMCB00	EMMCAyy	EMMCByy	EMMCCyy	EMMCDyy	EMMCEyy	EMMCFyy	EMMCGyy	EMMCHyy	EMMCIyy	EMMCJyy	EMMCKyy	EMMCLyy
ISO-NE W Central Mass Pk	Market	EMMAB00	EMMAAyy	EMMAByy	EMMACyy	EMMADyy	EMMAEyy	EMMAFyy	EMMAGyy	EMMAHyy	EMMAIyy	EMMAJyy	EMMAKyy	EMMALyy
NEPOOL Mass Hub Opk	Market	EMHOB00	EMHOAyy	EMHOByy	EMHOCyy	EMHODyy	EMHOEyy	EMHOFyy	EMHOGyy	EMHOHyy	EMHOIyy	EMHOJyy	EMHOKyy	EMHOLyy
NEPOOL Mass Hub Pk	Market	EMHMB00	EMHMAyy	EMHMByy	EMHMCyy	EMHMDyy	EMHMEyy	EMHMFyy	EMHMGyy	EMHMHyy	EMHMIyy	EMHMJyy	EMHMKyy	EMHMLyy
NEPOOL-CT Opk	Market	ENCOB00	ENCOAyy	ENCOByy	ENCOCyy	ENCODyy	ENCOEyy	ENCOFyy	ENCOGyy	ENCOHyy	ENCOIyy	ENCOJyy	ENCOKyy	ENCOLyy
NEPOOL-CT Pk	Market	ENCMB00	ENCMAyy	ENCMByy	ENCMCyy	ENCMDyy	ENCMEyy	ENCMFyy	ENCMGyy	ENCMHyy	ENCMIyy	ENCMJyy	ENCMKyy	ENCMLyy
NEPOOL-North Opk	Market	ENNOB00	ENNOAyy	ENNOByy	ENNOCyy	ENNODyy	ENNOEyy	ENNOFyy	ENNOGyy	ENNOHyy	ENNOIyy	ENNOJyy	ENNOKyy	ENNOLyy
NEPOOL-North Pk	Market	ENNMB00	ENNMAyy	ENNMByy	ENNMCyy	ENNMDyy	ENNMEyy	ENNMFyy	ENNMGyy	ENNMHyy	ENNMIyy	ENNMJyy	ENNMKyy	ENNMLyy
NEPOOL-RI Opk	Proxy	ENROB00	ENROAyy	ENROByy	ENROCyy	ENRODyy	ENROEyy	ENROFyy	ENROGyy	ENROHyy	ENROIyy	ENROJyy	ENROKyy	ENROLyy
NEPOOL-RI Pk	Proxy	ENRMB00	ENRMAyy	ENRMByy	ENRMCyy	ENRMDyy	ENRMEyy	ENRMFyy	ENRMGyy	ENRMHyy	ENRMIyy	ENRMJyy	ENRMKyy	ENRMLyy
NY ISO B (Genesee) Opk	Proxy	ENBQB00	ENBQAyy	ENBQByy	ENBQCyy	ENBQDyy	ENBQEyy	ENBQFyy	ENBQGyy	ENBQHyy	ENBQIyy	ENBQJyy	ENBQKyy	ENBQLyy
NY ISO B (Genesee) Pk	Proxy	ENBPB00	ENBPAyy	ENBPByy	ENBPCyy	ENBPDyy	ENBPEyy	ENBPFyy	ENBPGyy	ENBPHyy	ENBPIyy	ENBPJyy	ENBPKyy	ENBPLyy
NY ISO H (Milwood) Opk	Proxy	ENHQB00	ENHQAyy	ENHQByy	ENHQCyy	ENHQDyy	ENHQEyy	ENHQFyy	ENHQGyy	ENHQHyy	ENHQIyy	ENHQJyy	ENHQKyy	ENHQLyy
NY ISO H (Milwood) Pk	Proxy	ENHPB00	ENHPAyy	ENHPByy	ENHPCyy	ENHPDyy	ENHPEyy	ENHPFyy	ENHPGyy	ENHPHyy	ENHPIyy	ENHPJyy	ENHPKyy	ENHPLyy
NY ISO Mohawk Valley Zone (E) Opk	Proxy	ENECB00	ENECAyy	ENECByy	ENECCyy	ENECDyy	ENECEyy	ENECFyy	ENECGyy	ENECHyy	ENECIyy	ENECJyy	ENECKyy	ENECLyy
NY ISO Mohawk Valley Zone (E) Pk	Proxy	ENEAB00	ENEAAyy	ENEAByy	ENEACyy	ENEADyy	ENEAEyy	ENEAFyy	ENEAGyy	ENEAHyy	ENEAIyy	ENEAJyy	ENEAKyy	ENEALyy
NY ISO Zone A (West) Opk	Market	ENAOB00	ENAOAyy	ENAOByy	ENAOCyy	ENAODyy	ENAOEyy	ENAOFyy	ENAOGyy	ENAOHyy	ENAOIyy	ENAOJyy	ENAOKyy	ENAOLyy
NY ISO Zone A (West) Pk	Market	ENAMB00	ENAMAyy	ENAMByy	ENAMCyy	ENAMDyy	ENAMEyy	ENAMFyy	ENAMGyy	ENAMHyy	ENAMIyy	ENAMJyy	ENAMKyy	ENAMLyy
NY ISO Zone C (Central) Opk	Market	ECNCB00	ECNCAyy	ECNCByy	ECNCCyy	ECNCDyy	ECNCEyy	ECNCFyy	ECNCGyy	ECNCHyy	ECNCIyy	ECNCJyy	ECNCKyy	ECNCLyy
NY ISO Zone C (Central) Pk	Market	ECNAB00	ECNAAyy	ECNAByy	ECNACyy	ECNADyy	ECNAEyy	ECNAFyy	ECNAGyy	ECNAHyy	ECNAIyy	ECNAJyy	ECNAKyy	ECNALyy
NY ISO Zone D (North) Opk	Market	ENDOB00	ENDOAyy	ENDOByy	ENDOCyy	ENDODyy	ENDOEyy	ENDOFyy	ENDOGyy	ENDOHyy	ENDOIyy	ENDOJyy	ENDOKyy	ENDOLyy
NY ISO Zone D (North) Pk	Market	ENDMB00	ENDMAyy	ENDMByy	ENDMCyy	ENDMDyy	ENDMEyy	ENDMFyy	ENDMGyy	ENDMHyy	ENDMIyy	ENDMJyy	ENDMKyy	ENDMLyy
NY ISO Zone F (Capital) Opk	Market	EFNCB00	EFNCAyy	EFNCByy	EFNCCyy	EFNCDyy	EFNCEyy	EFNCFyy	EFNCGyy	EFNCHyy	EFNCIyy	EFNCJyy	EFNCKyy	EFNCLyy
NY ISO Zone F (Capital) Pk	Market	EFNAB00	EFNAAyy	EFNAByy	EFNACyy	EFNADyy	EFNAEyy	EFNAFyy	EFNAGyy	EFNAHyy	EFNAIyy	EFNAJyy	EFNAKyy	EFNALyy
NY ISO Zone G (Hudson Val) Opk	Market	ENGOB00	ENGOAyy	ENGOByy	ENGOCyy	ENGODyy	ENGOEyy	ENGOFyy	ENGOGyy	ENGOHyy	ENGOIyy	ENGOJyy	ENGOKyy	ENGOLyy
NY ISO Zone G (Hudson Val) Pk	Market	ENGMB00	ENGMAyy	ENGMByy	ENGMCyy	ENGMDyy	ENGMEyy	ENGMFyy	ENGMGyy	ENGMHyy	ENGMIyy	ENGMJyy	ENGMKyy	ENGMLyy
NY ISO Zone J (NYC) Opk	Market	ENJOB00	ENJOAyy	ENJOByy	ENJOCyy	ENJODyy	ENJOEyy	ENJOFyy	ENJOGyy	ENJOHyy	ENJOIyy	ENJOJyy	ENJOKyy	ENJOLyy
NY ISO Zone J (NYC) Pk	Market	ENJMB00	ENJMAyy	ENJMByy	ENJMCyy	ENJMDyy	ENJMEyy	ENJMFyy	ENJMGyy	ENJMHyy	ENJMIyy	ENJMJyy	ENJMKyy	ENJMLyy
NY ISO Zone K (Long Island) Opk	Proxy	ENKOB00	ENKOAyy	ENKOByy	ENKOCyy	ENKODyy	ENKOEyy	ENKOFyy	ENKOGyy	ENKOHyy	ENKOIyy	ENKOJyy	ENKOKyy	ENKOLyy
NY ISO Zone K (Long Island) Pk	Proxy	ENKMB00	ENKMAyy	ENKMByy	ENKMCyy	ENKMDyy	ENKMEyy	ENKMFyy	ENKMGyy	ENKMHyy	ENKMIyy	ENKMJyy	ENKMKyy	ENKMLyy
NYISO I (Dunwoodie) Opk	Proxy	EINQB00	EINQAyy	EINQByy	EINQCyy	EINQDyy	EINQEyy	EINQFyy	EINQGyy	EINQHyy	EINQIyy	EINQJyy	EINQKyy	EINQLyy
NYISO I (Dunwoodie) Pk	Proxy	EINPB00	EINPAyy	EINPByy	EINPCyy	EINPDyy	EINPEyy	EINPFyy	EINPGyy	EINPHyy	EINPIyy	EINPJyy	EINPKyy	EINPLyy
Ontario Opk	Market	EONOB00	EONOAyy	EONOByy	EONOCyy	EONODyy	EONOEyy	EONOFyy	EONOGyy	EONOHyy	EONOIyy	EONOJyy	EONOKyy	EONOLyy
Ontario Pk	Market	EONMB00	EONMAyy	EONMByy	EONMCyy	EONMDyy	EONMEyy	EONMFyy	EONMGyy	EONMHyy	EONMIyy	EONMJyy	EONMKyy	EONMLyy

* The symbols in this table are displayed in summation notation. For example, to derive the symbol for ISO-NE NE-Mass Hub Pk January 2017, replace the yy inENMBAyy from the table above with 17 to make ENMBA17.

