ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple
Salt Lake City, UT 84116

February 6, 2023

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Wyoming Public Service Commission
2515 Warren Avenue, Suite 300
Cheyenne, Wyoming 82002

Attn: John Burbridge, Chief Counsel

Docket No. 20000-___-EN-23
Record No._____

RE: IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A WAIVER OF THE NON-SITUS CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR GATEWAY SEGMENT H, THE BOARDMAN TO HEMINGWAY TRANSMISSION PROJECT

Dear Mr. Burbridge:

Please find enclosed for filing Rocky Mountain Power's (the "Company") request for waiver of the non-situs certificate of public convenience and necessity ("CPCN") for the Boardman-to-Hemingway Transmission Project.

The request for waiver, application, testimony, supporting exhibits, and work papers are being provided in electronic format on the Docket Management System. One hardcopy of the public version of the filing is being provided to the Wyoming Public Service Commission ("Commission") to allow for public viewing.

The Company is respectfully requesting a determination by the Commission regarding the requested waiver of the non-situs CPCN and Advanced Review Process requirements within 20 business days of receiving this request and application.

Provided on the enclosed CDs are the non-confidential and confidential workpapers.

It is respectfully requested that all formal correspondence and staff requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon 97232

with copies to:

Stacy Splittstoesser
Wyoming Regulatory Affairs Manager
Rocky Mountain Power
315 W. 27th St.
Cheyenne, Wyoming 82001
E-mail: stacy.splittstoesser@pacificorp.com

John Hutchings
Carla Scarsella
Assistant General Counsel
Rocky Mountain Power
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
E-mail: john.hutchings@pacificorp.com
carla.scarsella@pacificorp.com

Katherine McDowell
Adam Lowney
McDowell Rackner & Gibson PC
419 SW 11th Avenue, Suite 400
Portland, Oregon 97205
E-mail: katherine@mrg-law.com
adam@mrg-law.com

If there are any informal questions related to this request for waiver and application, please feel free to contact Stacy Splittstoesser at (307) 632-2677.

Sincerely,

Joelle Steward

Joelle R. Steward
Senior Vice President, Regulation and Customer/Community Solutions

Enclosures

cc: Wyoming Industrial Energy Consumers
Wyoming Office of Consumer Advocate

John Hutchings
Carla Scarsella
Rocky Mountain Power
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
Telephone: (801) 220-4545
Facsimile: (801) 220-3299
Email: john.hutchings@pacificorp.com
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Katherine McDowell
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Portland, Oregon 97205
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adam@mrg-law.com

Attorneys for Rocky Mountain Power

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A WAIVER OF THE NON-SITUS CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR GATEWAY SEGMENT H, THE BOARDMAN TO HEMINGWAY TRANSMISSION PROJECT	Docket No. 20000-___-EN-23 (Record No. _______) **PETITION FOR CONFIDENTIAL TREATMENT AND PROTECTIVE ORDER**

PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company"), in accordance with Chapter 2, Section 30 of the Wyoming Public Service Commission's rules and Rule 26 of the Wyoming Rules of Civil Procedure, hereby requests that the Wyoming Public Service Commission ("Commission") approve the Company's "confidential" designation of certain testimony, exhibits and workpapers accompanying the request for waiver and Application in the above-captioned matter, based on the explanations set forth below. The testimony, exhibits, and workpapers are properly labeled as "confidential" and were provided electronically to the Commission. The Company anticipates that there could be additional data requests intervening parties and/or Commission staff that will request confidential information, and potentially, confidential testimony provided by the intervening parties or the Company.

In addition, the Company files with this Petition, as required by Chapter 2, Section 30(d) of the Rules, a proposed Protective Order, attached hereto, with the appropriate form to be signed by parties who wish to use information that is designated, and approved by the Commission to be treated, as "confidential," including confidential information that is subsequently designated as "confidential" during the course of the above-captioned case.

Support for "Confidentiality" Designation

The confidential testimony and workpapers of Company witness Joelle R. Steward, the confidential testimony of Rick A. Vail, and exhibits and workpapers of Rick T. Link contain confidential information, including pricing, contracts, reports, and other terms that could be misappropriated by parties for their commercial benefit and to the Company's and its customers' detriment if not treated as confidential under to the Commission's protective order. The exhibits also include confidential customer load information that is highly sensitive and cannot be publicly released and the Company's estimated regulatory compliance costs associated with the Ozone Transport Rule, which if publicly released would place the Company at a commercial disadvantage in future compliance proceedings and market transactions.

Accordingly, the Company has designated portions of each of the above designated testimony, exhibits, and workpapers as "confidential" and respectfully requests that the Commission approve that designation.

WHEREFORE, Rocky Mountain Power respectfully requests the following:

1. That the Commission approve Rocky Mountain Power's Petition.
2. That the Commission designate the indicated portions of the testimony, exhibits and workpapers as "confidential" and provide that such confidential information must be used in compliance with the protective order.
3. That the Commission issue a protective order in substantially the same form as the proposed protective order attached hereto.

DATED this 6th day of February, 2023.

Respectfully submitted,

ROCKY MOUNTAIN POWER

____

John Hutchings

Attorney for Rocky Mountain Power

WYOMING PUBLIC SERVICE COMMISSION

<table>
<tr>
<td>IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A WAIVER OF THE NON-SITUS CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR GATEWAY SEGMENT H, THE BOARDMAN TO HEMINGWAY TRANSMISSION PROJECT</td>
<td>Docket No. 20000-___-EN-23
(Record No. ______)

PROTECTIVE ORDER</td>
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PROTECTIVE ORDER

(Issued February __, 2023)

This matter is before the Wyoming Public Service Commission ("Commission") upon Rocky Mountain Power's (or the "Company") *Petition for Confidential Treatment and Protective Order* ("*Petition*") in the above-captioned matter. The Commission, having reviewed the *Petition*, Rocky Mountain Power's application, its files regarding Rocky Mountain Power, applicable Wyoming utility law, and otherwise being fully advised in the premises, FINDS and CONCLUDES:

1. Rocky Mountain Power is a public utility as defined by W.S. § 37-1-101(a)(vi)(C) and, as such, is subject to the Commission's jurisdiction under W.S. § 37-2-112.

2. On February __, 2023, Rocky Mountain filed a Petition for Confidential Treatment and Protective Order, in support whereof it alleged that certain testimony, exhibits, and workpapers in this matter contain confidential information and that parties to this matter might, during discovery, seek the production of trade secrets, commercially sensitive or confidential business information, or information that is otherwise so sensitive in nature that disclosure would jeopardize the interests of the party that has been requested to disclose the information, and the unlimited disclosure of which could result in economic harm to the disclosing party. The Company also asserted that a protective order would facilitate a full and timely review of the above-captioned application.

3. Rocky Mountain's *Petition* was heard by the Commission pursuant to due notice at its open meeting of February __, 2023. Commission Advisory Staff recommended the Commission approve Rocky Mountain's *Petition* as being generally compliant with Chapter 2, Section 30 of the Commission's Rules. We find there exists a potential body of information which is of such a sensitive nature that its unlimited disclosure could result in economic harm to Rocky Mountain

Power or another disclosing party but which should be shared with the parties to this proceeding. The Commission finds and concludes that Rocky Mountain Power has supported its request for confidential treatment of such documents and information under Rule Chapter 2, Section 30. The Commission also finds and concludes that the proposed documents offered by Rocky Mountain Power, suitably expressing the Commission's prerogatives in the matter and ensuring the necessary references to Rule Chapter 2, Section 30 of the Commission's Rules, should be approved in the public interest as a useful and efficient method of dealing with confidential information in this case. The Commission finds that sufficient grounds exist for entry of a protective order as required by Chapter 2, Section 30 of the Commission's Rules, generally as sought by Rocky Mountain in its *Petition*.

IT IS THEREFORE ORDERED THAT:

1. Pursuant to open meeting action taken on February __, 2023, Rocky Mountain Power's *Petition for Confidential Treatment and Protective Order* is granted.

2. The confidential information in this proceeding shall be dealt with according to the terms of the ensuing paragraphs 3 through 16.

3. The parties to this proceeding shall allow each of the authorized parties, under Chapter 2, Section 30 of the Commission's Rules and the terms of this *Protective Order*, to have access to and to review data and information claimed by each to be of a confidential nature. The parties have designated or may in the future designate documents filed with the Commission or produced in discovery as confidential for the reason that such documents contain confidential information, trade secrets, proprietary information or commercially sensitive information.

4. Definitions. For purposes of this *Protective Order*, the following terms shall mean:

a. "Documents" shall mean and include all written, recorded or electronic graphic matters of any kind or nature whatsoever, within the meaning of Rule 34(a) W.R.C.P., or Rule 1001 W.R.E., and shall extend to any subsequent compilation, summary, quotation, or reproduction thereof prepared at any subsequent time in any subsequent form or proceeding, in whole or in part and shall include computer software, computer models and information generated by computer software and models. The reference to "Rule 1001 W.R.E." is for definitional purposes only and is not intended to suggest that the Wyoming Rules of Evidence are applicable to Commission proceedings. Further the reference to W.R.C.P. is not intended to suggest that any of the Wyoming Rules of Civil Procedure are applicable to Commission proceedings, except those specifically made applicable to Commission proceedings by the Wyoming Administrative Procedure Act.

b. "Confidential Information" shall mean and include any Documents and all contents thereof which are marked "CONFIDENTIAL" by the party producing the information ("Producing Party"), including information prepared, presented, typed or copied on yellow paper.

c. "Authorized Person(s)" shall mean and be limited to the employees, attorneys and expert witnesses or consultants of the party receiving the information ("Receiving Party") who are necessary to assist counsel in preparation for the proceedings in this docket. "Authorized Person(s)" shall not include individuals responsible for marketing or other competitive activities or who could use the information in the normal course of their employment to the competitive disadvantage of the Producing Party except upon prior approval of the Commission. No person, with the exception of the Commissioners, members of the Commission Staff and the Wyoming Office of Consumer Advocate, shall be considered an Authorized Person under this *Protective Order* unless such person is qualified as such under paragraph 5 below.

d. "Authorized Use" shall mean and be limited to use only for purposes of this docket in addressing the issues arising in this proceeding over which the Commission has jurisdiction.

e. "Disclose", "make disclosure of", or "disclosure" shall mean and include the dissemination to any person, firm, corporation or other entity of the contents of a Document, whether that dissemination is by means of the transmittal or transfer of the original or a copy of that document or any verbal or other dissemination of the contents of the Document.

5. Restrictions on Disclosure of Confidential Information. All Confidential Information and the disclosure thereof shall be subject to the following restrictions:

a. A Producing Party or Receiving Party may submit Confidential Information to the Commission, the Commission Staff, and the staff of the Wyoming Office of Consumer Advocate for the purposes of this proceeding, provided that the information is submitted, identified and maintained as Confidential Information subject to Chapter 2, Section 30 of the Commission's Rules. Other than the disclosures described in the previous sentence, the Receiving Party shall not disclose any Confidential Information to anyone other than its Authorized Person(s) for the sole purpose of the Receiving Party's review and analysis of this filing.

b. Whether Confidential Information has been produced in hard copy or in some other form, the Receiving Party shall make no copies or reproductions of any kind or nature whatsoever of the Confidential Information so supplied, except that copies or reproductions may be made when necessary for use by Authorized Persons in preparation for the proceedings on the filing or the presentation of the party's case.

c. The foregoing notwithstanding and with the exception of the Commission, Commission Staff, or the staff of the Wyoming Office of Consumer Advocate, the Receiving Party may not receive Confidential Information until they have signed a Nondisclosure Agreement in the form attached hereto, marked as "Exhibit A" and incorporated herein by reference. Upon execution of "Exhibit A", the signed originals shall be furnished to counsel of record for the Producing Party and copies thereof shall be filed with the Commission. Furthermore, a Receiving Party may not disclose Confidential Information to an Authorized Person unless, prior to the disclosure of such Confidential Information, the Authorized Person has signed and furnished an "Exhibit A" Nondisclosure Agreement as required above.

d. Counsel for the Receiving Party shall be responsible for designating Authorized Persons to whom disclosure of Confidential Information is deemed necessary to assist counsel in the preparation for proceedings in this docket. The names of authorized persons shall be provided to the Producing Party at least five (5) business days prior to any disclosure to enable the Producing Party to challenge the right of an individual to review Confidential Information for any reason prior to disclosure to that individual, unless the Producing Party waives this right. In the event the Parties cannot resolve a challenge between themselves, the challenge will be resolved by the Commission. During the pendency of the challenge, no disclosure shall be made to the individual in question and the Commission shall retain its specific authority to extend or adjust deadlines as, in its opinion, justice may require due to delays caused by the exercise of rights under this provision or otherwise.