M2MS-POWER NORTHEAST REGION SYMBOLS FOR 20 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
ISO-NE NE-Mass Opk	Market	ENMDB00	ENMDAyy	ENMDByy	ENMDCyy	ENMDDyy	ENMDEyy	ENMDFyy	ENMDGyy	ENMDHyy	ENMDIyy	ENMDJyy	ENMDKyy	ENMDLyy
ISO-NE NE-Mass Pk	Market	ENMBB00	ENMBAyy	ENMBByy	ENMBCyy	ENMBDyy	ENMBEyy	ENMBFyy	ENMBGyy	ENMBHyy	ENMBIyy	ENMBJyy	ENMBKyy	ENMBLyy
ISO-NE New Hampshire Opk	Market	EHHDB00	EHHDAyy	EHHDByy	EHHDCyy	EHHDDyy	EHHDEyy	EHHDFyy	EHHDGyy	EHHDHyy	EHHDIyy	EHHDJyy	EHHDKyy	EHHDLyy
ISO-NE New Hampshire Pk	Market	EHHBB00	EHHBAyy	EHHBByy	EHHBCyy	EHHBDyy	EHHBEyy	EHHBFyy	EHHBGyy	EHHBHyy	EHHBIyy	EHHBJyy	EHHBKyy	EHHBLyy
ISO-NE SE-MASS Opk	Market	ESMDB00	ESMDAyy	ESMDByy	ESMDCyy	ESMDDyy	ESMDEyy	ESMDFyy	ESMDGyy	ESMDHyy	ESMDIyy	ESMDJyy	ESMDKyy	ESMDLyy
ISO-NE SE-MASS Pk	Market	ESMBB00	ESMBAyy	ESMBByy	ESMBCyy	ESMBDyy	ESMBEyy	ESMBFyy	ESMBGyy	ESMBHyy	ESMBIyy	ESMBJyy	ESMBKyy	ESMBLyy
ISONE Vermont Zone Opk	Proxy	EVMDB00	EVMDAyy	EVMDByy	EVMDCyy	EVMDDyy	EVMDEyy	EVMDFyy	EVMDGyy	EVMDHyy	EVMDIyy	EVMDJyy	EVMDKyy	EVMDLyy
ISONE Vermont Zone Pk	Proxy	EVMBB00	EVMBAyy	EVMBByy	EVMBCyy	EVMBDyy	EVMBEyy	EVMBFyy	EVMBGyy	EVMBHyy	EVMBIyy	EVMBJyy	EVMBKyy	EVMBLyy
ISO-NE W Central Mass Opk	Market	EMMDB00	EMMDAyy	EMMDByy	EMMDCyy	EMMDDyy	EMMDEyy	EMMDFyy	EMMDGyy	EMMDHyy	EMMDIyy	EMMDJyy	EMMDKyy	EMMDLyy
ISO-NE W Central Mass Pk	Market	EMMBB00	EMMBAyy	EMMBByy	EMMBCyy	EMMBDyy	EMMBEyy	EMMBFyy	EMMBGyy	EMMBHyy	EMMBIyy	EMMBJyy	EMMBKyy	EMMBLyy
NEPOOL Mass Hub Opk	Market	EMHQB00	EMHQAyy	EMHQByy	EMHQCyy	EMHQDyy	EMHQEyy	EMHQFyy	EMHQGyy	EMHQHyy	EMHQIyy	EMHQJyy	EMHQKyy	EMHQLyy
NEPOOL Mass Hub Pk	Market	EMHPB00	EMHPAyy	EMHPByy	EMHPCyy	EMHPDyy	EMHPEyy	EMHPFyy	EMHPGyy	EMHPHyy	EMHPIyy	EMHPJyy	EMHPKyy	EMHPLyy
NEPOOL-CT Opk	Market	ENCQB00	ENCQAyy	ENCQByy	ENCQCyy	ENCQDyy	ENCQEyy	ENCQFyy	ENCQGyy	ENCQHyy	ENCQIyy	ENCQJyy	ENCQKyy	ENCQLyy
NEPOOL-CT Pk	Market	ENCPB00	ENCPAyy	ENCPByy	ENCPCyy	ENCPDyy	ENCPEyy	ENCPFyy	ENCPGyy	ENCPHyy	ENCPIyy	ENCPJyy	ENCPKyy	ENCPLyy
NEPOOL-North Opk	Market	ENNQB00	ENNQAyy	ENNQByy	ENNQCyy	ENNQDyy	ENNQEyy	ENNQFyy	ENNQGyy	ENNQHyy	ENNQIyy	ENNQJyy	ENNQKyy	ENNQLyy
NEPOOL-North Pk	Market	ENNPB00	ENNPAyy	ENNPByy	ENNPCyy	ENNPDyy	ENNPEyy	ENNPFyy	ENNPGyy	ENNPHyy	ENNPIyy	ENNPJyy	ENNPKyy	ENNPLyy
NEPOOL-RI Opk	Proxy	ENRQB00	ENRQAyy	ENRQByy	ENRQCyy	ENRQDyy	ENRQEyy	ENRQFyy	ENRQGyy	ENRQHyy	ENRQIyy	ENRQJyy	ENRQKyy	ENRQLyy
NEPOOL-RI Pk	Proxy	ENRPB00	ENRPAyy	ENRPByy	ENRPCyy	ENRPDyy	ENRPEyy	ENRPFyy	ENRPGyy	ENRPHyy	ENRPIyy	ENRPJyy	ENRPKyy	ENRPLyy
NY ISO B (Genesee) Opk	Proxy	ENBOB00	ENBOAyy	ENBOByy	ENBOCyy	ENBODyy	ENBOEyy	ENBOFyy	ENBOGyy	ENBOHyy	ENBOIyy	ENBOJyy	ENBOKyy	ENBOLyy
NY ISO B (Genesee) Pk	Proxy	ENBMB00	ENBMAyy	ENBMByy	ENBMCyy	ENBMDyy	ENBMEyy	ENBMFyy	ENBMGyy	ENBMHyy	ENBMIyy	ENBMJyy	ENBMKyy	ENBMLyy
NY ISO H (Milwood) Opk	Proxy	ENHOB00	ENHOAyy	ENHOByy	ENHOCyy	ENHODyy	ENHOEyy	ENHOFyy	ENHOGyy	ENHOHyy	ENHOIyy	ENHOJyy	ENHOKyy	ENHOLyy
NY ISO H (Milwood) Pk	Proxy	ENHMB00	ENHMAyy	ENHMByy	ENHMCyy	ENHMDyy	ENHMEyy	ENHMFyy	ENHMGyy	ENHMHyy	ENHMIyy	ENHMJyy	ENHMKyy	ENHMLyy
NY ISO Mohawk Valley Zone (E) Opk	Proxy	ENEDB00	ENEDAyy	ENEDByy	ENEDCyy	ENEDDyy	ENEDEyy	ENEDFyy	ENEDGyy	ENEDHyy	ENEDIyy	ENEDJyy	ENEDKyy	ENEDLyy
NY ISO Mohawk Valley Zone (E) Pk	Proxy	ENEBB00	ENEBAyy	ENEBByy	ENEBCyy	ENEBDyy	ENEBEyy	ENEBFyy	ENEBGyy	ENEBHyy	ENEBIyy	ENEBJyy	ENEBKyy	ENEBLyy
NY ISO Zone A (West) Opk	Market	ENAQB00	ENAQAyy	ENAQByy	ENAQCyy	ENAQDyy	ENAQEyy	ENAQFyy	ENAQGyy	ENAQHyy	ENAQIyy	ENAQJyy	ENAQKyy	ENAQLyy
NY ISO Zone A (West) Pk	Market	ENAPB00	ENAPAyy	ENAPByy	ENAPCyy	ENAPDyy	ENAPEyy	ENAPFyy	ENAPGyy	ENAPHyy	ENAPIyy	ENAPJyy	ENAPKyy	ENAPLyy
NY ISO Zone C (Central) Opk	Market	ECNDB00	ECNDAyy	ECNDByy	ECNDCyy	ECNDDyy	ECNDEyy	ECNDFyy	ECNDGyy	ECNDHyy	ECNDIyy	ECNDJyy	ECNDKyy	ECNDLyy
NY ISO Zone C (Central) Pk	Market	ECNBB00	ECNBAyy	ECNBByy	ECNBCyy	ECNBDyy	ECNBEyy	ECNBFyy	ECNBGyy	ECNBHyy	ECNBIyy	ECNBJyy	ECNBKyy	ECNBLyy
NY ISO Zone D (North) Opk	Market	ENDQB00	ENDQAyy	ENDQByy	ENDQCyy	ENDQDyy	ENDQEyy	ENDQFyy	ENDQGyy	ENDQHyy	ENDQIyy	ENDQJyy	ENDQKyy	ENDQLyy
NY ISO Zone D (North) Pk	Market	ENDPB00	ENDPAyy	ENDPByy	ENDPCyy	ENDPDyy	ENDPEyy	ENDPFyy	ENDPGyy	ENDPHyy	ENDPIyy	ENDPJyy	ENDPKyy	ENDPLyy
NY ISO Zone F (Capital) Opk	Market	EFNDB00	EFNDAyy	EFNDByy	EFNDCyy	EFNDDyy	EFNDEyy	EFNDFyy	EFNDGyy	EFNDHyy	EFNDIyy	EFNDJyy	EFNDKyy	EFNDLyy
NY ISO Zone F (Capital) Pk	Market	EFNBB00	EFNBAyy	EFNBByy	EFNBCyy	EFNBDyy	EFNBEyy	EFNBFyy	EFNBGyy	EFNBHyy	EFNBIyy	EFNBJyy	EFNBKyy	EFNBLyy
NY ISO Zone G (Hudson Val) Opk	Market	ENGQB00	ENGQAyy	ENGQByy	ENGQCyy	ENGQDyy	ENGQEyy	ENGQFyy	ENGQGyy	ENGQHyy	ENGQIyy	ENGQJyy	ENGQKyy	ENGQLyy
NY ISO Zone G (Hudson Val) Pk	Market	ENGPB00	ENGPAyy	ENGPByy	ENGPCyy	ENGPDyy	ENGPEyy	ENGPFyy	ENGPGyy	ENGPHyy	ENGPIyy	ENGPJyy	ENGPKyy	ENGPLyy
NY ISO Zone J (NYC) Opk	Market	ENJQB00	ENJQAyy	ENJQByy	ENJQCyy	ENJQDyy	ENJQEyy	ENJQFyy	ENJQGyy	ENJQHyy	ENJQIyy	ENJQJyy	ENJQKyy	ENJQLyy
NY ISO Zone J (NYC) Pk	Market	ENJPB00	ENJPAyy	ENJPByy	ENJPCyy	ENJPDyy	ENJPEyy	ENJPFyy	ENJPGyy	ENJPHyy	ENJPIyy	ENJPJyy	ENJPKyy	ENJPLyy
NY ISO Zone K (Long Island) Opk	Proxy	ENKQB00	ENKQAyy	ENKQByy	ENKQCyy	ENKQDyy	ENKQEyy	ENKQFyy	ENKQGyy	ENKQHyy	ENKQIyy	ENKQJyy	ENKQKyy	ENKQLyy
NY ISO Zone K (Long Island) Pk	Proxy	ENKPB00	ENKPAyy	ENKPByy	ENKPCyy	ENKPDyy	ENKPEyy	ENKPFyy	ENKPGyy	ENKPHyy	ENKPIyy	ENKPJyy	ENKPKyy	ENKPLyy
NYISO I (Dunwoodie) Opk	Proxy	EINOB00	EINOAyy	EINOByy	EINOCyy	EINODyy	EINOEyy	EINOFyy	EINOGyy	EINOHyy	EINOIyy	EINOJyy	EINOKyy	EINOLyy
NYISO I (Dunwoodie) Pk	Proxy	EINMB00	EINMAyy	EINMByy	EINMCyy	EINMDyy	EINMEyy	EINMFyy	EINMGyy	EINMHyy	EINMIyy	EINMJyy	EINMKyy	EINMLyy
Ontario Opk	Market	EONQB00	EONQAyy	EONQByy	EONQCyy	EONQDyy	EONQEyy	EONQFyy	EONQGyy	EONQHyy	EONQIyy	EONQJyy	EONQKyy	EONQLyy
Ontario Pk	Market	EONPB00	EONPAyy	EONPByy	EONPCyy	EONPDyy	EONPEyy	EONPFyy	EONPGyy	EONPHyy	EONPIyy	EONPJyy	EONPKyy	EONPLyy

* The symbols in this table are displayed in summation notation. For example, to derive the symbol for ISO-NE NE-Mass Hub Pk January 2017, replace the yy inENMBAyy from the table above with 17 to make ENMBA17.

NORTHEAST REGION

ISO-NE NE-Mass
NE-Mass, or Northeast Mass, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by ISO-NE on their website www.iso-ne.com.

ISO-NE New Hampshire
ISO-NE New Hampshire is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by ISO-NE on their website www.iso-ne.com.

ISO-NE SE-Mass
SE-Mass, or Southeast Mass, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by ISO-NE on their website www.iso-ne.com.

ISO-NE Vermont Zone
ISO-NE Vermont Zone is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by ISO-NE on their website www.iso-ne.com.

ISO-NE W Central Mass
W Central Mass, or West Central Mass, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by ISO-NE on their website www.iso-ne.com.

NEPOOL Connecticut
NEPOOL Connecticut, or ISO-NE Connecticut, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by ISO-NE on their website www.iso-ne.com.

NEPOOL Mass Hub
NEPOOL Mass Hub, or ISO-NE Mass Hub, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by ISO-NE on their website www.iso-ne.com.

NEPOOL North
NEPOOL North, or ISO-NE Maine, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by ISO-NE on their website www.iso-ne.com.

NEPOOL RI
NEPOOL RI, or ISO-NE Rhode Island, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by ISO-NE on their website www.iso-ne.com.

NY ISO Zone A (West)
NY ISO Zone A, or West Zone, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by NYISO on their website www.nyiso.com.

NYISO Zone B (Genesee)
NYISO Zone B, or Gennesee Zone is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by NYISO on their website www.nyiso.com.

NY ISO Zone C (Central)
NY ISO Zone C, or Central Zone, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by NYISO on their website www.nyiso.com.

NY ISO Zone D (North)
NY ISO Zone D, or North Zone, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by NYISO on their website www.nyiso.com.

NY ISO Zone F (Capital)
NY ISO Zone F, or Capital Zone, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by NYISO on their website www.nyiso.com.

NY ISO Zone G (Hudson Val)
NY ISO Zone G, or Hudson Valley Zone, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by NYISO on their website www.nyiso.com.

NY ISO H (Milwood)
NYISO H, or MIlwood Zone, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by NYISO on their website www.nyiso.com.

NYISO I (Dunwoodie)
NYISO I , or Dunwoodie Zone, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by NYISO on their website www.nyiso.com.**NY ISO Zone J (NYC)**

NYISO Zone J (NYC)
NY ISO Zone J, or New York City Zone, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by NYISO on their website www.nyiso.com.

NY ISO Zone K (Long Island)
NY ISO Zone K, or Long Island Zone, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by NYISO on their website www.nyiso.com.

NY ISO Mohawk Valley Zone (E)
NY ISO Zone E, or Mohawk Valley Zone, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by NYISO on their website www.nyiso.com.

Ontario
The Ontario market and pricing area comprises the grid controlled by Ontario's independent system operator, the Independent Electricity System Operator (IESO).

M2MS-POWER PJM/MISO REGION SYMBOLS FOR 10 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
Michigan Opk	Market	EMIOB00	EMIOAyy	EMIOByy	EMIOCyy	EMIODyy	EMIOEyy	EMIOFyy	EMIOGyy	EMIOHyy	EMIOIyy	EMIOJyy	EMIOKyy	EMIOLyy
Michigan Pk	Market	EMIMB00	EMIMAyy	EMIMByy	EMIMCyy	EMIMDyy	EMIMEyy	EMIMFyy	EMIMGyy	EMIMHyy	EMIMIyy	EMIMJyy	EMIMKyy	EMIMLyy
Minn Hub Opk	Market	EPMOB00	EPMOAyy	EPMOByy	EPMOCyy	EPMODyy	EPMOEyy	EPMOFyy	EPMOGyy	EPMOHyy	EPMOIyy	EPMOJyy	EPMOKyy	EPMOLyy
Minn Hub Pk	Market	EPMMB00	EPMMAyy	EPMMByy	EPMMCyy	EPMMDyy	EPMMEyy	EPMMFyy	EPMMGyy	EPMMHyy	EPMMIyy	EPMMJyy	EPMMKyy	EPMMLyy
MISO Arkansas Hub Opk	Market	EMACB00	EMACAyy	EMACByy	EMACCyy	EMACDyy	EMACEyy	EMACFyy	EMACGyy	EMACHyy	EMACIyy	EMACJyy	EMACKyy	EMACLyy
MISO Arkansas Hub Pk	Market	EMAAB00	EMAAAyy	EMAAByy	EMAACyy	EMAADyy	EMAAEyy	EMAAFyy	EMAAGyy	EMAAHyy	EMAAIyy	EMAAJyy	EMAAKyy	EMAALyy
MISO Illinois Hub Opk	Market	EILCB00	EILCAyy	EILCByy	EILCCyy	EILCDyy	EILCEyy	EILCFyy	EILCGyy	EILCHyy	EILCIyy	EILCJyy	EILCKyy	EILCLyy
MISO Illinois Hub Pk	Market	EILAB00	EILAAyy	EILAByy	EILACyy	EILADyy	EILAEyy	EILAFyy	EILAGyy	EILAHyy	EILAIyy	EILAJyy	EILAKyy	EILALyy
MISO Indiana Opk	Market	ECIOB00	ECIOAyy	ECIOByy	ECIOCyy	ECIODyy	ECIOEyy	ECIOFyy	ECIOGyy	ECIOHyy	ECIOIyy	ECIOJyy	ECIOKyy	ECIOLyy
MISO Indiana Pk	Market	ECIMB00	ECIMAyy	ECIMByy	ECIMCyy	ECIMDyy	ECIMEyy	ECIMFyy	ECIMGyy	ECIMHyy	ECIMIyy	ECIMJyy	ECIMKyy	ECIMLyy
MISO Louisiana Opk	Market	EMLCB00	EMLCAyy	EMLCByy	EMLCCyy	EMLCDyy	EMLCEyy	EMLCFyy	EMLCGyy	EMLCHyy	EMLCIyy	EMLCJyy	EMLCKyy	EMLCLyy
MISO Louisiana Pk	Market	EMLAB00	EMLAAyy	EMLAByy	EMLACyy	EMLADyy	EMLAEyy	EMLAFyy	EMLAGyy	EMLAHyy	EMLAIyy	EMLAJyy	EMLAKyy	EMLALyy
MISO Texas Hub Opk	Market	EMECB00	EMECAyy	EMECByy	EMECCyy	EMECDyy	EMECEyy	EMECFyy	EMECGyy	EMECHyy	EMECIyy	EMECJyy	EMECKyy	EMECLyy
MISO Texas Hub Pk	Market	EMEAB00	EMEAAyy	EMEAByy	EMEACyy	EMEADyy	EMEAEyy	EMEAFyy	EMEAGyy	EMEAHyy	EMEAIyy	EMEAJyy	EMEAKyy	EMEALyy
PJM AD Hub Opk	Market	EECOB00	EECOAyy	EECOByy	EECOCyy	EECODyy	EECOEyy	EECOFyy	EECOGyy	EECOHyy	EECOIyy	EECOJyy	EECOKyy	EECOLyy
PJM AD Hub Pk	Market	EECMB00	EECMAyy	EECMByy	EECMCyy	EECMDyy	EECMEyy	EECMFyy	EECMGyy	EECMHyy	EECMIyy	EECMJyy	EECMKyy	EECMLyy
PJM AECO Opk	Market	EJACB00	EJACAyy	EJACByy	EJACCyy	EJACDyy	EJACEyy	EJACFyy	EJACGyy	EJACHyy	EJACIyy	EJACJyy	EJACKyy	EJACLyy
PJM AECO Pk	Market	EJAAB00	EJAAAyy	EJAAByy	EJAACyy	EJAADyy	EJAAEyy	EJAAFyy	EJAAGyy	EJAAHyy	EJAAIyy	EJAAJyy	EJAAKyy	EJAALyy
PJM AEP Opk	Market	EJEOB00	EJEOAyy	EJEOByy	EJEOCyy	EJEODyy	EJEOEyy	EJEOFyy	EJEOGyy	EJEOHyy	EJEOIyy	EJEOJyy	EJEOKyy	EJEOLyy
PJM AEP Pk	Market	EJEMB00	EJEMAyy	EJEMByy	EJEMCyy	EJEMDyy	EJEMEyy	EJEMFyy	EJEMGyy	EJEMHyy	EJEMIyy	EJEMJyy	EJEMKyy	EJEMLyy
PJM APS Opk	Market	EJSCB00	EJSCAyy	EJSCByy	EJSCCyy	EJSCDyy	EJSCEyy	EJSCFyy	EJSCGyy	EJSCHyy	EJSCIyy	EJSCJyy	EJSCKyy	EJSCLyy
PJM APS Pk	Market	EJSAB00	EJSAAyy	EJSAByy	EJSACyy	EJSADyy	EJSAEyy	EJSAFyy	EJSAGyy	EJSAHyy	EJSAIyy	EJSAJyy	EJSAKyy	EJSALyy
PJM ATSI Opk	Market	EJTOB00	EJTOAyy	EJTOByy	EJTOCyy	EJTODyy	EJTOEyy	EJTOFyy	EJTOGyy	EJTOHyy	EJTOIyy	EJTOJyy	EJTOKyy	EJTOLyy
PJM ATSI Pk	Market	EJTMB00	EJTMAyy	EJTMByy	EJTMCyy	EJTMDyy	EJTMEyy	EJTMFyy	EJTMGyy	EJTMHyy	EJTMIyy	EJTMJyy	EJTMKyy	EJTMLyy
PJM BGE Zone Opk	Market	EBGOB00	EBGOAyy	EBGOByy	EBGOCyy	EBGODyy	EBGOEyy	EBGOFyy	EBGOGyy	EBGOHyy	EBGOIyy	EBGOJyy	EBGOKyy	EBGOLyy
PJM BGE Zone Pk	Market	EBGMB00	EBGMAyy	EBGMByy	EBGMCyy	EBGMDyy	EBGMEyy	EBGMFyy	EBGMGyy	EBGMHyy	EBGMIyy	EBGMJyy	EBGMKyy	EBGMLyy
PJM ComEd Opk	Market	EJOCB00	EJOCAyy	EJOCByy	EJOCCyy	EJOCDyy	EJOCEyy	EJOCFyy	EJOCGyy	EJOCHyy	EJOCIyy	EJOCJyy	EJOCKyy	EJOCLyy
PJM ComEd Pk	Market	EJOAB00	EJOAAyy	EJOAByy	EJOACyy	EJOADyy	EJOAEyy	EJOAFyy	EJOAGyy	EJOAHyy	EJOAIyy	EJOAJyy	EJOAKyy	EJOALyy
PJM DEOK Opk	Market	EJKOB00	EJKOAyy	EJKOByy	EJKOCyy	EJKODyy	EJKOEyy	EJKOFyy	EJKOGyy	EJKOHyy	EJKOIyy	EJKOJyy	EJKOKyy	EJKOLyy
PJM DEOK Pk	Market	EJKMB00	EJKMAyy	EJKMByy	EJKMCyy	EJKMDyy	EJKMEyy	EJKMFyy	EJKMGyy	EJKMHyy	EJKMIyy	EJKMJyy	EJKMKyy	EJKMLyy
PJM DPL Opk	Market	EJDCB00	EJDCAyy	EJDCByy	EJDCCyy	EJDCDyy	EJDCEyy	EJDCFyy	EJDCGyy	EJDCHyy	EJDCIyy	EJDCJyy	EJDCKyy	EJDCLyy
PJM DPL Pk	Market	EJDAB00	EJDAAyy	EJDAByy	EJDACyy	EJDADyy	EJDAEyy	EJDAFyy	EJDAGyy	EJDAHyy	EJDAIyy	EJDAJyy	EJDAKyy	EJDALyy
PJM Duquesne Opk	Market	EJUCB00	EJUCAyy	EJUCByy	EJUCCyy	EJUCDyy	EJUCEyy	EJUCFyy	EJUCGyy	EJUCHyy	EJUCIyy	EJUCJyy	EJUCKyy	EJUCLyy
PJM Duquesne Pk	Market	EJUAB00	EJUAAyy	EJUAByy	EJUACyy	EJUADyy	EJUAEyy	EJUAFyy	EJUAGyy	EJUAHyy	EJUAIyy	EJUAJyy	EJUAKyy	EJUALyy
PJM Eastern Hub Opk	Market	EPEOB00	EPEOAyy	EPEOByy	EPEOCyy	EPEODyy	EPEOEyy	EPEOFyy	EPEOGyy	EPEOHyy	EPEOIyy	EPEOJyy	EPEOKyy	EPEOLyy
PJM Eastern Hub Pk	Market	EPEMB00	EPEMAyy	EPEMByy	EPEMCyy	EPEMDyy	EPEMEyy	EPEMFyy	EPEMGyy	EPEMHyy	EPEMIyy	EPEMJyy	EPEMKyy	EPEMLyy
PJM FE Ohio Opk	Market	EJHOB00	EJHOAyy	EJHOByy	EJHOCyy	EJHODyy	EJHOEyy	EJHOFyy	EJHOGyy	EJHOHyy	EJHOIyy	EJHOJyy	EJHOKyy	EJHOLyy