6. Protective measures for Highly Sensitive Confidential Information. A Producing Party may claim that additional protective measures, beyond those otherwise required under this *Protective Order*, are warranted for certain Confidential Information referred to as Highly Sensitive Confidential Information. A Producing Party making such a claim shall identify such Highly Sensitive Confidential Information and shall inform the Receiving Party of their claimed highly sensitive nature as soon as possible.

a. General procedure. As to documents designated as Highly Sensitive Confidential Information, the Producing Party shall have the right, at its option, not to provide copies thereof to other parties, their counsel, experts or other representatives. In the event a Producing Party does not provide copies of Highly Sensitive Confidential Information, such Highly Sensitive Confidential Information, if discoverable, may be made available for inspection and review by counsel or experts for the Receiving Party at a mutually agreed upon place and time. Inspection may occur at all times during normal business hours upon request made not later than fifteen (15) business days before inspection is to occur, and within such time as is allowed by the Commission under its Rules or the Wyoming Rules of Civil Procedure applicable to responses to discovery requests under the Wyoming Administrative Procedure Act. Failure of the Producing Party to make information available for inspection at the agreed place after timely request has been made shall constitute a waiver of the restrictions contained in this subparagraph and the Receiving Party may demand and shall be provided a copy of the information, subject to Chapter 2, Section 30 of the Commission's Rules and the other terms of this *Protective Order*. Where copies are not provided, counsel and experts reviewing the Highly Sensitive Confidential Information may make notes regarding the highly sensitive Confidential Information for reference purposes only. Such notes shall not consist of a verbatim or substantive transcript of the highly sensitive Confidential Information and shall be themselves Confidential Information subject to Chapter 2, Section 30 of the Commission's Rules and the terms of this *Protective Order*.

b. Additional protection. In the event that any party believes a different level of protection than that provided for above in this paragraph is appropriate for any Highly Sensitive Confidential Information, the parties shall first attempt to reach agreement on the appropriate level of protection. If agreement cannot be reached, any party may request that the Commission resolve the disagreement. The concerned party may petition the Commission for an order granting additional protective measures which the petitioner believes are warranted for the claimed Highly Sensitive Confidential Information that is to be produced. The petition shall set forth the particular basis for: the claim, the specific additional protective measures requested, the need therefore, and the reasonableness of the requested additional protection. A party who would otherwise receive the documents and information under the terms of this *Protective Order* may respond to the petition and oppose or propose alternative protective measures to those requested by the provider of the claimed Highly Sensitive Confidential Information. In disputes brought to the Commission for resolution under this subparagraph, the petitioning party shall have the burden to prove that the additional protections it proposes should be approved.

7. Disputes in general. In the event the Receiving Party objects to the Producing Party's designation of a document or its contents as Confidential Information, the materials shall be treated as Confidential Information until a contrary ruling by the Commission, or, if appropriate, a court of competent jurisdiction. Prior to the time any objection to a designation of Confidential Information is brought before the Commission or, if appropriate, a court of competent jurisdiction, for resolution, the parties shall attempt to resolve the objection by agreement. If the parties are unable to reach an agreement, then either of them may bring the objection before the Commission or, if appropriate, a court of competent jurisdiction in accordance with the applicable rules of that forum. In disputes brought to the Commission for resolution under this paragraph, the Producing Party shall have the burden under Chapter 2, Section 30 of the Commission's Rules to prove that the protections it proposes should be approved. The parties recognize that the Commission has the

authority to extend or adjust deadlines as, in its opinion, justice may require due to delays caused by the exercise of rights under this provision or otherwise. For purposes of resolving disputes concerning Highly Sensitive Confidential Information, references in this paragraph to Confidential Information shall include Highly Sensitive Confidential Information. All resolutions shall be made by order of the Commission.

8. <u>General procedures for the use of Confidential Information</u>.

a. <u>Receipt into Evidence</u>. Confidential Information may be received into evidence in this proceeding under seal. Unless the Commission requires or allows a different time period, at least ten (10) days prior to the use of, or substantive reference to any Confidential Information as evidence, the party intending to use such Confidential Information shall provide notice of that intention to the counsel for the Producing Party. The Requesting Party and the Producing Party shall make a good faith effort to reach an agreement so that the information can be used in a manner which will not reveal Confidential Information. If such efforts fail, the concerned parties shall within five (5) days, unless the Commission requires or allows a different time period, designate which portions, if any, of the documents to be offered, or referred to on the record contain Confidential Information. The portions of the documents so designated shall be placed in the sealed record. Only one (1) copy of documents designated by the Producing Party to be placed in the sealed record shall be made and only for that purpose. Any required additional copies of the record shall receive the same treatment. Otherwise, parties shall make only general references to Confidential Information in these proceedings, except as may be provided for in subparagraph c below. Notwithstanding the foregoing, the Commission may make and retain such copies of this Confidential Information as it sees fit for the efficient disposition of the proceeding.

b. <u>Seal</u>. While in the custody of the Commission or any member of its staff, these materials shall be marked "CONFIDENTIAL-SUBJECT TO PROTECTIVE ORDER IN DOCKET NO. 20000-________", and shall be immediately entitled to be treated as Confidential Information under Chapter 2, Section 30 of the Commission's Rules, pending any further order of the Commission.

c. <u>*In Camera* Hearing</u>. Any Confidential Information which must be orally disclosed by any person shall be part of the sealed record in this proceeding and shall be offered only in an *in camera* hearing, attended only by persons authorized to have access to the Confidential Information under Chapter 2, Section 30 of the Commission's rules and this *Protective Order*. Similarly, cross-examination on, or substantive references to, Confidential Information, as well as that portion of the record containing references thereto, shall be marked and treated as provided herein.

d. Appeal. Sealed portions of the record in this proceeding may be forwarded to any court of competent jurisdiction on appeal in accordance with applicable rules and regulations, but under seal as designated herein, for the information and use of the court only.

e. Return. Unless otherwise ordered, Confidential Information, including transcripts of any depositions to which a claim of confidentiality is made, shall remain under seal, shall continue to be subject to the protection of Chapter 2, Section 30 of the Commission's Rules and the requirements of this *Protective Order*, and shall, within 30 days after final settlement, or other conclusion of this matter, including any administrative or judicial review thereof, be either [i] returned to counsel for the Producing Party or [ii] destroyed by the Receiving Party. Compliance with this paragraph shall be evidenced by an affidavit of counsel for the Receiving Party in the form attached hereto as Exhibit B. The Commission may retain such Confidential Information as it deems necessary subject to Chapter 2, Section 30 of its Rules. Counsel who are provided access to Confidential Information pursuant to the terms of this *Protective Order* may retain their notes, work papers or other documents that would be considered the attorneys' work product created with respect to their use and access to Confidential Information in this docket. An expert witness, accorded access to Confidential Information pursuant to this *Protective Order*, shall provide to counsel for the party on whose behalf the expert was retained or employed, the expert's notes, work papers or other documents pertaining or relating to any Confidential Information. Counsel shall retain these expert's documents with counsel's documents.

f. Redacted public versions of Confidential Information. It is the Commission's policy that its proceedings be as open and transparent as possible, so members of the public may have the greatest possible access to and understanding thereof. Therefore, whenever only a portion of a Document is considered Confidential Information hereunder, the confidential portion shall be clearly identified and treated as such in accordance with this *Protective Order*. However, the Producing Party shall restrict its designation of confidential status to the end that as much of the Document as possible shall remain nonconfidential and open to public inspection. When a Producing Party submits such a partially confidential Document, it shall simultaneously submit a redacted version thereof with the Confidential Information blacked out or otherwise rendered indecipherable. The identification of Confidential Information in any partially confidential Document shall be restricted to those portions thereof which are actually confidential (e.g., if only two pages of a Document contain Confidential Information, only those pages should be reproduced on yellow paper). The public redacted version of any such document shall be clearly marked on its face "Redacted Nonconfidential Public Version".

9. Use by Parties. Where reference to Confidential Information in the sealed record is required in pleadings, cross-examinations, briefs, argument, motions or otherwise, it shall be, to the extent possible, only by citation or title, or exhibit number, or by some other non-confidential

description. Any other use of, or substantive references to, Confidential Information, shall be placed in a separate section of the pleading or brief and submitted to the Commission under seal, on yellow paper, and identified as provided for in paragraph 8b above. This sealed section shall be served only on counsel of record (one copy each), who have signed a Nondisclosure Agreement (Exhibit A). All the protections afforded by this *Protective Order*, the Commission's Rules and its orders with respect thereto shall apply to materials prepared and distributed under this paragraph.

10. Use in Decisions and Orders. The Commission will attempt to refer to Confidential Information in only a general or conclusory manner and will avoid reproduction in any decision of Confidential Information to the greatest possible extent. If the Commission deems it necessary to discuss Confidential Information specifically, it will treat the Confidential Information in a manner consistent with the treatment of Confidential Information in paragraph 9 above.

11. Removal of confidential status.

a. Voluntary disclosure. Nothing in this *Protective Order* shall preclude a Producing Party from using or disclosing any of its own Confidential Information for any purpose or to any person. If any information for which Confidential Information status is sought in this case has been previously filed by a party as public information with a court or any federal or state agency, the party seeking to have the designation continue to apply thereto shall petition the Commission for such a designation.

b. Petition for removal of confidential status. Any party at any time upon ten (10) days prior notice may seek by appropriate pleading to the Commission to have documents that have been designated as Confidential Information or Highly Sensitive Confidential Information, or which were accepted into the sealed record in accordance with this *Protective Order*, removed from the protective requirements of this *Protective Order*, or from the sealed record and placed in the public record. If the confidential nature of such information is challenged, the Commission will resolve the issue in an *in camera* hearing at which only those persons duly authorized hereunder to have access to such Confidential Information or Highly Sensitive Confidential Information shall be present. If the Commission finds that no party would be prejudiced thereby and the case continues to proceed in an orderly manner, it may provide in such order that its decision will not take effect for a period of ten (10) days or such other time period as may be deemed advisable by the Commission to protect the rights of parties to seek further relief and to provide for the efficient and orderly conduct of the case.

12. Limitations. Nothing in this *Protective Order* shall prohibit or limit any party as to any objections it may otherwise have to the disclosure of any Confidential Information to which this *Protective Order* applies.

13. Filing of Discovery Requests and Responses. In dealing with Confidential Information, the parties are reminded of Chapter 2, Section 17 of the Commission's Rules regarding discovery-related filings which states:

> (a) The taking of depositions and discovery shall be in accordance with Wyoming Statute § 16-3-107(g).
>
> (b) Unless the hearing officer or adjudicative agency orders otherwise, parties shall not file discovery requests, answers, and deposition notices with the hearing officer or adjudicative agency.

14. Protection to survive after end of proceeding. The provisions of this *Protective Order*, insofar as they restrict the disclosure and use of Confidential Information governed by this *Protective Order*, shall, without the written agreement of the parties or further order of the Commission, or if appropriate, a court of competent jurisdiction, continue to be binding after the conclusion of the case.

15. Commission authority retained. This *Protective Order* does not diminish or limit the Commission's authority to deal with Confidential Information in this case under applicable Wyoming laws and rules, including, without limitation, Chapter 2, Section 30 of the Commission's Rules. Nothing in this *Protective Order* shall prevent a party from placing before the Commission its desire for relief with respect to any issue arising with regard to any information alleged to be covered by this *Protective Order*, including disputes arising in the event that information is not disclosed to a party under this *Protective Order*.

16. Commission jurisdiction not limited hereby. Nothing in this *Protective Order* shall be construed as limiting the Commission's jurisdiction in this case or the prerogatives of the Commission regarding the orderly governance and disposition of this case, the use and disposition of Confidential Information or its prerogatives to make and enter all orders it deems necessary in the public interest, giving careful regard to the interests of the parties and the commercially sensitive nature of the information involved.