M2MS-POWER PJM/MISO REGION SYMBOLS FOR 10 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
PJM FE Ohio Pk	Market	EJHMB00	EJHMAyy	EJHMByy	EJHMCyy	EJHMDyy	EJHMEyy	EJHMFyy	EJHMGyy	EJHMHyy	EJHMIyy	EJHMJyy	EJHMKyy	EJHMLyy
PJM JPCL Zone Opk	Market	EJCOB00	EJCOAyy	EJCOByy	EJCOCyy	EJCODyy	EJCOEyy	EJCOFyy	EJCOGyy	EJCOHyy	EJCOIyy	EJCOJyy	EJCOKyy	EJCOLyy
PJM JPCL Zone Pk	Market	EJCMB00	EJCMAyy	EJCMByy	EJCMCyy	EJCMDyy	EJCMEyy	EJCMFyy	EJCMGyy	EJCMHyy	EJCMIyy	EJCMJyy	EJCMKyy	EJCMLyy
PJM METED Opk	Market	EJMCB00	EJMCAyy	EJMCByy	EJMCCyy	EJMCDyy	EJMCEyy	EJMCFyy	EJMCGyy	EJMCHyy	EJMCIyy	EJMCJyy	EJMCKyy	EJMCLyy
PJM METED Pk	Market	EJMAB00	EJMAAyy	EJMAByy	EJMACyy	EJMADyy	EJMAEyy	EJMAFyy	EJMAGyy	EJMAHyy	EJMAIyy	EJMAJyy	EJMAKyy	EJMALyy
PJM NI Hub Opk	Market	ECEOB00	ECEOAyy	ECEOByy	ECEOCyy	ECEODyy	ECEOEyy	ECEOFyy	ECEOGyy	ECEOHyy	ECEOIyy	ECEOJyy	ECEOKyy	ECEOLyy
PJM NI Hub Pk	Market	ECEMB00	ECEMAyy	ECEMByy	ECEMCyy	ECEMDyy	ECEMEyy	ECEMFyy	ECEMGyy	ECEMHyy	ECEMIyy	ECEMJyy	ECEMKyy	ECEMLyy
PJM PECO Zone Opk	Market	EPCOB00	EPCOAyy	EPCOByy	EPCOCyy	EPCODyy	EPCOEyy	EPCOFyy	EPCOGyy	EPCOHyy	EPCOIyy	EPCOJyy	EPCOKyy	EPCOLyy
PJM PECO Zone Pk	Market	EPCMB00	EPCMAyy	EPCMByy	EPCMCyy	EPCMDyy	EPCMEyy	EPCMFyy	EPCMGyy	EPCMHyy	EPCMIyy	EPCMJyy	EPCMKyy	EPCMLyy
PJM PENELEC Opk	Market	EJNCB00	EJNCAyy	EJNCByy	EJNCCyy	EJNCDyy	EJNCEyy	EJNCFyy	EJNCGyy	EJNCHyy	EJNCIyy	EJNCJyy	EJNCKyy	EJNCLyy
PJM PENELEC Pk	Market	EJNAB00	EJNAAyy	EJNAByy	EJNACyy	EJNADyy	EJNAEyy	EJNAFyy	EJNAGyy	EJNAHyy	EJNAIyy	EJNAJyy	EJNAKyy	EJNALyy
PJM PEPCO Zone Opk	Market	EPPOB00	EPPOAyy	EPPOByy	EPPOCyy	EPPODyy	EPPOEyy	EPPOFyy	EPPOGyy	EPPOHyy	EPPOIyy	EPPOJyy	EPPOKyy	EPPOLyy
PJM PEPCO Zone Pk	Market	EPPMB00	EPPMAyy	EPPMByy	EPPMCyy	EPPMDyy	EPPMEyy	EPPMFyy	EPPMGyy	EPPMHyy	EPPMIyy	EPPMJyy	EPPMKyy	EPPMLyy
PJM PPL Zone Opk	Market	EPLOB00	EPLOAyy	EPLOByy	EPLOCyy	EPLODyy	EPLOEyy	EPLOFyy	EPLOGyy	EPLOHyy	EPLOIyy	EPLOJyy	EPLOKyy	EPLOLyy
PJM PPL Zone Pk	Market	EPLMB00	EPLMAyy	EPLMByy	EPLMCyy	EPLMDyy	EPLMEyy	EPLMFyy	EPLMGyy	EPLMHyy	EPLMIyy	EPLMJyy	EPLMKyy	EPLMLyy
PJM PSEG Zone Opk	Market	ESGOB00	ESGOAyy	ESGOByy	ESGOCyy	ESGODyy	ESGOEyy	ESGOFyy	ESGOGyy	ESGOHyy	ESGOIyy	ESGOJyy	ESGOKyy	ESGOLyy
PJM PSEG Zone Pk	Market	ESGMB00	ESGMAyy	ESGMByy	ESGMCyy	ESGMDyy	ESGMEyy	ESGMFyy	ESGMGyy	ESGMHyy	ESGMIyy	ESGMJyy	ESGMKyy	ESGMLyy
PJM Rockland Electric Zone Opk	Proxy	EJROB00	EJROAyy	EJROByy	EJROCyy	EJRODyy	EJROEyy	EJROFyy	EJROGyy	EJROHyy	EJROIyy	EJROJyy	EJROKyy	EJROLyy
PJM Rockland Electric Zone Pk	Proxy	EJRMB00	EJRMAyy	EJRMByy	EJRMCyy	EJRMDyy	EJRMEyy	EJRMFyy	EJRMGyy	EJRMHyy	EJRMIyy	EJRMJyy	EJRMKyy	EJRMLyy
PJM Western Hub Opk	Market	EPJOB00	EPJOAyy	EPJOByy	EPJOCyy	EPJODyy	EPJOEyy	EPJOFyy	EPJOGyy	EPJOHyy	EPJOIyy	EPJOJyy	EPJOKyy	EPJOLyy
PJM Western Hub Pk	Market	EPJMB00	EPJMAyy	EPJMByy	EPJMCyy	EPJMDyy	EPJMEyy	EPJMFyy	EPJMGyy	EPJMHyy	EPJMIyy	EPJMJyy	EPJMKyy	EPJMLyy

* The symbols in this table are displayed in summation notation. For example, to derive the symbol for ISO-NE NE-Mass Hub Pk January 2017, replace the yy inENMBAyy from the table above with 17 to make ENMBA17.

M2MS-POWER PJM/MISO REGION SYMBOLS FOR 20 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
PJM AD Hub Opk	Market	EECQB00	EECQAyy	EECQByy	EECQCyy	EECQDyy	EECQEyy	EECQFyy	EECQGyy	EECQHyy	EECQIyy	EECQJyy	EECQKyy	EECQLyy
PJM AD Hub Pk	Market	EECPB00	EECPAyy	EECPByy	EECPCyy	EECPDyy	EECPEyy	EECPFyy	EECPGyy	EECPHyy	EECPIyy	EECPJyy	EECPKyy	EECPLyy
MISO Indiana Opk	Market	ECIQB00	ECIQAyy	ECIQByy	ECIQCyy	ECIQDyy	ECIQEyy	ECIQFyy	ECIQGyy	ECIQHyy	ECIQIyy	ECIQJyy	ECIQKyy	ECIQLyy
MISO Indiana Pk	Market	ECIPB00	ECIPAyy	ECIPByy	ECIPCyy	ECIPDyy	ECIPEyy	ECIPFyy	ECIPGyy	ECIPHyy	ECIPIyy	ECIPJyy	ECIPKyy	ECIPLyy
Michigan Opk	Market	EMIQB00	EMIQAyy	EMIQByy	EMIQCyy	EMIQDyy	EMIQEyy	EMIQFyy	EMIQGyy	EMIQHyy	EMIQIyy	EMIQJyy	EMIQKyy	EMIQLyy
Michigan Pk	Market	EMIPB00	EMIPAyy	EMIPByy	EMIPCyy	EMIPDyy	EMIPEyy	EMIPFyy	EMIPGyy	EMIPHyy	EMIPIyy	EMIPJyy	EMIPKyy	EMIPLyy
Minn Hub Opk	Market	EPMQB00	EPMQAyy	EPMQByy	EPMQCyy	EPMQDyy	EPMQEyy	EPMQFyy	EPMQGyy	EPMQHyy	EPMQIyy	EPMQJyy	EPMQKyy	EPMQLyy
Minn Hub Pk	Market	EPMPB00	EPMPAyy	EPMPByy	EPMPCyy	EPMPDyy	EPMPEyy	EPMPFyy	EPMPGyy	EPMPHyy	EPMPIyy	EPMPJyy	EPMPKyy	EPMPLyy
MISO Arkansas Hub Opk	Market	EMADB00	EMADAyy	EMADByy	EMADCyy	EMADDyy	EMADEyy	EMADFyy	EMADGyy	EMADHyy	EMADIyy	EMADJyy	EMADKyy	EMADLyy
MISO Arkansas Hub Pk	Market	EMABB00	EMABAyy	EMABByy	EMABCyy	EMABDyy	EMABEyy	EMABFyy	EMABGyy	EMABHyy	EMABIyy	EMABJyy	EMABKyy	EMABLyy

M2MS-POWER PJM/MISO REGION SYMBOLS FOR 20 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
MISO Illinois Hub Opk	Market	EILDB00	EILDAyy	EILDByy	EILDCyy	EILDDyy	EILDEyy	EILDFyy	EILDGyy	EILDHyy	EILDIyy	EILDJyy	EILDKyy	EILDLyy
MISO Illinois Hub Pk	Market	EILBB00	EILBAyy	EILBByy	EILBCyy	EILBDyy	EILBEyy	EILBFyy	EILBGyy	EILBHyy	EILBIyy	EILBJyy	EILBKyy	EILBLyy
MISO Louisiana Opk	Market	EMLDB00	EMLDAyy	EMLDByy	EMLDCyy	EMLDDyy	EMLDEyy	EMLDFyy	EMLDGyy	EMLDHyy	EMLDIyy	EMLDJyy	EMLDKyy	EMLDLyy
MISO Louisiana Pk	Market	EMLBB00	EMLBAyy	EMLBByy	EMLBCyy	EMLBDyy	EMLBEyy	EMLBFyy	EMLBGyy	EMLBHyy	EMLBIyy	EMLBJyy	EMLBKyy	EMLBLyy
MISO Texas Hub Opk	Market	EMEDB00	EMEDAyy	EMEDByy	EMEDCyy	EMEDDyy	EMEDEyy	EMEDFyy	EMEDGyy	EMEDHyy	EMEDIyy	EMEDJyy	EMEDKyy	EMEDLyy
MISO Texas Hub Pk	Market	EMEBB00	EMEBAyy	EMEBByy	EMEBCyy	EMEBDyy	EMEBEyy	EMEBFyy	EMEBGyy	EMEBHyy	EMEBIyy	EMEBJyy	EMEBKyy	EMEBLyy
PJM NI Hub Opk	Market	ECEQB00	ECEQAyy	ECEQByy	ECEQCyy	ECEQDyy	ECEQEyy	ECEQFyy	ECEQGyy	ECEQHyy	ECEQIyy	ECEQJyy	ECEQKyy	ECEQLyy
PJM NI Hub Pk	Market	ECEPB00	ECEPAyy	ECEPByy	ECEPCyy	ECEPDyy	ECEPEyy	ECEPFyy	ECEPGyy	ECEPHyy	ECEPIyy	ECEPJyy	ECEPKyy	ECEPLyy
PJM AECO Opk	Market	EJADB00	EJADAyy	EJADByy	EJADCyy	EJADDyy	EJADEyy	EJADFyy	EJADGyy	EJADHyy	EJADIyy	EJADJyy	EJADKyy	EJADLyy
PJM AECO Pk	Market	EJABB00	EJABAyy	EJABByy	EJABCyy	EJABDyy	EJABEyy	EJABFyy	EJABGyy	EJABHyy	EJABIyy	EJABJyy	EJABKyy	EJABLyy
PJM AEP Opk	Market	EJEQB00	EJEQAyy	EJEQByy	EJEQCyy	EJEQDyy	EJEQEyy	EJEQFyy	EJEQGyy	EJEQHyy	EJEQIyy	EJEQJyy	EJEQKyy	EJEQLyy
PJM AEP Pk	Market	EJEPB00	EJEPAyy	EJEPByy	EJEPCyy	EJEPDyy	EJEPEyy	EJEPFyy	EJEPGyy	EJEPHyy	EJEPIyy	EJEPJyy	EJEPKyy	EJEPLyy
PJM APS Opk	Market	EJSDB00	EJSDAyy	EJSDByy	EJSDCyy	EJSDDyy	EJSDEyy	EJSDFyy	EJSDGyy	EJSDHyy	EJSDIyy	EJSDJyy	EJSDKyy	EJSDLyy
PJM APS Pk	Market	EJSBB00	EJSBAyy	EJSBByy	EJSBCyy	EJSBDyy	EJSBEyy	EJSBFyy	EJSBGyy	EJSBHyy	EJSBIyy	EJSBJyy	EJSBKyy	EJSBLyy
PJM ATSI Opk	Market	EJTQB00	EJTQAyy	EJTQByy	EJTQCyy	EJTQDyy	EJTQEyy	EJTQFyy	EJTQGyy	EJTQHyy	EJTQIyy	EJTQJyy	EJTQKyy	EJTQLyy
PJM ATSI Pk	Market	EJTPB00	EJTPAyy	EJTPByy	EJTPCyy	EJTPDyy	EJTPEyy	EJTPFyy	EJTPGyy	EJTPHyy	EJTPIyy	EJTPJyy	EJTPKyy	EJTPLyy
PJM BGE Zone Opk	Market	EBGQB00	EBGQAyy	EBGQByy	EBGQCyy	EBGQDyy	EBGQEyy	EBGQFyy	EBGQGyy	EBGQHyy	EBGQIyy	EBGQJyy	EBGQKyy	EBGQLyy
PJM BGE Zone Pk	Market	EBGPB00	EBGPAyy	EBGPByy	EBGPCyy	EBGPDyy	EBGPEyy	EBGPFyy	EBGPGyy	EBGPHyy	EBGPIyy	EBGPJyy	EBGPKyy	EBGPLyy
PJM ComEd Opk	Market	EJODB00	EJODAyy	EJODByy	EJODCyy	EJODDyy	EJODEyy	EJODFyy	EJODGyy	EJODHyy	EJODIyy	EJODJyy	EJODKyy	EJODLyy
PJM ComEd Pk	Market	EJOBB00	EJOBAyy	EJOBByy	EJOBCyy	EJOBDyy	EJOBEyy	EJOBFyy	EJOBGyy	EJOBHyy	EJOBIyy	EJOBJyy	EJOBKyy	EJOBLyy
PJM DEOK Opk	Market	EJKQB00	EJKQAyy	EJKQByy	EJKQCyy	EJKQDyy	EJKQEyy	EJKQFyy	EJKQGyy	EJKQHyy	EJKQIyy	EJKQJyy	EJKQKyy	EJKQLyy
PJM DEOK Pk	Market	EJKPB00	EJKPAyy	EJKPByy	EJKPCyy	EJKPDyy	EJKPEyy	EJKPFyy	EJKPGyy	EJKPHyy	EJKPIyy	EJKPJyy	EJKPKyy	EJKPLyy
PJM DPL Opk	Market	EJDDB00	EJDDAyy	EJDDByy	EJDDCyy	EJDDDyy	EJDDEyy	EJDDFyy	EJDDGyy	EJDDHyy	EJDDIyy	EJDDJyy	EJDDKyy	EJDDLyy
PJM DPL Pk	Market	EJDBB00	EJDBAyy	EJDBByy	EJDBCyy	EJDBDyy	EJDBEyy	EJDBFyy	EJDBGyy	EJDBHyy	EJDBIyy	EJDBJyy	EJDBKyy	EJDBLyy
PJM Duquesne Opk	Market	EJUDB00	EJUDAyy	EJUDByy	EJUDCyy	EJUDDyy	EJUDEyy	EJUDFyy	EJUDGyy	EJUDHyy	EJUDIyy	EJUDJyy	EJUDKyy	EJUDLyy
PJM Duquesne Pk	Market	EJUBB00	EJUBAyy	EJUBByy	EJUBCyy	EJUBDyy	EJUBEyy	EJUBFyy	EJUBGyy	EJUBHyy	EJUBIyy	EJUBJyy	EJUBKyy	EJUBLyy
PJM Eastern Hub Opk	Market	EPEQB00	EPEQAyy	EPEQByy	EPEQCyy	EPEQDyy	EPEQEyy	EPEQFyy	EPEQGyy	EPEQHyy	EPEQIyy	EPEQJyy	EPEQKyy	EPEQLyy
PJM Eastern Hub Pk	Market	EPEPB00	EPEPAyy	EPEPByy	EPEPCyy	EPEPDyy	EPEPEyy	EPEPFyy	EPEPGyy	EPEPHyy	EPEPIyy	EPEPJyy	EPEPKyy	EPEPLyy
PJM FE Ohio Opk	Market	EJHQB00	EJHQAyy	EJHQByy	EJHQCyy	EJHQDyy	EJHQEyy	EJHQFyy	EJHQGyy	EJHQHyy	EJHQIyy	EJHQJyy	EJHQKyy	EJHQLyy
PJM FE Ohio Pk	Market	EJHPB00	EJHPAyy	EJHPByy	EJHPCyy	EJHPDyy	EJHPEyy	EJHPFyy	EJHPGyy	EJHPHyy	EJHPIyy	EJHPJyy	EJHPKyy	EJHPLyy
PJM JPCL Zone Opk	Market	EJCQB00	EJCQAyy	EJCQByy	EJCQCyy	EJCQDyy	EJCQEyy	EJCQFyy	EJCQGyy	EJCQHyy	EJCQIyy	EJCQJyy	EJCQKyy	EJCQLyy
PJM JPCL Zone Pk	Market	EJCPB00	EJCPAyy	EJCPByy	EJCPCyy	EJCPDyy	EJCPEyy	EJCPFyy	EJCPGyy	EJCPHyy	EJCPIyy	EJCPJyy	EJCPKyy	EJCPLyy
PJM METED Opk	Market	EJMDB00	EJMDAyy	EJMDByy	EJMDCyy	EJMDDyy	EJMDEyy	EJMDFyy	EJMDGyy	EJMDHyy	EJMDIyy	EJMDJyy	EJMDKyy	EJMDLyy
PJM METED Pk	Market	EJMBB00	EJMBAyy	EJMBByy	EJMBCyy	EJMBDyy	EJMBEyy	EJMBFyy	EJMBGyy	EJMBHyy	EJMBIyy	EJMBJyy	EJMBKyy	EJMBLyy
PJM PECO Zone Opk	Market	EPCQB00	EPCQAyy	EPCQByy	EPCQCyy	EPCQDyy	EPCQEyy	EPCQFyy	EPCQGyy	EPCQHyy	EPCQIyy	EPCQJyy	EPCQKyy	EPCQLyy
PJM PECO Zone Pk	Market	EPCPB00	EPCPAyy	EPCPByy	EPCPCyy	EPCPDyy	EPCPEyy	EPCPFyy	EPCPGyy	EPCPHyy	EPCPIyy	EPCPJyy	EPCPKyy	EPCPLyy
PJM PENELEC Opk	Market	EJNDB00	EJNDAyy	EJNDByy	EJNDCyy	EJNDDyy	EJNDEyy	EJNDFyy	EJNDGyy	EJNDHyy	EJNDIyy	EJNDJyy	EJNDKyy	EJNDLyy

M2MS-POWER PJM/MISO REGION SYMBOLS FOR 20 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
PJM PENELEC Pk	Market	EJNBB00	EJNBAyy	EJNBByy	EJNBCyy	EJNBDyy	EJNBEyy	EJNBFyy	EJNBGyy	EJNBHyy	EJNBIyy	EJNBJyy	EJNBKyy	EJNBLyy
PJM PEPCO Zone Opk	Market	EPPQB00	EPPQAyy	EPPQByy	EPPQCyy	EPPQDyy	EPPQEyy	EPPQFyy	EPPQGyy	EPPQHyy	EPPQIyy	EPPQJyy	EPPQKyy	EPPQLyy
PJM PEPCO Zone Pk	Market	EPPPB00	EPPPAyy	EPPPByy	EPPPCyy	EPPPDyy	EPPPEyy	EPPPFyy	EPPPGyy	EPPPHyy	EPPPIyy	EPPPJyy	EPPPKyy	EPPPLyy
PJM PPL Zone Opk	Market	EPLQB00	EPLQAyy	EPLQByy	EPLQCyy	EPLQDyy	EPLQEyy	EPLQFyy	EPLQGyy	EPLQHyy	EPLQIyy	EPLQJyy	EPLQKyy	EPLQLyy
PJM PPL Zone Pk	Market	EPLPB00	EPLPAyy	EPLPByy	EPLPCyy	EPLPDyy	EPLPEyy	EPLPFyy	EPLPGyy	EPLPHyy	EPLPIyy	EPLPJyy	EPLPKyy	EPLPLyy
PJM PSEG Zone Opk	Market	ESGQB00	ESGQAyy	ESGQByy	ESGQCyy	ESGQDyy	ESGQEyy	ESGQFyy	ESGQGyy	ESGQHyy	ESGQIyy	ESGQJyy	ESGQKyy	ESGQLyy
PJM PSEG Zone Pk	Market	ESGPB00	ESGPAyy	ESGPByy	ESGPCyy	ESGPDyy	ESGPEyy	ESGPFyy	ESGPGyy	ESGPHyy	ESGPIyy	ESGPJyy	ESGPKyy	ESGPLyy
PJM Rockland Electric Zone Opk	Proxy	EJRQB00	EJRQAyy	EJRQByy	EJRQCyy	EJRQDyy	EJRQEyy	EJRQFyy	EJRQGyy	EJRQHyy	EJRQIyy	EJRQJyy	EJRQKyy	EJRQLyy
PJM Rockland Electric Zone Pk	Proxy	EJRPB00	EJRPAyy	EJRPByy	EJRPCyy	EJRPDyy	EJRPEyy	EJRPFyy	EJRPGyy	EJRPHyy	EJRPIyy	EJRPJyy	EJRPKyy	EJRPLyy
PJM Western Hub Opk	Market	EPJQB00	EPJQAyy	EPJQByy	EPJQCyy	EPJQDyy	EPJQEyy	EPJQFyy	EPJQGyy	EPJQHyy	EPJQIyy	EPJQJyy	EPJQKyy	EPJQLyy
PJM Western Hub Pk	Market	EPJPB00	EPJPAyy	EPJPByy	EPJPCyy	EPJPDyy	EPJPEyy	EPJPFyy	EPJPGyy	EPJPHyy	EPJPIyy	EPJPJyy	EPJPKyy	EPJPLyy

* The symbols in this table are displayed in summation notation. For example, to derive the symbol for ISO-NE NE-Mass Hub Pk January 2017, replace the yy inENMBAyy from the table above with 17 to make ENMBA17.

PJM/MISO

Michigan
MISO Michigan Hub is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by Midwest ISO on their website www.misoenergy.com.

MISO Arkansas Hub
MISO Arkansas Hub is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by Midwest ISO on their website www.misoenergy.com.

MISO Illinois Hub
MISO Illinois Hub is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by Midwest ISO on their website www.misoenergy.com.

MISO Indiana Hub
MISO Indiana Hub is based on the on peak and off peak mathematical averages of the hourly real time LMP prices published by Midwest ISO on their website www.misoenergy.com.

MISO Louisiana Hub
MISO Louisiana Hub is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by Midwest ISO on their website www.misoenergy.com.

MISO Minn Hub
MISO Minn Hub is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by Midwest ISO on their website www.misoenergy.com.

MISO Texas Hub
MISO Texas Hub is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by Midwest ISO on their website www.misoenergy.com.

PJM Rockland Electric Zone
Includes Rockland Electric Company's Eastern Division in Bergen County, NJ. Rockland's Eastern Division serves about 400 megawatts of load. It does not include any generating capacity. The division is directly interconnected with facilities controlled by PJM through a 345-kilovolt transmission line. www.pjm.com

PJM AD Hub
PJM AD Hub is based on the on peak and off peak mathematical averages of the hourly real time LMP prices published by PJM on their website www.pjm.com.

PJM AECO
PJM AECO is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM AEP
PJM AEP is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM APS
PJM APS is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM ATSI
PJM ATSI is based on the on peak and off peak mathematical

averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM BGE Zone
PJM BGE Zone is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM ComEd
PJM ComEd is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM DEOK
PJM DEOK is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM DPL
PJM DPL is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM Duquesne
PJM Duquesne is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM Eastern Hub
PJM Eastern Hub is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM FE Ohio
PJM FE Ohio is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM JCPL Zone
PJM JCPL Zone is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM METED
PJM METED is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM NI Hub
PJM NI Hub is based on the on peak and off peak mathematical averages of the hourly real time LMP prices published by PJM on their website www.pjm.com.

PJM PECO Zone
PJM PECO Zone is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM PENELEC
PJM PENELEC is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM PEPCO Zone
PJM PEPCO Zone is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM PPL Zone
PJM PPL Zone is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM PSEG Zone
PJM PSEG Zone is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by PJM on their website www.pjm.com.

PJM Western Hub
PJM Western Hub is based on the on peak and off peak mathematical averages of the hourly real time LMP prices published by PJM on their website www.pjm.com.

M2MS-POWER SOUTHEAST REGION SYMBOLS FOR 10 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
Florida Opk	Proxy	EFLOB00	EFLOAyy	EFLOByy	EFLOCyy	EFLODyy	EFLOEyy	EFLOFyy	EFLOGyy	EFLOHyy	EFLOIyy	EFLOJyy	EFLOKyy	EFLOLyy
Florida Pk	Proxy	EFLMB00	EFLMAyy	EFLMByy	EFLMCyy	EFLMDyy	EFLMEyy	EFLMFyy	EFLMGyy	EFLMHyy	EFLMIyy	EFLMJyy	EFLMKyy	EFLMLyy
Into TVA Opk	Proxy	ETVCB00	ETVCAyy	ETVCByy	ETVCCyy	ETVCDyy	ETVCEyy	ETVCFyy	ETVCGyy	ETVCHyy	ETVCIyy	ETVCJyy	ETVCKyy	ETVCLyy
Into TVA Pk	Proxy	ETVAB00	ETVAAyy	ETVAByy	ETVACyy	ETVADyy	ETVAEyy	ETVAFyy	ETVAGyy	ETVAHyy	ETVAIyy	ETVAJyy	ETVAKyy	ETVALyy
Into Southern Opk	Proxy	ESTOB00	ESTOAyy	ESTOByy	ESTOCyy	ESTODyy	ESTOEyy	ESTOFyy	ESTOGyy	ESTOHyy	ESTOIyy	ESTOJyy	ESTOKyy	ESTOLyy
Into Southern Pk	Proxy	ESTMB00	ESTMAyy	ESTMByy	ESTMCyy	ESTMDyy	ESTMEyy	ESTMFyy	ESTMGyy	ESTMHyy	ESTMIyy	ESTMJyy	ESTMKyy	ESTMLyy
Vacar Opk	Proxy	ESVOB00	ESVOAyy	ESVOByy	ESVOCyy	ESVODyy	ESVOEyy	ESVOFyy	ESVOGyy	ESVOHyy	ESVOIyy	ESVOJyy	ESVOKyy	ESVOLyy
Vacar Pk	Proxy	ESVMB00	ESVMAyy	ESVMByy	ESVMCyy	ESVMDyy	ESVMEyy	ESVMFyy	ESVMGyy	ESVMHyy	ESVMIyy	ESVMJyy	ESVMKyy	ESVMLyy
SPP North Opk	Market	ESNOB00	ESNOAyy	ESNOByy	ESNOCyy	ESNODyy	ESNOEyy	ESNOFyy	ESNOGyy	ESNOHyy	ESNOIyy	ESNOJyy	ESNOKyy	ESNOLyy
SPP North Pk	Market	ESNMB00	ESNMAyy	ESNMByy	ESNMCyy	ESNMDyy	ESNMEyy	ESNMFyy	ESNMGyy	ESNMHyy	ESNMIyy	ESNMJyy	ESNMKyy	ESNMLyy
SPP South Opk	Market	ESWOB00	ESWOAyy	ESWOByy	ESWOCyy	ESWODyy	ESWOEyy	ESWOFyy	ESWOGyy	ESWOHyy	ESWOIyy	ESWOJyy	ESWOKyy	ESWOLyy
SPP South Pk	Market	ESWMB00	ESWMAyy	ESWMByy	ESWMCyy	ESWMDyy	ESWMEyy	ESWMFyy	ESWMGyy	ESWMHyy	ESWMIyy	ESWMJyy	ESWMKyy	ESWMLyy

* The symbols in this table are displayed in summation notation. For example, to derive the symbol for ISO-NE NE-Mass Hub Pk January 2017, replace the yy inENMBAyy from the table above with 17 to make ENMBA17.