17. This *Protective Order* is effective immediately.

MADE and ENTERED at Cheyenne, Wyoming, on February __, 2023.

WYOMING PUBLIC SERVICE COMMISSION

____

(SEAL)

Attest:

<u>EXHIBIT A TO PROTECTIVE ORDER</u>

NONDISCLOSURE AGREEMENT:

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A WAIVER OF THE NON-SITUS CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR GATEWAY SEGMENT H, THE BOARDMAN TO HEMINGWAY TRANSMISSION PROJECT**-** DOCKET NO. 20000-___-EN-23

I hereby agree that I have been furnished a copy of and have read and understand the *Protective Order* issued by the Wyoming Public Service Commission in Docket No. 20000-___-EN-23 with respect to the review and use of Confidential Information. I understand the *Protective Order* and the definition of Confidential Information contained herein, and agree to comply with the terms and conditions of the *Protective Order* with respect to all Confidential Information covered thereby. I also have read, understand and agree to be bound by and to comply with Chapter, Section 30 of the Commission's Rules, a copy of which is attached hereto.

____
Name

____
Employer or Firm

____
Business Address

____
Party With Whom Associated

____
Date

____
Signature

ATTACHMENT TO EXHIBIT A -- NONDISCLOSURE AGREEMENT:

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A WAIVER OF THE NON-SITUS CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR GATEWAY SEGMENT H, THE BOARDMAN TO HEMINGWAY TRANSMISSION PROJECT**-** DOCKET NO. 20000-___-EN-23

Commission Rule Chapter 2, Section 30: Confidentiality of Information.

(a) Upon petition, and for good cause shown, the Commission shall deem confidential any information filed with the Commission or in the custody of the Commission or staff which is shown to be of the nature described in Wyoming Statute § 16-4-203(a), (d) or (g). All information for which confidential treatment is requested shall be treated as confidential until the Commission rules whether, and to what extent, the information shall be given confidential treatment.

(b) Any person requesting confidential treatment of information (except as directed by the Commission in investigative and discovery matters) shall file a petition that includes the following information:

(i) The assigned docket, if applicable.

(ii) Title the filing as: Petition for Confidential Treatment of ___________________.

(iii) Numbered listings and explanations in adequate detail to support why confidentiality should be authorized for each item, category, page, document or testimony. Each item, category or page of proposed confidential information shall be attached to the Petition and numbered in the right hand margin so that numbering corresponds with the numbering and detailed explanation(s) in the Petition. If only part of a page, or intermittent parts of pages, are requested to be kept confidential, these should be set off by brackets identified with an item number or numbers. Each page containing information for which confidential treatment is requested shall be printed on yellow paper and marked or stamped at the top in capital letters: CONFIDENTIAL INFORMATION.

(iv) A request for return or other final disposition of the information.

(c) All information deemed confidential under this Rule shall be retained in secure areas of the Commission's offices.

(d) If the person petitioning for confidential treatment of information intends that parties in a case have access thereto, upon signing a statement that the information shall be treated as confidential, the petitioner shall prepare a proposed protective order for the Commission's approval with an attached form to be signed by the parties and made part of the Commission's permanent case file.

(e) Information in the Commission's confidential files shall be retained for the period determined by the Commission. On an appeal of a Commission final order, any confidential information included in the record shall be sealed and delivered to the court pursuant to the W.A.P.A.

(f) The Commission may consider oral petitions for confidential treatment of information when the public interest requires.

EXHIBIT B TO PROTECTIVE ORDER

AFFIDAVIT OF COUNSEL:

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A WAIVER OF THE NON-SITUS CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR GATEWAY SEGMENT H, THE BOARDMAN TO HEMINGWAY TRANSMISSION PROJECT- DOCKET NO. 20000-___-EN-23

[Counsel] being of lawful age and being first duly sworn, hereby deposes and says that:

Alternative ¶1 (to be used if documents returned). I have obtained the original copies of all Confidential Information provided to [Receiving Party] by [Producing Party] in the Wyoming Public Service Commission's proceedings in **Docket No. 20000-___-EN-23** concerning Rocky Mountain Power and all such documents are being returned to [Producing Party] together with this Affidavit. Furthermore, I have obtained all copies and reproductions of such Confidential Information known to me to exist in the custody or control of [Receiving Party], its employees, attorneys, experts, consultants and agents and all such documents are being returned to [Producing Party] together with this Affidavit.

Alternative ¶1 (to be used if documents destroyed). I have obtained the original copies of all Confidential Information provided to [Receiving Party] by [Producing Party] in the Wyoming Public Service Commission's proceedings in **Docket No. 20000-___-EN-23** concerning Rocky Mountain Power and all such documents have been destroyed. Furthermore, I have obtained all copies and reproductions of such Confidential Information known to me to exist in the custody or control of [Receiving Party], its employees, attorneys, experts, consultants and agents and all such documents have been destroyed.

2. I have made diligent inquiry of all persons known to me to have had access to the Confidential Information received from [Producing Party] in the captioned proceeding and have otherwise diligently endeavored to identify and locate all copies of such Confidential Information in the custody or control of [Receiving Party], its employees, attorneys, experts, consultants and agents. Other than myself, the employees' attorney, experts, consultants, and agents who have had access to the Confidential Information together with their current address are listed below.

[LIST PERSONS WHO HAVE HAD ACCESS.]

Alternative ¶3 (to be used if documents returned). I am not aware of the existence of any copies or reproductions of the Confidential Information provided to [Receiving Party] by

[Producing Party] in the captioned proceeding that are not included and returned to [Producing Party] with this Affidavit.

Alternative ¶3 (to be used if documents destroyed). I am not aware of the existence of any copies or reproductions of the Confidential Information provided to [Receiving Party] by [Producing Party] in the captioned proceeding that have not been destroyed.

Further Affiant Sayeth Not.

DATED this _____ day of ________________, __________

____

Counsel for [Receiving Party]

STATE OF __________________)
)SS
COUNTY OF __________________)

The foregoing was acknowledged before me by _____________ on this ____ day of _______________, _________. Witness my hand and official seal.