M2MS-POWER SOUTHEAST REGION SYMBOLS FOR 20 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
Florida Opk	Proxy	EFLQB00	EFLQAyy	EFLQByy	EFLQCyy	EFLQDyy	EFLQEyy	EFLQFyy	EFLQGyy	EFLQHyy	EFLQIyy	EFLQJyy	EFLQKyy	EFLQLyy
Florida Pk	Proxy	EFLPB00	EFLPAyy	EFLPByy	EFLPCyy	EFLPDyy	EFLPEyy	EFLPFyy	EFLPGyy	EFLPHyy	EFLPIyy	EFLPJyy	EFLPKyy	EFLPLyy
Into TVA Opk	Proxy	ETVDB00	ETVDAyy	ETVDByy	ETVDCyy	ETVDDyy	ETVDEyy	ETVDFyy	ETVDGyy	ETVDHyy	ETVDIyy	ETVDJyy	ETVDKyy	ETVDLyy
Into TVA Pk	Proxy	ETVBB00	ETVBAyy	ETVBByy	ETVBCyy	ETVBDyy	ETVBEyy	ETVBFyy	ETVBGyy	ETVBHyy	ETVBIyy	ETVBJyy	ETVBKyy	ETVBLyy
Into Southern Opk	Proxy	ESTQB00	ESTQAyy	ESTQByy	ESTQCyy	ESTQDyy	ESTQEyy	ESTQFyy	ESTQGyy	ESTQHyy	ESTQIyy	ESTQJyy	ESTQKyy	ESTQLyy
Into Southern Pk	Proxy	ESTPB00	ESTPAyy	ESTPByy	ESTPCyy	ESTPDyy	ESTPEyy	ESTPFyy	ESTPGyy	ESTPHyy	ESTPIyy	ESTPJyy	ESTPKyy	ESTPLyy
Vacar Opk	Proxy	ESVQB00	ESVQAyy	ESVQByy	ESVQCyy	ESVQDyy	ESVQEyy	ESVQFyy	ESVQGyy	ESVQHyy	ESVQIyy	ESVQJyy	ESVQKyy	ESVQLyy
Vacar Pk	Proxy	ESVPB00	ESVPAyy	ESVPByy	ESVPCyy	ESVPDyy	ESVPEyy	ESVPFyy	ESVPGyy	ESVPHyy	ESVPIyy	ESVPJyy	ESVPKyy	ESVPLyy
SPP North Opk	Market	ESNQB00	ESNQAyy	ESNQByy	ESNQCyy	ESNQDyy	ESNQEyy	ESNQFyy	ESNQGyy	ESNQHyy	ESNQIyy	ESNQJyy	ESNQKyy	ESNQLyy
SPP North Pk	Market	ESNPB00	ESNPAyy	ESNPByy	ESNPCyy	ESNPDyy	ESNPEyy	ESNPFyy	ESNPGyy	ESNPHyy	ESNPIyy	ESNPJyy	ESNPKyy	ESNPLyy
SPP South Opk	Market	ESWQB00	ESWQAyy	ESWQByy	ESWQCyy	ESWQDyy	ESWQEyy	ESWQFyy	ESWQGyy	ESWQHyy	ESWQIyy	ESWQJyy	ESWQKyy	ESWQLyy
SPP South Pk	Market	ESWPB00	ESWPAyy	ESWPByy	ESWPCyy	ESWPDyy	ESWPEyy	ESWPFyy	ESWPGyy	ESWPHyy	ESWPIyy	ESWPJyy	ESWPKyy	ESWPLyy

* The symbols in this table are displayed in summation notation. For example, to derive the symbol for ISO-NE NE-Mass Hub Pk January 2017, replace the yy inENMBAyy from the table above with 17 to make ENMBA17.

SOUTHEAST REGION

Florida
The Florida instate pricing area comprises control areas within the State of Florida or the Florida Reliability Coordination Council (FRPCC), excluding Gulf Power, which is part of the Southern Company control area. Florida control areas include: Progress Energy Florida, Florida Power & Light Company, Tampa Electric Company, Florida Municipal Power Agency, Gainesville Regional Utilities, JEA, City of Lakeland, Orlando Utilities Commission, City of Tallahassee and Seminole Electric Cooperative.

Into Southern
Into Southern comprises power delivered to an interface with or a delivery point within the Southern Company control area, which spans a swath of SERC from Georgia to Mississippi including a portion of the Florida pan handle. (Control area for purposes of this location description is defined to exclude any other entity's transmission system for which the utility acts as the balancing authority.)

Into TVA
Into TVA comprises power delivered to an interface with or a delivery point within the control area of the Tennessee Valley Authority, which includes Tennessee and the northern portion of Alabama. (Control area for the purposes of this location description is defined to exclude any other entity's system for which TVA acts as the balancing authority.)

SPP North
SPP North is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by SPP on their website www.spp.org.

SPP South
SPP South is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by SPP on their website www.spp.org.

VACAR
VACAR comprises the control areas in the Virginia and Carolinas subregion of the Southeastern Electric Reliability Council, including: Progress Energy's Carolina Power and Light east and west, Duke(?), South Carolina Electric and Gas, Santee Cooper, Southeastern Power Administration and APGI Yadkin Division. Dominion's Virginia Power control area has been excluded since it joined the PJM interconnection on May 1, 2005.

M2MS-POWER ERCOT REGION SYMBOLS FOR 10 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
ERCOT Houston Hub Opk	Market	ETSOB00	ETSOAyy	ETSOByy	ETSOCyy	ETSODyy	ETSOEyy	ETSOFyy	ETSOGyy	ETSOHyy	ETSOIyy	ETSOJyy	ETSOKyy	ETSOLyy
ERCOT Houston Hub Pk	Market	ETSMB00	ETSMAyy	ETSMByy	ETSMCyy	ETSMDyy	ETSMEyy	ETSMFyy	ETSMGyy	ETSMHyy	ETSMIyy	ETSMJyy	ETSMKyy	ETSMLyy
ERCOT North Hub Opk	Market	ETNOB00	ETNOAyy	ETNOByy	ETNOCyy	ETNODyy	ETNOEyy	ETNOFyy	ETNOGyy	ETNOHyy	ETNOIyy	ETNOJyy	ETNOKyy	ETNOLyy
ERCOT North Hub Pk	Market	ETNMB00	ETNMAyy	ETNMByy	ETNMCyy	ETNMDyy	ETNMEyy	ETNMFyy	ETNMGyy	ETNMHyy	ETNMIyy	ETNMJyy	ETNMKyy	ETNMLyy
ERCOT South Hub Opk	Market	ETHOB00	ETHOAyy	ETHOByy	ETHOCyy	ETHODyy	ETHOEyy	ETHOFyy	ETHOGyy	ETHOHyy	ETHOIyy	ETHOJyy	ETHOKyy	ETHOLyy
ERCOT South Hub Pk	Market	ETHMB00	ETHMAyy	ETHMByy	ETHMCyy	ETHMDyy	ETHMEyy	ETHMFyy	ETHMGyy	ETHMHyy	ETHMIyy	ETHMJyy	ETHMKyy	ETHMLyy
ERCOT West Hub Opk	Market	ETWOB00	ETWOAyy	ETWOByy	ETWOCyy	ETWODyy	ETWOEyy	ETWOFyy	ETWOGyy	ETWOHyy	ETWOIyy	ETWOJyy	ETWOKyy	ETWOLyy
ERCOT West Hub Pk	Market	ETWMB00	ETWMAyy	ETWMByy	ETWMCyy	ETWMDyy	ETWMEyy	ETWMFyy	ETWMGyy	ETWMHyy	ETWMIyy	ETWMJyy	ETWMKyy	ETWMLyy

* The symbols in this table are displayed in summation notation. For example, to derive the symbol for ISO-NE NE-Mass Hub Pk January 2017, replace the yy inENMBAyy from the table above with 17 to make ENMBA17.

M2MS-POWER ERCOT REGION SYMBOLS FOR 20 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
ERCOT Houston Hub Opk	Market	ETSQB00	ETSQAyy	ETSQByy	ETSQCyy	ETSQDyy	ETSQEyy	ETSQFyy	ETSQGyy	ETSQHyy	ETSQIyy	ETSQJyy	ETSQKyy	ETSQLyy
ERCOT Houston Hub Pk	Market	ETSPB00	ETSPAyy	ETSPByy	ETSPCyy	ETSPDyy	ETSPEyy	ETSPFyy	ETSPGyy	ETSPHyy	ETSPIyy	ETSPJyy	ETSPKyy	ETSPLyy
ERCOT North Hub Opk	Market	ETNQB00	ETNQAyy	ETNQByy	ETNQCyy	ETNQDyy	ETNQEyy	ETNQFyy	ETNQGyy	ETNQHyy	ETNQIyy	ETNQJyy	ETNQKyy	ETNQLyy
ERCOT North Hub Pk	Market	ETNPB00	ETNPAyy	ETNPByy	ETNPCyy	ETNPDyy	ETNPEyy	ETNPFyy	ETNPGyy	ETNPHyy	ETNPIyy	ETNPJyy	ETNPKyy	ETNPLyy
ERCOT South Hub Opk	Market	ETHQB00	ETHQAyy	ETHQByy	ETHQCyy	ETHQDyy	ETHQEyy	ETHQFyy	ETHQGyy	ETHQHyy	ETHQIyy	ETHQJyy	ETHQKyy	ETHQLyy
ERCOT South Hub Pk	Market	ETHPB00	ETHPAyy	ETHPByy	ETHPCyy	ETHPDyy	ETHPEyy	ETHPFyy	ETHPGyy	ETHPHyy	ETHPIyy	ETHPJyy	ETHPKyy	ETHPLyy
ERCOT West Hub Opk	Market	ETWQB00	ETWQAyy	ETWQByy	ETWQCyy	ETWQDyy	ETWQEyy	ETWQFyy	ETWQGyy	ETWQHyy	ETWQIyy	ETWQJyy	ETWQKyy	ETWQLyy
ERCOT West Hub Pk	Market	ETWPB00	ETWPAyy	ETWPByy	ETWPCyy	ETWPDyy	ETWPEyy	ETWPFyy	ETWPGyy	ETWPHyy	ETWPIyy	ETWPJyy	ETWPKyy	ETWPLyy

* The symbols in this table are displayed in summation notation. For example, to derive the symbol for ISO-NE NE-Mass Hub Pk January 2017, replace the yy inENMBAyy from the table above with 17 to make ENMBA17.

ERCOT REGION

ERCOT Houston Hub

ERCOT's Houston aggregate nodal trading hub, based on the on peak and off peak mathematical averages of the hourly real time LMP prices published by ERCOT on their website www.ercot.com.

ERCOT North Hub

ERCOT's North aggregate nodal trading hub, based on the on peak and off peak mathematical averages of the hourly real time LMP prices published by ERCOT on their website www.ercot.com.

ERCOT South Hub

ERCOT's South aggregate nodal trading hub, based on the on peak and off peak mathematical averages of the hourly real time LMP prices published by ERCOT on their website www.ercot.com.

ERCOT West Hub

ERCOT's West aggregate nodal trading hub, based on the on peak and off peak mathematical averages of the hourly real time LMP prices published by ERCOT on their website www.ercot.com.

M2MS-POWER WEST REGION SYMBOLS FOR 10 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
Alberta Opk	Market	EALOB00	EALOAyy	EALOByy	EALOCyy	EALODyy	EALOEyy	EALOFyy	EALOGyy	EALOHyy	EALOIyy	EALOJyy	EALOKyy	EALOLyy
Alberta Pk	Market	EALMB00	EALMAyy	EALMByy	EALMCyy	EALMDyy	EALMEyy	EALMFyy	EALMGyy	EALMHyy	EALMIyy	EALMJyy	EALMKyy	EALMLyy
Calif-Orecon Border Opk	Proxy	ECOOB00	ECOOAyy	ECOOByy	ECOOCyy	ECOODyy	ECOOEyy	ECOOFyy	ECOOGyy	ECOOHyy	ECOOIyy	ECOOJyy	ECOOKyy	ECOOLyy
Calif-Orecon Border Pk	Proxy	ECOMB00	ECOMAyy	ECOMByy	ECOMCyy	ECOMDyy	ECOMEyy	ECOMFyy	ECOMGyy	ECOMHyy	ECOMIyy	ECOMJyy	ECOMKyy	ECOMLyy
East Colorado Opk	Proxy	EWEOB00	EWEOAyy	EWEOByy	EWEOCyy	EWEODyy	EWEOEyy	EWEOFyy	EWEOGyy	EWEOHyy	EWEOIyy	EWEOJyy	EWEOKyy	EWEOLyy
East Colorado Pk	Proxy	EWEMB00	EWEMAyy	EWEMByy	EWEMCyy	EWEMDyy	EWEMEyy	EWEMFyy	EWEMGyy	EWEMHyy	EWEMIyy	EWEMJyy	EWEMKyy	EWEMLyy
Four Corners Opk	Proxy	EFCOB00	EFCOAyy	EFCOByy	EFCOCyy	EFCODyy	EFCOEyy	EFCOFyy	EFCOGyy	EFCOHyy	EFCOIyy	EFCOJyy	EFCOKyy	EFCOLyy
Four Corners Pk	Proxy	EFCMB00	EFCMAyy	EFCMByy	EFCMCyy	EFCMDyy	EFCMEyy	EFCMFyy	EFCMGyy	EFCMHyy	EFCMIyy	EFCMJyy	EFCMKyy	EFCMLyy
Mead Opk	Proxy	EMDOB00	EMDOAyy	EMDOByy	EMDOCyy	EMDODyy	EMDOEyy	EMDOFyy	EMDOGyy	EMDOHyy	EMDOIyy	EMDOJyy	EMDOKyy	EMDOLyy
Mead Pk	Proxy	EMDMB00	EMDMAyy	EMDMByy	EMDMCyy	EMDMDyy	EMDMEyy	EMDMFyy	EMDMGyy	EMDMHyy	EMDMIyy	EMDMJyy	EMDMKyy	EMDMLyy
Mid-Columbia Opk	Market	EMCOB00	EMCOAyy	EMCOByy	EMCOCyy	EMCODyy	EMCOEyy	EMCOFyy	EMCOGyy	EMCOHyy	EMCOIyy	EMCOJyy	EMCOKyy	EMCOLyy
Mid-Columbia Pk	Market	EMCMB00	EMCMAyy	EMCMByy	EMCMCyy	EMCMDyy	EMCMEyy	EMCMFyy	EMCMGyy	EMCMHyy	EMCMIyy	EMCMJyy	EMCMKyy	EMCMLyy
NOB, Nevada-Oregon Border Opk	Proxy	ENOOB00	ENOOAyy	ENOOByy	ENOOCyy	ENOODyy	ENOOEyy	ENOOFyy	ENOOGyy	ENOOHyy	ENOOIyy	ENOOJyy	ENOOKyy	ENOOLyy
NOB, Nevada-Oregon Border Pk	Proxy	ENOMB00	ENOMAyy	ENOMByy	ENOMCyy	ENOMDyy	ENOMEyy	ENOMFyy	ENOMGyy	ENOMHyy	ENOMIyy	ENOMJyy	ENOMKyy	ENOMLyy
North Path 15 Opk	Market	ENPOB00	ENPOAyy	ENPOByy	ENPOCyy	ENPODyy	ENPOEyy	ENPOFyy	ENPOGyy	ENPOHyy	ENPOIyy	ENPOJyy	ENPOKyy	ENPOLyy
North Path 15 Pk	Market	ENPMB00	ENPMAyy	ENPMByy	ENPMCyy	ENPMDyy	ENPMEyy	ENPMFyy	ENPMGyy	ENPMHyy	ENPMIyy	ENPMJyy	ENPMKyy	ENPMLyy
Palo Verde Opk	Market	EPVOB00	EPVOAyy	EPVOByy	EPVOCyy	EPVODyy	EPVOEyy	EPVOFyy	EPVOGyy	EPVOHyy	EPVOIyy	EPVOJyy	EPVOKyy	EPVOLyy
Palo Verde Pk	Market	EPVMB00	EPVMAyy	EPVMByy	EPVMCyy	EPVMDyy	EPVMEyy	EPVMFyy	EPVMGyy	EPVMHyy	EPVMIyy	EPVMJyy	EPVMKyy	EPVMLyy
Pinnacle Peak Opk	Proxy	EPNOB00	EPNOAyy	EPNOByy	EPNOCyy	EPNODyy	EPNOEyy	EPNOFyy	EPNOGyy	EPNOHyy	EPNOIyy	EPNOJyy	EPNOKyy	EPNOLyy
Pinnacle Peak Pk	Proxy	EPNMB00	EPNMAyy	EPNMByy	EPNMCyy	EPNMDyy	EPNMEyy	EPNMFyy	EPNMGyy	EPNMHyy	EPNMIyy	EPNMJyy	EPNMKyy	EPNMLyy
South Path 15 Opk	Market	ESPOB00	ESPOAyy	ESPOByy	ESPOCyy	ESPODyy	ESPOEyy	ESPOFyy	ESPOGyy	ESPOHyy	ESPOIyy	ESPOJyy	ESPOKyy	ESPOLyy
South Path 15 Pk	Market	ESPMB00	ESPMAyy	ESPMByy	ESPMCyy	ESPMDyy	ESPMEyy	ESPMFyy	ESPMGyy	ESPMHyy	ESPMIyy	ESPMJyy	ESPMKyy	ESPMLyy
Utah Opk	Proxy	EUTOB00	EUTOAyy	EUTOByy	EUTOCyy	EUTODyy	EUTOEyy	EUTOFyy	EUTOGyy	EUTOHyy	EUTOIyy	EUTOJyy	EUTOKyy	EUTOLyy
Utah Pk	Proxy	EUTMB00	EUTMAyy	EUTMByy	EUTMCyy	EUTMDyy	EUTMEyy	EUTMFyy	EUTMGyy	EUTMHyy	EUTMIyy	EUTMJyy	EUTMKyy	EUTMLyy

* The symbols in this table are displayed in summation notation. For example, to derive the symbol for ISO-NE NE-Mass Hub Pk January 2017, replace the yy inENMBAyy from the table above with 17 to make ENMBA17.

M2MS-POWER WEST REGION SYMBOLS FOR 20 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
Alberta Opk	Market	EALQB00	EALQAyy	EALQByy	EALQCyy	EALQDyy	EALQEyy	EALQFyy	EALQGyy	EALQHyy	EALQIyy	EALQJyy	EALQKyy	EALQLyy
Alberta Pk	Market	EALPB00	EALPAyy	EALPByy	EALPCyy	EALPDyy	EALPEyy	EALPFyy	EALPGyy	EALPHyy	EALPIyy	EALPJyy	EALPKyy	EALPLyy
Calif-Orecon Border Opk	Proxy	ECOQB00	ECOQAyy	ECOQByy	ECOQCyy	ECOQDyy	ECOQEyy	ECOQFyy	ECOQGyy	ECOQHyy	ECOQIyy	ECOQJyy	ECOQKyy	ECOQLyy
Calif-Orecon Border Pk	Proxy	ECOPB00	ECOPAyy	ECOPByy	ECOPCyy	ECOPDyy	ECOPEyy	ECOPFyy	ECOPGyy	ECOPHyy	ECOPIyy	ECOPJyy	ECOPKyy	ECOPLyy
East Colorado Opk	Proxy	EWEQB00	EWEQAyy	EWEQByy	EWEQCyy	EWEQDyy	EWEQEyy	EWEQFyy	EWEQGyy	EWEQHyy	EWEQIyy	EWEQJyy	EWEQKyy	EWEQLyy
East Colorado Pk	Proxy	EWEPB00	EWEPAyy	EWEPByy	EWEPCyy	EWEPDyy	EWEPEyy	EWEPFyy	EWEPGyy	EWEPHyy	EWEPIyy	EWEPJyy	EWEPKyy	EWEPLyy
Four Corners Opk	Proxy	EFCQB00	EFCQAyy	EFCQByy	EFCQCyy	EFCQDyy	EFCQEyy	EFCQFyy	EFCQGyy	EFCQHyy	EFCQIyy	EFCQJyy	EFCQKyy	EFCQLyy

M2MS-POWER WEST REGION SYMBOLS FOR 20 YEAR FORWARD CURVES (BATE CODE:U)

	Location Category	BOM	January	February	March	April	May	June	July	August	September	October	November	December
Four Corners Pk	Proxy	EFCPB00	EFCPAyy	EFCPByy	EFCPCyy	EFCPDyy	EFCPEyy	EFCPFyy	EFCPGyy	EFCPHyy	EFCPIyy	EFCPJyy	EFCPKyy	EFCPLyy
Mead Opk	Proxy	EMDQB00	EMDQAyy	EMDQByy	EMDQCyy	EMDQDyy	EMDQEyy	EMDQFyy	EMDQGyy	EMDQHyy	EMDQIyy	EMDQJyy	EMDQKyy	EMDQLyy
Mead Pk	Proxy	EMDPB00	EMDPAyy	EMDPByy	EMDPCyy	EMDPDyy	EMDPEyy	EMDPFyy	EMDPGyy	EMDPHyy	EMDPIyy	EMDPJyy	EMDPKyy	EMDPLyy
Mid-Columbia Opk	Market	EMCQB00	EMCQAyy	EMCQByy	EMCQCyy	EMCQDyy	EMCQEyy	EMCQFyy	EMCQGyy	EMCQHyy	EMCQIyy	EMCQJyy	EMCQKyy	EMCQLyy
Mid-Columbia Pk	Market	EMCPB00	EMCPAyy	EMCPByy	EMCPCyy	EMCPDyy	EMCPEyy	EMCPFyy	EMCPGyy	EMCPHyy	EMCPIyy	EMCPJyy	EMCPKyy	EMCPLyy
NOB, Nevada-Oregon Border Opk	Proxy	ENOQB00	ENOQAyy	ENOQByy	ENOQCyy	ENOQDyy	ENOQEyy	ENOQFyy	ENOQGyy	ENOQHyy	ENOQIyy	ENOQJyy	ENOQKyy	ENOQLyy
NOB, Nevada-Oregon Border Pk	Proxy	ENOPB00	ENOPAyy	ENOPByy	ENOPCyy	ENOPDyy	ENOPEyy	ENOPFyy	ENOPGyy	ENOOHyy	ENOPIyy	ENOPJyy	ENOPKyy	ENOPLyy
North Path 15 Opk	Market	ENPQB00	ENPQAyy	ENPQByy	ENPQCyy	ENPQDyy	ENPQEyy	ENPQFyy	ENPQGyy	ENPQHyy	ENPQIyy	ENPQJyy	ENPQKyy	ENPQLyy
North Path 15 Pk	Market	ENPPB00	ENPPAyy	ENPPByy	ENPPCyy	ENPPDyy	ENPPEyy	ENPPFyy	ENPPGyy	ENPPHyy	ENPPIyy	ENPPJyy	ENPPKyy	ENPPLyy
Palo Verde Opk	Market	EPVQB00	EPVQAyy	EPVQByy	EPVQCyy	EPVQDyy	EPVQEyy	EPVQFyy	EPVQGyy	EPVQHyy	EPVQIyy	EPVQJyy	EPVQKyy	EPVQLyy
Palo Verde Pk	Market	EPVPB00	EPVPAyy	EPVPByy	EPVPCyy	EPVPDyy	EPVPEyy	EPVPFyy	EPVPGyy	EPVPHyy	EPVPIyy	EPVPJyy	EPVPKyy	EPVPLyy
Pinnacle Peak Opk	Proxy	EPNQB00	EPNQAyy	EPNQByy	EPNQCyy	EPNQDyy	EPNQEyy	EPNQFyy	EPNQGyy	EPNQHyy	EPNQIyy	EPNQJyy	EPNQKyy	EPNQLyy
Pinnacle Peak Pk	Proxy	EPNPB00	EPNPAyy	EPNPByy	EPNPCyy	EPNPDyy	EPNPEyy	EPNPFyy	EPNPGyy	EPNPHyy	EPNPIyy	EPNPJyy	EPNPKyy	EPNPLyy
South Path 15 Opk	Market	ESPQB00	ESPQAyy	ESPQByy	ESPQCyy	ESPQDyy	ESPQEyy	ESPQFyy	ESPQGyy	ESPQHyy	ESPQIyy	ESPQJyy	ESPQKyy	ESPQLyy
South Path 15 Pk	Market	ESPPB00	ESPPAyy	ESPPByy	ESPPCyy	ESPPDyy	ESPPEyy	ESPPFyy	ESPPGyy	ESPPHyy	ESPPIyy	ESPPJyy	ESPPKyy	ESPPLyy
Utah Opk	Proxy	EUTQB00	EUTQAyy	EUTQByy	EUTQCyy	EUTQDyy	EUTQEyy	EUTQFyy	EUTQGyy	EUTQHyy	EUTQIyy	EUTQJyy	EUTQKyy	EUTQLyy
Utah Pk	Proxy	EUTPB00	EUTPAyy	EUTPByy	EUTPCyy	EUTPDyy	EUTPEyy	EUTPFyy	EUTPGyy	EUTPHyy	EUTPIyy	EUTPJyy	EUTPKyy	EUTPLyy

* The symbols in this table are displayed in summation notation. For example, to derive the symbol for ISO-NE NE-Mass Hub Pk January 2017, replace the yy inENMBAyy from the table above with 17 to make ENMBA17.

WEST REGION

Alberta
Alberta is based on the on peak and off peak mathematical averages of the hourly pool prices published by AESO on their website www.aeso.ca.

California-Oregon Border
California-Oregon Border comprises the Captain Jack and Malin substations on the AC transmission system between Oregon and California.

East Colorado
East Colorado is based on power delivered to the DC tie line in Lamar, Colorado.

Four Corners
Four Corners comprises the switchyard of the coal-fired Four Corners power plant in Fruitland, New Mexico, located in the Northwestern corner of the state where Arizona, Colorado, New Mexico and Utah meet.

Mead
Mead comprises the switchyard at the Hoover Dam on the Colorado River, forming Lake Mead near Las Vegas, Nevada.

Mid-Columbia
Mid-Columbia is a power trading hub for the Northwest U.S. comprising the control areas of three public utility districts in Washington that run hydro electric projects on the Columbia River. The three PUDs are Grant, Douglas and Chelan. Hydro projects include Wells, Rocky Reach, Rock Island, Wanapum and Priest Rapids dams.

NOB, Nevada-Oregon Border
Nevada-Oregon Border is part of the Pacific DC Intertie that connects the Pacific Northwest directly with Southern California. The DC Intertie connects the Celio DC Converter station near The Dalles, Oregon with the Sylmar substation north of Los Angeles, California.

North Path 15
North Path 15, or NP 15, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by CAISO on their website www.caiso.com.

Palo Verde
Palo Verde comprises the switchyard at the Palo Verde nuclear power station west of Phoenix, Arizona.

Pinnacle Peak
Pinnacle Peak comprises three substations northeast of Phoenix, Arizona and west of Scottsdale Arizona. The three substations are operated individually by Arizona Public Service, US Bureau of Reclamation Lower Colorado Region and Salt River Project.

South Path 15
South Path 15, or SP 15, is based on the on peak and off peak mathematical averages of the hourly day ahead LMP prices published by CAISO on their website www.caiso.com.

Utah
Utah, or Mona, comprises the Mona substation in central Utah, directly south of Salt Lake City and linked to major generating units in the region, such as the Intermountain Power Project.

Platts produces heat rate curves for the Power/Gas hub pairs shown below:

POWER/GAS HUB PAIRS

Power Hub Name	Gas Hub 1	Gas Hub 2	Gas Hub 3	Gas Hub 4
Northeast Region				
ISO-NE NE-Mass	Algonquin CG	Tenn Zn6 Dlvd		
ISO-NE New Hampshire	Algonquin CG	Tenn Zn6 Dlvd		
ISO-NE SE-Mass	Algonquin CG	Tenn Zn6 Dlvd		
ISONE Vermont Zone	Algonquin CG	Tenn Zn6 Dlvd		
ISO-NE W Central Mass	Algonquin CG	Tenn Zn6 Dlvd		
NEPOOL Connecticut	Iroquois Zn2	Tenn Zn6 Dlvd		
NEPOOL Mass Hub	Algonquin CG	Tenn Zn6 Dlvd		
NEPOOL North	Dracut MA	Iroquois Recpts		
NEPOOL RI	Algonquin CG	Tenn Zn6 Dlvd		
NY ISO Mohawk Valley Zone (E)	Transco Zn6 NY	TX Eastern M-3		
NY ISO Zone A (West)	Niagara	Dawn Ontario	Iroquois Recpts	
NY ISO Zone C (Central)	Niagara	Dawn Ontario		
NY ISO Zone D (North)	Iroquois Receipts	Tenn Zn6 Dlvd		
NY ISO Zone F (Capital)	Transco Zn6 NY	Iroquois Zn2		
NY ISO Zone G (Hudson Val)	Iroquois Zn2	Transco Zn6 NY		
NY ISO Zone J (NYC)	Transco Zn6 NY	TX Eastern M-3		
NY ISO Zone K (Long Island)	Transco Zn6 NY			
Ontario	Dawn Ontario			
Southeast Region				
Florida	FL Gas Zn3	Florida CG		
Into Entergy	Henry Hub	CenterPoint E	Texas Gas Zn 1	TETCO M1
Into Southern	Transco Zn4	FL Gas Zn3		
Into TVA	TETCO M1	Tenn 100 Leg		
SPP North	Nrthrn Ventura	Nrthrn NG Demarc		
SPP South	Panhandle TX-OK	Oneok OK		
Vacar	Transco Zn5 Dlv			
West Region				
Alberta	TC Alb AECO-C			
Calif-Oregon Border	PG&E Malin			
East Colorado	CHEYENNE	NW WY Pool/Rky		
Four Corners	El Paso SanJuan			
Mead	SoCal Gas			
Mid-Columbia	NW Can Bd Sumas			

POWER/GAS HUB PAIRS

Power Hub Name	Gas Hub 1	Gas Hub 2	Gas Hub 3	Gas Hub 4
North Path 15	PG&E CG			
Palo Verde	SoCal Gas	El Paso Permian		
South Path 15	SoCal Gas	PG&E South		
Utah	KERN RIVER OPAL	NW WY Pool/Rky		
PJM/MISO Region				
Alliant West	Nrthrn Ventura	Nrthrn NG Demarc		
Manitoba/Saskatchewan	Emerson			
Michigan	Mich Con CG	Cons Energy CG		
MISO Arkansas Hub	CenterPoint E	Texas Gas Zn 1	TETCO M1	
MISO Illinois Hub	Chicago CG			
MISO Indiana Hub	Chicago CG			
MISO Louisiana Hub	Col Gulf LA	TX Eastern E LA		
MISO Minn Hub	Nrthrn Ventura	Emerson		
MISO Texas Hub	TX Eastern E TX	NGPL Texok Zn		
PJM AD Hub	Mich Con CG	Chicago CG		
PJM AECO	Col Gas Appal	Dominion S Pt		
PJM AEP	Dominion S Pt	Lebanon Hub-Ohio		
PJM APS	Col Gas Appal	Dominion S Pt		
PJM ATSI	Dominion S Pt	Lebanon Hub-Ohio		
PJM BGE Zone	TX Eastern M-3	Transco Zn6 xNY		
PJM ComEd	Chicago CG	Lebanon Hub-Ohio		
PJM DEOK	Dominion S Pt	Lebanon Hub-Ohio		
PJM DPL	TX Eastern M-3	Col Gas Appal		
PJM Duquesne	Dominion S Pt	Transco Zn6 xNY		
PJM Eastern Hub	TX Eastern M-3	Transco Zn6 xNY		
PJM FE Ohio	Dominion S Pt	Lebanon Hub-Ohio		
PJM JCPL Zone	Transco Zn6 xNY	TX Eastern M-3		
PJM METED	TX Eastern M-3	Transco Zn6 xNY		
PJM NI Hub	Chicago CG			
PJM PECO Zone	TX Eastern M-3	Transco Zn6 xNY		
PJM PENELEC	Dominion S Pt	Transco Zn5 Dlv		
PJM PEPCO Zone	Transco Zn5 Dlv	TX Eastern M-3	Dominion S Pt	
PJM PPL Zone	LEIDY	Dominion S Pt		
PJM PSEG Zone	TX Eastern M-3	Transco Zn6 xNY		
PJM Western Hub	TX Eastern M-3	Dominion S Pt		
Southern Illinois	Chicago CG			
Wisconsin	ANR ML 7			

POWER/GAS HUB PAIRS

Power Hub Name	Gas Hub 1	Gas Hub 2	Gas Hub 3	Gas Hub 4
ERCOT Region				
ERCOT Houston Hub	Houston ShipChl	Katy		
ERCOT North Hub	TX Eastern E TX			
ERCOT South Hub	Tenn Zn0	NGPL S TX	Agua Dulce Hub	
ERCOT West Hub	Waha	Transwestn Perm		

IMPORTANT DISCLOSURE

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REVISION HISTORY

February 2017: Platts revamped this Methodology And Specifications Guide effective February 2017. This revision was completed to remove reference to the following discontinued products: 10 & 20 year historical volatility curves (which are being replaced by implied volatility curves), spark spreads and correlation curves. This revision was also completed to include coverage changes to the M2MS-Power product. Specifically, 6 hubs were added to bring the total number of hubs covered to 72.