____
Notary Public
My commission expires:____________________________

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BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
ROCKY MOUNTAIN POWER FOR A WAIVER	)	Docket No. 20000-___-EN-23
OF THE NON-SITUS CERTIFICATE OF PUBLIC	)	(Record No. ______)
CONVENIENCE AND NECESSITY FOR	)	
GATEWAY SEGMENT H, THE BOARDMAN TO	)	
HEMINGWAY TRANSMISSION PROJECT	)	

PacifiCorp, d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company") respectfully submits this Application to the Wyoming Public Service Commission ("Commission") under Wyo. Stat. § 37-2-205.1, and Commission Rule Chapter 3, Section 21(a). Rocky Mountain Power requests an order waiving the non-situs certificate of public convenience and necessity ("CPCN") for Energy Gateway Segment H, the Boardman-to-Hemingway 500-kilovolt ("kV") transmission line ("B2H" or the "Project"). The Company also requests waiver of the advanced review process set forth in the stipulation approved in Docket No. 20000-384-ER-10, Record No. 12702 ("Advanced Review Process"), which applies to non-situs segments of the Energy Gateway Transmission Project.[1] In the alternative, if the Commission denies Rocky Mountain Power's request for waivers, the Company provides in this Application the required information for issuance of a non-situs CPCN and approval under the Advanced Review Process. The Company has provided the required Notice of the Project to the Commission.[2]

B2H is a critical regional transmission line that will run approximately 300 miles from Boardman, Oregon southeast to the existing Hemingway substation in Owyhee County in southwest Idaho. The Company has partnered with Idaho Power Company ("IPC") and the Bonneville Power Administration ("BPA") to develop the Project. IPC is the overall project manager, responsible for B2H permitting, design, procurement, and construction. IPC will fund and own 45.45 percent of B2H and the Company will fund and own 54.55 percent of B2H.

B2H is reasonable and in the public interest. The Project is necessary to enable lower-cost and more reliable transmission service for the Company's growing customer load and to avoid acquisition of higher-cost generation and transmission resources. The Project is expected to result in risk-adjusted cost savings of approximately $1.7 billion, assuming medium natural gas prices and carbon dioxide ("CO_2") costs. There are three principal factors that produce these significant customer benefits.

[1] *In The Matter Of The Application Of Rocky Mountain Power For Approval Of A General Rate Increase In Its Retail Electric Utility Service Rates In Wyoming Of $ 97.9 Million Per Annum Or An Average Overall Increase Of 17.3 Percent,* 20000-384-ER-10, Record No. 12702 (Sept. 2011) [hereinafter "2010 Stipulation"]. At the time, the Commission relied on Wyoming's innovative ratemaking statute, Wyo. Stat. 37-1-121, to authorize the Advanced Review Process for out-of-state projects; Wyo. Stat. 37-2-205.1 now expressly authorizes Wyoming Commission review of non-situs projects.

[2] Commission Rule Chapter 3, Section 21(b).

First, B2H increases the ability to move resources across and between both PacifiCorp balancing authority areas ("BAA"). There currently is only one 500-kV transmission line connecting the Company's eastern BAA, PacifiCorp East ("PACE"), and its western BAA, PacifiCorp West ("PACW"). The Project will allow the Company to export 818 megawatts ("MW") of additional generation capacity from Wyoming, Utah, and Idaho generators to Oregon, Washington, and California customers. Increasing connections between BAAs will allow more efficient service in both areas using the most cost-effective generation available. Additionally, construction of B2H will provide regional benefits by strengthening the interconnected transmission grid in the West and enhancing resource adequacy.

Second, B2H enables lower-cost and more reliable transmission service to the Company's growing central Oregon loads. By constructing B2H and consolidating certain transmission rights with BPA (as part of the B2H transaction), the Company can avoid constructing significant generation resources in southern Oregon that would otherwise be required absent B2H.

Third, B2H reduces transmission service costs to the Company's increasing loads in the vicinity of BPA's planned Longhorn substation, which is the western terminus of B2H. B2H enables the Company to avoid significant third-party transmission expenses that would otherwise be required to serve this retail customer load.

The Company's request for waivers is based on the unique facts and circumstances of this case and Commission Rules Chapter 3, Section 21(a)(iii)(B), which allows the Commission to issue a waiver if it is in the public interest because there is: (1) a clear emergency; (2) a time-limited commercial or technical opportunity that provides value to or serves a public purpose or customer need of the affected public utility; or (3) any other factor that makes waiving the requirement in the public interest. Here, the Commission should waive the non-situs CPCN and Advanced Review approval because: (1) construction of the B2H line is in the public interest; (2) there is a time-limited window to maximize the customer benefits of the Project by placing it in-service in 2026, which requires completing the underlying transactions and obtaining regulatory approvals to allow construction to proceed as scheduled in July 2023; and (3) waiving the non-situs CPCN requirement and the Advanced Review Process for B2H will not harm Wyoming customers. The Company requests a Commission determination on the requested non-situs CPCN and Advanced Review waivers within 20 business days following the receipt of the Company's Application.[3]

Alternatively, if the Commission denies the requested waivers, the Company has included in this Application the required information for a non-situs CPCN and the Advanced Review Process. The Company requests issuance of a final non-situs CPCN and Advanced Review approval by June 30, 2023, to allow IPC to commence construction in July 2023.

I. NAME AND ADDRESS OF APPLICANT

1. PacifiCorp provides retail electric service under the name Rocky Mountain Power in the states of Wyoming, Utah, and Idaho, and under the name Pacific Power in the states of Oregon, Washington, and California. Rocky Mountain Power is a public utility in the state of Wyoming subject to the jurisdiction of the Commission. Rocky Mountain Power's principal place of business in Wyoming is 2840 East Yellowstone Highway, Casper, Wyoming 82602.

[3] *See* Commission Rule Chapter 3, Section 21(a)(ii) ("The Commission shall inform the utility whether or not the proposed facility or project is exempt [from the non-situs CPCN requirement] within 20 business days following receipt of the utility's notice[.]").