November 2015: Platts revised this Methodology and Specifications Guide effective November 2015. This revision was completed to include coverage and definition changes to the M2MS-Power product – 5 location additions, 1 location name change, and 5 location discontinuations. This revised guide also reflects a balance of the month definition.

April 2015: Platts revamped this Methodology And Specifications Guide effective March 2015.This revamp was completed to enhance the clarity and usefulness of the guide, and to introduce greater consistency of layout and structure across all published methodology guides. Methodologies for market coverage were not changed through this revamp, unless specifically noted in the methodology guide itself.

The delivery of all this power enables Canada to avoid building roughly 1,300 MW of new generation to meet its demand for electricity. As a comparison, Columbia Generating Station, the Northwest's only nuclear power plant, has a capacity of about 1,150 MW. When the value of the energy, capacity and flexibility are factored together, BPA currently estimates that if Canada were to replace the entire Entitlement with its own new gas generating resource, the cost would be roughly $250 million to $350 million each year. This range — which reflects low and high assumptions about fuel prices for a replacement power plant — serves as a good proxy of the Entitlement's value to Canada.

Certainly, the world has changed over the past 50 years. Canada's Treaty dams are in place and will be more than fully paid for by 2024. Given this reality, the U.S. Entity prefers to evaluate the Entitlement value, not in terms of whether the Treaty dams exist but on whether Canada and the United States continue to work together to coordinate hydro system operations or choose to operate independently.

The U.S. Entity is studying the difference in value between coordinated and uncoordinated cross-border hydro system operations. Initial estimates indicate that the power benefit from coordinated Treaty storage operations, compared to uncoordinated operation, is $26 million a year, a sum much smaller than those produced using either the current Canadian Entitlement calculations or the estimated cost of a replacement resource. Analyses continue to be conducted.

Considerations for Treaty Review

From a power perspective, the U.S. Entity believes that by 2024 the United States will have fully compensated Canada. If the formula is updated to reflect the post-2024 value of a coordinated hydro system operation, the Canadian share of downstream power benefits will be significantly lower than

Increased hydroelectric production under the Treaty has benefitted both Canada and the United States.

the established 450 aMW forecast for U.S. returns. The method for calculating these benefits is explicitly fixed through 2024 and cannot be significantly changed without renegotiating the Treaty's Entitlement methodology.

Through the Treaty Review process, which includes input from regional stakeholders, the U.S. Entity is evaluating what changes to propose to the Canadian Entitlement calculation. BPA also must estimate the value of power benefits associated with continuing the Treaty. Any proposed change in the calculations would have to be mutually agreeable to the United States and Canada.

For more information

For information regarding the Columbia River Treaty 2014/2024 Review, please visit *www.crt2014-2024review.gov* or email us at *treatyreview@bpa.gov*, or call the Bonneville Power Administration at 800-622-4519 or the U.S. Army Corps of Engineers at 503-808-4510.

This publication of the Columbia River Treaty 2014/2024 Review was developed to inform you of issues surrounding the Columbia River Treaty. It is published by the U.S. Entity, which includes the Bonneville Power Administration and the U.S. Army Corps of Engineers.

US Army Corps of Engineers

BONNEVILLE POWER ADMINISTRATION

April 2013
United States Entity

U.S. ARMY CORPS OF ENGINEERS • BONNEVILLE POWER ADMINISTRATION

Columbia River Treaty 2014/2024 Review

Canadian Entitlement

What is the Canadian Entitlement and how did it come to be?

Before the Columbia River Treaty, high springtime flows on the Columbia River frequently overwhelmed the ability of the United States' downstream infrastructure to generate power and manage flood risk. The four dams built under the terms of the 1964 Columbia River Treaty (three in Canada and a fourth in Montana) approximately doubled the water storage capacity on the Columbia River system. The Treaty and Treaty dams enhanced the cooperation between the U.S. and Canada, helping to ensure mutually advantageous operation of the dams by improving the ability to regulate the timing of streamflows by capturing high spring flows and releasing this water more gradually over the summer, fall and winter months. Overall, the coordinated storage and regulation of flows between the United States and Canada vastly improved both hydropower production and flood mitigation in the Columbia Basin.

The increased power generation in the United States resulting from the operation of additional storage capacity created by the three Treaty dams built in Canada is referred to as the downstream power benefits. The Treaty negotiators in the early 1960s agreed that the United States and Canada would equally share these benefits, which are calculated annually according to a complex method negotiated among the Treaty's authors. It is essentially a theoretical value placed on the additional generation. Canada's half of these calculated downstream power benefits is called the Canadian Entitlement.

The Canadian Entitlement is not solely a U.S. federal responsibility. Chelan County PUD, Douglas County PUD and Grant County PUD — known as the Mid-Columbia PUDs — contribute approximately 27 percent of the power delivered under the Canadian Entitlement because they own and operate five hydroelectric projects on the Columbia River that benefit from coordinated river operations under the Treaty.

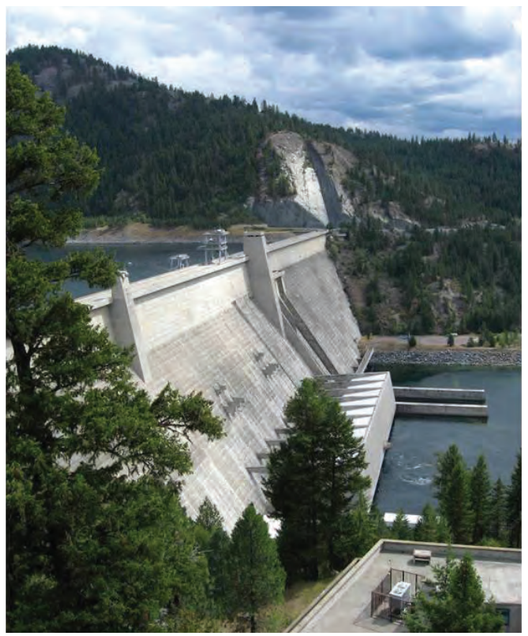
The U.S. Entity believes that the Canadian Entitlement, combined with a separate flood risk management payment to Canada, has more than repaid the cost to Canada of the three dams over the Treaty's expected minimum life of approximately 50 years (beginning after the last of these dams was completed in 1973).

In other words, the U.S. Entity's view is the Canadian Entitlement and the flood risk management payment were designed to produce a value that reflected an appropriate total payment to Canada for the cost of Treaty dams by the time the Treaty could be terminated in 2024. While the Treaty authors did their best to forecast conditions far into

Duncan Dam was the first of four new dams constructed under the Treaty.

Keenleyside Dam, also known as Arrow in the U.S., started operating in 1968.

Mica Dam was the final Treaty dam built in Canada.



Libby Dam, the last Treaty dam to become operational is the only Treaty dam in the United States.

the future, their 1960s-era calculations overestimated regional growth in the demand for electricity and did not anticipate modern constraints on the operation of the dams to protect threatened and endangered species.

Also, they could not have anticipated the significant regional development of conservation and renewable energy resources and other electricity market factors, all of which influence the value of power in the region. In short, the U.S. Entity believes that over the life of the original Treaty, the U.S. will have fully compensated Canada for its investments in Treaty dams.

The Past

When the Treaty was enacted, Canada did not need the power provided through the Canadian Entitlement to meet its demand for electricity. Thus, it decided to sell that power to utilities in the United States for $254 million over the first 30 years of the Treaty's term. This transaction covered almost all of the original capital cost of the Canadian Treaty dams.[1]

The United States made the last payment under the 30-year power sales contract in 2003. Now, the U.S. delivers Canadian Entitlement power directly to Canada over the Bonneville Power Administration's Northern Intertie at the Canada-U.S. border. This delivery ranges from 1,176 to 1,369 megawatts (MW) of capacity and 465 to 567 annual average megawatts (aMW) of energy. As a reference point, one average megawatt is enough energy to power 730 typical Northwest homes.

Capacity refers to the ability to generate or transmit electricity; this value reflects the maximum amount of power that Canada could request over a single hour. The energy Entitlement is the average amount of electricity actually delivered to Canada over a period of one year. This power delivery is a combination of federal and non-federal power, reflecting the mix of hydropower generation resources in the Columbia River Basin.

The original Treaty negotiators expected the downstream power benefits to diminish significantly over time. The final Treaty negotiations forecast the Canadian Entitlement for the 2010 to 2024 period to be about 134 aMW of energy and zero MW capacity, meaning Canada would have no flexibility regarding when the United States returned Entitlement power. Using the current calculation methodology, the 2025 forecast is 450 aMW of energy and about 1,300 MW of capacity.

[1] *Hugh Keenleyside, 1974, "Ten Years Later, the Results of the Columbia River Treaty."*

The Future

The Canadian Entitlement currently is based on an estimation of how much hydropower could be produced with and without the additional water storage provided by the Treaty dams. There is more electricity generated when it is assumed the dams are in place (remember, this methodology uses a negotiated formula to calculate the theoretical value of the additional generation), and the Canadian Entitlement is equal to one-half of that assumed increase in generation.

The structure of the Canadian Entitlement makes it an extremely valuable commodity in the utility industry. Electricity is more valuable when it is virtually guaranteed to be available, or "reliable," and when its delivery can be shifted to times of high demand, or "flexible." The Canadian Entitlement offers both of these attributes.

To highlight the flexibility of the Canadian Entitlement, the current agreement allows Canada to select which hours of the following day that it wants anywhere from zero to 1,321 MW of power to be delivered to the B.C. border. Similarly, to underscore the reliability of the Canadian Entitlement, these returns from the U.S. to Canada are virtually guaranteed, barring any significant transmission system problems or other unusual circumstances. During the operating year of 2012, the U.S. delivered Canadian Entitlement power 99.94 percent of the time. In the case of the few hours when deliveries were reduced, they were made up in a week or less.

The Columbia River Treaty 2014/2024 Review

The coordinated operation of the many dams and reservoirs under the Columbia River Treaty has provided significant flood risk management and hydropower benefits for both the United States and Canada. The Treaty calls for two "entities" to implement the Treaty, one for the U.S. and one for Canada.

The U.S. Entity, appointed by the president, consists of the BPA administrator and the Northwestern Division engineer of the U.S. Army Corps of Engineers. The Canadian Entity, appointed by the Canadian cabinet, is the British Columbia Hydro and Power Authority (BC Hydro).

While the Treaty has no specified end date, it contains provisions that will change its implementation in 2024. Additionally, either Canada or the U.S. may unilaterally terminate most provisions of the Treaty in 2024, with a minimum of 10 years' advance notice, hence the focus on 2014 and 2024.

The U.S. Entity is undertaking a series of studies regarding current and potential future operations under the Treaty. The goal is a recommendation from the U.S. Entity to the U.S. Department of State by the end of 2013 on which elements the Pacific Northwest would like the Department of State to pursue in negotiations with Canada.

Collectively known as the Columbia River Treaty 2014/2024 Review, this multi-year effort will provide information critical to a U.S. Entity recommendation through evaluation of the value of Treaty benefits to the region and consideration of contemporary concerns that reach beyond flood risk management and power generation.

Integral to the Treaty Review process is the U.S. Entity's direct consultation with the Sovereign Review Team, comprised of representatives of the four Northwest states, 15 tribal governments and 11 federal agencies. Supporting the Sovereign Review Team is the Sovereign Technical Team, responsible for completing the technical work that informs the Sovereign Review Team and the U.S. Entity.

U.S. President Dwight D. Eisenhower and Canadian Prime Minister John Diefenbaker sign the Columbia River Treaty in 1961.

ADMINISTRATOR'S DECISION RECORD

NON-TREATY STORAGE AGREEMENT WITH BC HYDRO

1. DECISION

This document supports a decision by the Administrator of the Bonneville Power Administration (BPA) to enter into an agreement (the 2012 Non-Treaty Storage Agreement [2012 NTSA]) with the British Columbia Hydro and Power Authority (BC Hydro). The 2012 NTSA provides for additional use of existing storage space on the Columbia River in Canada for increased value to the region. The 2012 NTSA does not require any particular operation of the storage space but provides the opportunity for both BPA and BC Hydro (jointly, the Parties) to shape flows within existing downstream requirements and utilize the additional flexibility to create power and nonpower benefits for the parties and the region. This flexibility is expected to provide additional power benefits for the federal system, downstream mid-Columbia projects, and BC Hydro. The 2012 NTSA fulfills an objective called for in NOAA Fisheries 2008/2010 Biological Opinion on the Federal Columbia River Power System (FCRPS) to seek a long-term agreement on use of non-Treaty space in Canada to provide benefits to Endangered Species Act (ESA) listed fish. The 2012 NTSA allows for coordinated use of non-Treaty storage in Canada to shape flows within the year for fisheries benefits, and provides up to an additional half million acre-feet water to benefit fish in the lowest water conditions.

2. BACKGROUND

a. Non-Treaty Storage and Relationship to the Columbia River Treaty

Coordination of the Pacific Northwest and BC Hydro systems began in 1964 with ratification of the Columbia River Treaty (Treaty). Under the Treaty, Canada was required to construct and operate 15.5 million acre-feet (MAF) of storage in Canada at Mica, Arrow, and Duncan projects. The United States was allowed to construct 5 MAF of storage at Libby Dam. BC Hydro designed and built Mica dam to store more water than the 7 MAF required under the Treaty. As a result, an additional 5 MAF of usable storage is available at Mica.

This extra storage is referred to as non-Treaty storage and is not operated under the terms of the Treaty. The Treaty limits use of non-Treaty storage to actions that do not reduce Treaty flood control and power benefits. Within that constraint, BC Hydro has used the storage space for its benefit by redistributing water among its reservoirs. BPA access to this storage is obtained only through negotiation of operational agreements that provide mutual benefits to the BPA and BC Hydro. Absent an agreement, the benefits of releasing water from Arrow across the Canada-U.S. border cannot be achieved.

Beginning in the mid-1990's, Biological Opinion objectives included seeking use of storage in Canada to improve flows for fisheries in the U.S. through use of both Treaty and non-Treaty storage. Under the Treaty, the U.S. and Canada have developed Treaty supplemental operating agreements within the operating year to provide additional flow

augmentation for U.S. fisheries in exchange for trout spawning and whitefish protection downstream of Arrow in Canada. Most typically this results in storage of 1 MAF of water in Treaty space during the winter for release in the May-July period. These agreements do not provide any ability to shape Treaty flows from one operating year to the other, from July into August for example, or for additional water in a dry year. These annually negotiated agreements will only be successful to the extent that mutual benefits can be obtained for both Canada and the U.S. In order to have greater flexibility to shape flows from Canada, access to non-Treaty storage is needed.

b. Prior Agreements

BPA and BC Hydro signed the first long-term non-Treaty storage agreement (NTSA) in 1984 to provide mutual energy benefits and to address a dispute over the initial filling of Revelstoke reservoir. The 1984 NTSA included access to 1 MAF of non-Treaty storage each for BPA and BC Hydro. In 1990, BPA and BC Hydro expanded the agreement to use 4.5 MAF of the storage continuously and extended the termination date from 1993 to 2003 (later extended to 2004). Companion agreements with some of the owners, operators, and power purchasers from five non-federal generating projects on the Columbia River were also developed under both prior long-term agreements.