2. Formal correspondence and requests for additional information regarding this matter should be addressed to:

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon 97232

With copies to: Stacy Splittstoesser
Wyoming Regulatory Affairs Manager
Rocky Mountain Power
315 West 27th Street
Cheyenne, Wyoming 82001
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Informal inquiries related to this Application should be directed to Stacy Splittstoesser, Wyoming Regulatory Affairs Manager, at (307) 632-2677.

II. SUPPORTING TESTIMONY

Rocky Mountain Power's filing consists of a notice and request for waivers of the non-situs CPCN and Advanced Review requirements and detailed information explaining how the Project qualifies for these waivers. Also included is an alternative Application for a non-situs

CPCN and Advanced Review for the Project. The Application is supported by pre-filed written direct testimony and exhibits of the following Company witnesses:

- **Ms. Joelle R. Steward,** Senior Vice President of Regulation and Customer/Community Solutions for PacifiCorp, provides an overview of the Company's filing and explains why the Company's request for waivers is in the public interest. Ms. Steward also addresses the estimated rate impact of the Project.
- **Mr. Rick T. Link,** Senior Vice President of Resource Planning, Procurement, and Optimization, provides the economic analysis demonstrating that the Project is beneficial to Wyoming customers, reasonable, and in the public interest. Mr. Link describes the customer benefits resulting from the timely construction of the Project, and explains the need for the Project. Mr. Link also describes the existing and future agreements between IPC, BPA, and the Company relating to the Project.
- **Mr. Rick A. Vail,** Vice President of Transmission, provides a detailed description of the Project and demonstrates that the Project is necessary to improve the reliability of the transmission system. Mr. Vail's testimony describes how the Project will increase both the interconnection capacity and the transfer capability between PACE and PACW. Finally, Mr. Vail explains the asset exchanges that will occur between the Company and IPC as a result of this Project.

III. OVERVIEW OF THE PROJECT

B2H is an approximately 300-mile-long, 500-kV transmission line that will extend from a proposed switching station near Boardman, Oregon to the existing Hemingway Substation located in Owyhee County, Idaho. Approximately 274 miles of the transmission line is located in five Oregon counties: Malheur, Baker, Union, Umatilla, and Morrow Counties. A 24-mile segment of the Project will be in Owyhee County in Idaho.

Because of the length of B2H, the transmission line will also include ten communication stations along the route. These communication stations will all be constructed within the right-of-way of the transmission line. B2H will also include the installation of the B2H Midline Series Capacitor Project and development of a remedial action scheme.[4]

The Project has long been recognized as an integral component of the Company's and the region's long-term transmission plan. NorthernGrid—a planning association aiming to facilitate regional transmission planning across the Pacific Northwest and Intermountain West—has repeatedly identified B2H as a regionally significant project in its biennial regional transmission plans.[5]

The initial B2H agreement among IPC, BPA and the Company was a Joint Permit Funding Agreement, executed January 12, 2012, and amended several times, to jointly support the regulatory processes associated with obtaining necessary permits and other project development work. On January 18, 2022, the parties executed a non-binding Term Sheet as the framework for future agreements, which is included as Exhibit 3.1 to the testimony of Mr. Link.

Prior to execution of the Term Sheet, BPA decided to transition out of its role as a joint permit funding coparticipant and to instead rely on B2H by taking transmission service from IPC to serve its customers, leaving only the Company and IPC as owners of B2H. As a result of BPA's decision to take transmission service from IPC, the Term Sheet stipulates that IPC

[4] Direct Testimony of Rick T. Link, Exhibit 3.1, Term Sheet at 17 [hereinafter "Term Sheet"].
[5] *See* NORTHERNGRID, *Regional Transmission Plan for the 2020-2021 NorthernGrid Planning Cycle* at 31 (Dec. 8, 2021) (available at https://www.northerngrid.net/private-media/documents/2020-2021_Regional_Transmission_Plan.pdf) (last visited Jan. 3, 2023).

will acquire BPA's B2H project capacity, which will increase IPC's B2H project ownership share to 45.45 percent.[6] Because IPC assumed the entirety of BPA's ownership interest in B2H, BPA's transition did not affect the Company's ownership interest. When B2H is completed, IPC and the Company will jointly own as tenants in common the transmission line and all associated facilities and equipment.[7] Per the Term Sheet, IPC is the project manager responsible for federal, state, and local permitting efforts and construction of the Project, except that BPA will be responsible for designing, procuring, and constructing the Longhorn substation and relocating and replacing an existing BPA 69-kV line.[8]

The Term Sheet summarizes the various agreements the B2H stakeholders have executed to-date and those they intend to implement in the future, which include the following:[9]

1. The Company and IPC will execute the B2H Project Joint Construction Funding Agreement which will include definitive terms and conditions by which the parties will jointly support and contribute funds for the procurement, construction, and commissioning of B2H, allowing for energization of the Project by the earliest in-service date needed by the parties;
2. IPC and the Company will fund a portion of the proposed Longhorn substation near Boardman, Oregon;[10]
3. As part of the asset exchanges discussed below, IPC and the Company may expand their existing Joint Ownership and Operating Agreement, as amended and restated

[6] Term Sheet at 24.
[7] Term Sheet at 26.
[8] Term Sheet at 25.
[9] Exhibit 1.1 to this Application is a list of agreements that must be executed to effectuate the Project.
[10] Term Sheet at 11.

August 22, 2019, to include ownership, operation and maintenance provisions associated with B2H and the revised capacity owned due to the exchanged assets;[11]

4. The Company and IPC will execute two additional construction agreements, the Midpoint 500/345-kV Transformer Project Construction Agreement and the Kinport – Midpoint 345-kV Series Capacitor Bank Project Construction Agreement, through which the companies will make necessary capital upgrades to exchanged assets.

Additionally, the Company and IPC have agreed to exchange several transmission assets as part of the agreement governing the joint-ownership of B2H. IPC has agreed to transfer to the Company a percentage of the assets that make up the existing 500-kV and 345-kV transmission lines between the Borah, Kinport, Adelaide, Midpoint and Hemingway substations.[12] The Company has agreed to transfer to IPC a percentage of the assets that make up a 345-kV transmission line connecting the Populus substation to the Four Corners substation.[13] Finally, the Company has agreed to transfer to IPC certain to-be-determined Goshen area transmission assets, which would allow IPC to provide transmission service to all BPA customers in southeast Idaho currently served by the Company.[14] The agreements implementing these asset exchanges will be completed consistent with the agreed-upon Term Sheet. The Company will seek all necessary regulatory approvals relating to disposition of the property subject to the asset exchanges.