Non-Treaty storage provides additional storage needed to shape flows from Canada both within the year and between years, consistent with the Treaty. Because non-Treaty storage may not be operated to reduce power and flood control benefits, BPA and BC Hydro seek opportunities to provide power as well as non-power benefits under non-Treaty storage agreements. During the term of the 1990 NTSA, that long-term agreement provided terms under which arrangements to shape flows through the spring and summer periods could be developed.

Following expiration of release provisions under the 1990 NTSA in 2004, short-term stand-alone agreements were negotiated, when possible. Such agreements were developed each year from 2006 through 2011 with the amount and shape of water stored and released coordinated in-season with fisheries managers. All of the seasonal agreements involved storing water in the spring period when flows were higher and releasing water later in the summer when flows were lower. The amount of water stored and released depended on the water conditions including the seasonal flow volume and shape. This operation was considered beneficial for fish and also provided power benefits due to the higher summer electricity prices compared to those in the spring.

In 2010, as refill of accounts under the 1990 NTSA neared completion, BPA and BC Hydro agreed to seek a new long-term NTSA that would provide flexibility to both Parties. Such an agreement could provide greater power and non-power benefits, including fisheries benefits, than could be achieved through continued use of annual seasonal agreements.

c. Mid-Columbia Participants

The 2012 NTSA is not expected to result in companion agreements with any of the mid-Columbia participants. Actions under the 2012 NTSA with respect to downstream parties are addressed under the 1997 Pacific Northwest Coordination Agreement.

d. Negotiation of 2012 NTSA

BPA held several meetings with federal agencies, states, and tribes to solicit input for negotiating a new long-term NTSA and to report on progress during the negotiations with BC Hydro.

The feedback BPA received during these meetings was considered by BPA in discussions with BC Hydro. During these discussions, BPA and BC Hydro developed non-binding terms for negotiating an NTSA. These terms were captured in a term sheet that was released for public review in the U.S. and Canada. BPA held a series of open house meetings in the region to provide information and answer questions related to the 2012 NTSA terms. BPA held public meetings in Spokane, Boise, Portland, and Seattle. In addition, BPA conducted two conference calls with customers, met with tribes and other interested groups, and published information in the BPA Journal. Written information, including a Fact Sheet and Key Messages also were provided to designated BPA staff to assist them in informing public interest groups, power utility groups and customers, state and local officials and Northwest delegation members about the NTSA Term Sheet and draft contract language. BPA accepted public comments on the draft contract for a 10-day period in March 2012; there were no comments submitted that opposed the contract language.

During outreach efforts, most questions related to one of two general topics; 1) how the 2012 NTSA would create power benefits for the region and for BC Hydro, and 2) how the provisions related to fisheries benefits would work, specifically the BPA dry water provisions. During meetings and calls, questions were answered and additional information was provided, when requested.

Staff from the Shoshone Paiute Tribes of the Duck Valley Indian Reservation raised concerns regarding the level of environmental analysis that would be conducted for the 2012 NTSA under the National Environmental Policy Act (NEPA). BPA environmental staff, NEPA Compliance Officer, and BPA's lead negotiator met with the Shoshone Paiute Tribes and other interested Upper Snake River Tribes to follow up on concerns raised and answer additional questions regarding the 2012 NTSA. BPA has conducted environmental review of the 2012 NTSA in accordance with the U.S. Department of Energy NEPA implementing regulations (please see Section 5. NEPA Analysis of this decision record).

BPA and BC Hydro drafted the 2012 NTSA consistent with the Term Sheet made public in May 2011. The 2012 NTSA Final draft contract was made available for public review and comment on March 7, 2012.

3. PUBLIC REVIEW AND COMMENT

BPA provided 10 days to allow public review and comment on the draft 2012 NTSA, which closed March 16, 2012. BPA received one comment from the Springfield Utility Board (SUB). SUB expressed concern over whether the 2012 NTSA could potentially and unintentionally impact and/or interfere with BPA's Environmental Redispatch and Oversupply efforts. SUB believes any lost revenues associated with the 2012 NTSA should be redistributed among BPA customers.

BPA appreciates SUB's concern; however SUB's concern is misplaced. Rather than adversely impacting BPA's efforts to address Environmental Redispatch and Oversupply, the 2012 NTSA is expected to provide additional flexibility that can help manage and potentially improve conditions with respect to Environmental Redispatch and Oversupply. The 2012 NTSA will provide additional flexibility to reduce flows and spill during periods when dissolved gas levels caused by spill exceed state standards. This flexibility will be used to help manage oversupply problems. Overall, the 2012 NTSA is expected to produce power benefits on the federal system, providing an economic benefit to BPA's customers and, in accordance with the Treaty, must be operated so that the power and flood control benefits of Treaty operating plans are not reduced.

4. SUMMARY OF AGREEMENT

The 2012 NTSA (contract 12PG-10002) will replace both the 1990 long-term NTSA (contract DE-MS79-90BP92754), which fully expired in January 2011, and the September 2011 non-Treaty storage "Bridge" agreement (contract 11PB-21385) which expires March 30, 2012. The NTS "Bridge" agreement was designed to transition to the 2012 NTSA upon execution. The 2012 NTSA expires on Sept. 15, 2024, unless either party terminates under the early termination provisions.

Like previous non-Treaty storage agreements, and consistent with the requirement of the Treaty regarding non-Treaty storage use, operations under the 2012 NTSA will be conducted in a manner that does not reduce flood control and power benefits under the Columbia River Treaty. Absent an agreement such as this 2012 NTSA, BPA does not have access to non-Treaty storage.

The 2012 NTSA will provide opportunities to achieve benefits for ESA-listed fish by providing flexibility for BPA to store water when it is abundant and exceeds fish requirements in the spring and then release that water in the summer to provide water when Columbia River flows are low. This operation benefits fish by providing needed summer flows and also provides power benefits by increasing hydro generation when it is needed to meet summer loads. In the driest water conditions, the proposed terms will allow BPA to release water in the spring to provide additional water for fish.

The 2012 NTSA will also provide additional flexibility to reduce flows and spill during periods when dissolved gas levels (caused by spill) exceed state standards and to reduce or increase flows to move generation into higher value periods.

Under terms of the 2012 NTSA:

- BPA and BC Hydro each have continuing access to 1.5 MAF of active storage.
- BC Hydro may make available from time to time recallable accounts of 1 MAF each for BPA and BC Hydro.
- With the exception of limited firm release rights by both BPA and BC Hydro during dry water conditions, all water transactions are by mutual agreement and are coordinated on a weekly basis.
- BPA has firm release rights of up to 0.5 MAF of water releases in spring of years within the lowest 20 percent of water conditions if not used in the prior year.
- BC Hydro benefits from the energy value of generation changes at downstream U.S. federal hydro projects that result from its water transactions
- BC Hydro's benefits are either delivered as energy at the B.C./U.S. border or are financially settled with the exception of BC Hydro's firm energy benefits, which are always delivered to the border with all transmission costs paid by BC Hydro.

BPA compensates BC Hydro for headlosses on the BC Hydro system resulting from BPA's non-Treaty storage use. As with the current non-Treaty storage "Bridge" agreement, no energy value is associated with BPA water transactions under the 2012 NTSA.

BC Hydro water transactions are converted to energy values using the federal downstream projects' daily conversion factor and an agreed daily flat mid-C index price, limited to minimum on-peak (HLH) and off-peak (LLH) prices of $0.00. If BPA's policy changes such that BPA participates in negative markets, this minimum price provision will be re-visited. The energy values are tracked and cumulated over time as an energy benefit. The benefit may be delivered as energy upon request by the party owed by coordinating energy deliveries on a weekly basis, up to 300 MW, uniformly on light load hours. Unless otherwise agreed, any remaining energy benefit will be settled financially in September each year.

5. NEPA ANALYSIS

a. NEPA Evaluation

BPA has reviewed the 2012 NTSA for potential environmental effects that could result from its implementation, consistent with NEPA, 42 U.S.C. § 4321, et seq. Based on this review, BPA has determined that the 2012 NTSA falls within a class of actions that normally do not require environmental assessments or environmental impact statements and are excluded from further NEPA review pursuant to U.S. Department of Energy NEPA implementing procedures, which are applicable to BPA. More specifically, the 2012 NTSA falls within Categorical Exclusions B4.4 and B4.5, found at 10 CFR 1021, Subpart D, Appendix B. The B4.4 categorical exclusion involves actions of "[p]ower marketing services and power management activities (including, but not limited to, storage, load shaping and balancing, seasonal exchanges, and other similar activities), provided that the operations of generating projects would remain within normal operating limits." The B4.5 categorical exclusion involves actions of "[t]emporary adjustments to river operations to accommodate day-to-day river fluctuations, power demand changes, fish and wildlife conservation program requirements, and other external events, provided

that the adjustments would occur within the existing operating constraints of the particular hydrosystem operation." The environmental clearance memorandum that documents the categorical exclusion analysis and determination for the 2012 NTSA will be posted to BPA's website at:
http://efw.bpa.gov/environmental_services/categoricalexclusions.aspx

6. ALTERNATIVES CONSIDERED

a. Status Quo

Under the Status Quo, BPA would seek to negotiate seasonal agreements with BC Hydro for non-Treaty storage use for fisheries and other benefits. Specific agreement terms would be negotiated in season by mutual agreement. Typically these agreements have been for spring storage and summer release.

b. Implement the Proposed 2012 NTSA

The 2012 NTSA provides for long-term coordination and use of non-Treaty storage. BPA and BC Hydro would coordinate use of 1.5 MAF each of active storage on an ongoing basis under terms of the 2012 NTSA. BPA would gain firm rights to 0.5 Maf of water in the driest 20th percentile of water conditions, as described in NOAA's 2008/2010 Biological Opinion on the FCRPS, provided a dry year release has not occurred in the previous year and there is water in BPA's Active account. The 2012 NTSA also provides additional operational flexibility for power and non-power purposes including shaping flows from spring to summer to benefit U.S. fish. Accounting mechanisms are very similar to those used in recent short-term non-Treaty storage agreements with BC Hydro, however there are additional provisions for energy deliveries during the year and an option for financial settlement of obligations at the end of the year. The terms of the 2012 NTSA are consistent with the objectives under which BPA was to seek a long-term NTSA described in the NOAA Fisheries 2008/2010 Biological Opinion on the FCRPS.

c. No Action

Under the No-Action Alternative, there would be no negotiation of either short- or long-term non-Treaty storage agreements in the future.

7. DECISION FACTORS

a. Economic Factors

The greatest economic benefits to be gained under the 2012 NTSA result from operation of BPA's 1.5 MAF Active Account. The NTSA will provide flexibility to shape flows to better meet operational and marketing objectives. It is expected that operation of non-Treaty storage would result in federal power benefits of about $8 million per year, with additional benefits for downstream mid-C project owners and participants and BC Hydro. BC Hydro also achieves power benefits within its own system by increasing the flexibility and space to re-balance reservoir operations within Canada.

Energy deliveries under the NTSA are generally limited to 300 MW in light load hours and are designed to minimize transmission costs. It is expected that energy deliveries to BC Hydro will be made on transmission that is purchased for delivery of the Canadian Entitlement under the Treaty, but which is unused during most light load hours. Under the 2012 NTSA, all deliveries may be made on non-firm transmission and will not require additional firm transmission purchases.

b. Operational Factors

The 2012 NTSA will provide additional operating flexibility on BPA's system that would otherwise terminate with the NTS "Bridge" Agreement on 30 March 2012. Absent a new NTSA, weekly flows from Canada are established under the Treaty with limited flexibility to mutually agree to alternative and mutually-beneficial operations. The NTSA will allow additional shaping of flows into the U.S. for both power and non-power purposes beyond that afforded under the Treaty, including shaping within the operating year and between operating years.

c. Environmental Factors

1. Biological Opinion

   The 2012 NTSA fulfills an objective called for in the NOAA Fisheries 2008/2010 Biological Opinion on the FCRPS to seek a long-term non-Treaty storage agreement on the use of non-Treaty space in Canada to provide benefits to ESA-listed fish (Reasonable and Prudent Alternative (RPA)) Action 12. The 2012 NTSA provides the opportunity to shape flows within the year for fish benefit and provides up to an additional 0.5 MAF of water in the spring to benefit fish in lowest 20th percentile of water conditions, if not used in the prior year. This is consistent with the objective included in RPA Action 14, Dry Water Year Operations to explore opportunities to shape non-Treaty storage water to benefit ESA-listed fish in dry years.

   In addition, RPA Action 13 required BPA to coordinate with other Federal Agencies, States and the region's Tribes prior to any negotiations with BC Hydro to obtain ideas and information on possible points of negotiation and to report on major developments during negotiations. As described above in Section 2, BPA has met the coordination and inform requirements.

2. Additional Environmental Benefits

   In addition to providing flow benefits for fisheries during low and average water conditions, the NTSA may help reduce dissolved gas levels during high water conditions. One of the advantages of a long-term agreement is the ability to shape water from high flow years and periods, into lower flow periods and into low and average flow years. This can help reduce dissolved gas levels in very high flow conditions.

Because the NTSA does not require a specific operation, the flexibility it provides can be used to meet other non-power objectives that may occur in the future.

d. Statutory Authority

BPA has broad statutory authority to enter into agreements for greater operational flexibility.[1] Pursuant to this authority, the BPA Administrator has discretion to enter into 'such contracts, agreements, and arrangements . . . upon such terms and conditions and in such manner as he may deem necessary' to fulfill BPA's statutory purposes.[2] BPA has exercised this authority by entering into numerous operational agreements, including predecessor long-term and short-term agreements to the 2012 NTSA.

Equitable Treatment

BPA has a responsibility to protect, mitigate, and enhance fish and wildlife "in a manner that provides equitable treatment for such fish and wildlife with the other purposes for which such system and facilities are managed and operated."[3] BPA meets this responsibility on a system-wide basis, and not necessarily in every distinct transaction.[4]

In coordination with the Army Corps of Engineers and Bureau of Reclamation, BPA provides equitable treatment on a system-wide basis through its protection, mitigation and enhancement of fish and wildlife consistent with both the Northwest Power Council's Fish and Wildlife Program and meeting responsibilities under the Endangered Species Act to avoid jeopardizing listed species and adversely modifying or destroying designated critical habitat, and enabling their recovery.

The 2012 NTSA will further equitable treatment in several ways. For all types of water years it provides operating flexibility on BPA's system to allow for shaping for non-power objectives, including fisheries benefits, within the operating year and between operating years. The 2012 NTSA also provides up to an additional 0.5 MAF of firm rights to water in the spring of dry water years, if not used in the prior year, to augment fish flows. In addition to providing flow benefits for fisheries, the 2012 NTSA may help reduce dissolved gas levels during high water conditions. One of the advantages of a long-term agreement is the ability to shape water from high flow years and periods, into lower flow periods and into low and average flow years. This can help reduce dissolved has levels in very high flow conditions.

8. CONCLUSION

The 2012 NTSA has economic benefits to the Pacific Northwest, BPA, and BC Hydro. The 2012 NTSA has operational and environmental benefits as described in Section 7. It will provide 0.5 MAF of water in the spring in the driest 20th percentile of water conditions (if not

[1] See generally: The Bonneville Project Act, 16 USC 832; The Federal Columbia River Transmission System Act, 16 USC § 838; The Regional Preference Act 16 USC §837; and The Pacific Northwest Electric Power Planning and Conservation Act 16 USC §839
[2] 16 USC 832a(f)
[3] 16 USC 839b(h)(11)(A)
[4] Northwest Environmental Defense Center v BPA, 117 F.3d 1520 (9th Cir. 1997).

used in the previous year), a benefit that is not available under short-term seasonal agreements. It will provide additional flexibility and certainty for shaping flows through the spring and summer period and it will provide additional flexibility for shaping flows outside the April-August period and from year to year. All projects will continue to operate within their normal operating limits and, except for very modest and limited release rights in dry water conditions, either BPA or BC Hydro may limit transactions to protect non-power needs.

For the reasons stated above, BPA has decided to proceed with the Non-Treaty Storage Agreement, BPA Contract No. 12PG-10002 with BC Hydro.

Issued in Portland, Oregon.

S/ Wright

Stephen J. Wright
Bonneville Power Administration
Administrator and Chief Executive Officer

March 23, 2012
Date