IV. WAIVER REQUEST

The Commission's rules expressly allow for waiver of the non-situs CPCN requirement if the Commission determines "[a]ny . . . factor . . . makes waiving the requirement in the

[11] Term Sheet at 14.
[12] Term Sheet at 13-14.
[13] Term Sheet at 13.
[14] Term Sheet at 14.

public interest[.]"[15] Similarly, the Commission has waived other filing requirements like the Advanced Review Process when doing so is in the public interest.[16] In this case, the Commission should grant a waiver because: (1) construction of B2H is in the public interest; (2) there is a time-limited window for moving forward with B2H to maximize customer benefits; and (3) waiving the non-situs CPCN requirement and the Advanced Review Process will not harm Wyoming customers.

A. Construction of B2H Is in the Public Interest.

The Commission previously waived certain filing requirements for applications relating to non-situs facilities that were partially owned by a Wyoming utility after determining that the utility's proposed actions were in the public interest.[17] Similarly, the Commission should waive the requirements to obtain a non-situs CPCN and complete the Advanced Review Process because B2H is in the public interest.

The Project will improve grid reliability by providing better operational control of the backbone transmission system by interconnecting PACE and PACW on the PacifiCorp transmission system. As explained in the testimonies of Mr. Link and Mr. Vail, through B2H the Company will secure an additional 300 MW of west-to-east transmission capacity and an additional 818 MW of east-to-west transmission capacity, which will enable the Company to efficiently deploy new generating facilities and better utilize existing resources to meet

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[15] Commission Rule Chapter 3, Section 21(a)(iii)(B)(III).

[16] *See In re Application of MCIMetro Access Transmission Services LLC d/b/a Verizon Access Transmission Services for a Waiver of Commission Rule Subsections 503(c)(i) and 503(d)(ii)(C) Relating to Quality of Service Reporting*, Docket No. 70027-88-TA-10) (Record No. 12658), Order at ¶6 (Nov. 24, 2010) (waiving requirement of recording and reporting requirements for five years after determining that a waiver "is consistent with the public interest").

[17] *In re Application of PacifiCorp for Approval of the Proposed Sale of its Interest in the Skookumchuck Hydroelectric Plant and for EWG Determinations*, Docket No. 20000-EA-04-207 (Record No. 8904), Opinion at ¶9 (Apr. 27, 2004) (waiving requirement to file Form 4 and approving sale of the Skookumchuck Project after determining that it was in the public interest to transfer ownership to another entity).

anticipated resource needs. Moreover, the Project has long been recognized as an integral component of the Company's and the region's long-term transmission plan. The Company has partnered with IPC in a non-binding agreement to fund and own B2H to improve transmission service to customers in both utilities' service territories. BPA will also enter into wheeling agreements to deliver energy across IPC-owned equipment to BPA customers in eastern Idaho. The Company, IPC and BPA are moving forward with B2H at this time because current circumstances make it necessary and economic for their customers throughout the region.

In addition, B2H was included as a critical element of the preferred resource portfolio in the Company's 2021 Integrated Resource Plan ("IRP").[18] The Company's updated economic analysis included in Mr. Link's testimony explains that B2H enables lower-cost and more reliable transmission service to serve the Company's increasing retail customer load, particularly in central Oregon and near B2H's western terminus at the proposed Longhorn substation. In central Oregon, the Company must double its transmission rights from 340 MW to 680 MW to meet growing customer needs. B2H enables the Company to secure this capacity increase without any additional transmission upgrades. Moreover, after acquiring B2H the Company will reduce its BPA wheeling expenses by consolidating certain point-to-point ("PTP") reservations on BPA's system that are used to reach central Oregon loads. Without B2H, the Company would still need increased transmission into central Oregon and serving that load would require dispatchable generation in southern Oregon ranging from 725 MW to 1,450 MW to prevent impacts to other existing rated paths. Without B2H, ensuring this dispatchable generation would require substantial investment in generation and in battery storage. Under the Company's current inter-state cost allocation methodology, Wyoming

[18] The Company has filed this IRP with the Commission. *In re Filing of Rocky Mountain Power's Integrated Resource Plan (IRP) for 2021*, Docket No. 20000-603-EA-21 (Record No. 15935).

would be allocated a portion of the increased system generation and transmission costs the Company would incur without B2H. Therefore, by avoiding costs that Wyoming customers would otherwise pay, B2H provides direct benefits to Wyoming.

In the Longhorn area, customer load near the proposed western terminus of B2H is also growing substantially. Because of those customers' proximity to B2H, the Company can serve those customers via a connection to the B2H line. Without B2H, serving this growing load will require PTP transmission service from various other utilities in the region, the cost of which will be attributed to the Company's Wyoming retail customers as net power costs. The net power cost savings resulting from B2H provide additional benefits to Wyoming customers.

To evaluate the cost-effectiveness of B2H, the Company analyzed the change in expected revenue requirement between two resource portfolios—one with B2H and one without. To ensure a robust evaluation, the Company calculated the present value revenue requirement differential ("PVRR(d)") between the two portfolios under a range of future natural gas price and CO_2 policy assumptions ("price-policy scenarios"). B2H results in significant cost savings in *all scenarios* compared to a non-B2H portfolio. In the price-policy scenario that assumed medium natural gas and medium CO_2 prices, the portfolio with B2H is $1.713 billion lower cost, demonstrating the robust customer benefits resulting from B2H. As discussed above, these benefits accrue directly to Wyoming customers in the form of lower net power costs and avoided transmission and generation investments.

B. Waivers Are Appropriate Because, Due to the Complexity of B2H, There Is a Time-Limited Period Outside of the Company's Control in Which to Obtain Regulatory Reviews, Allow Timely Construction of B2H, and Maximize the Benefits of the Project.

While development of B2H has been ongoing for many years, the current structure of the B2H transaction between the Company and BPA was not finalized until December 2022.

Once finalized, the Company updated its economic analysis of the Project in January 2023 to affirm the decision to move forward with construction, pending receipt of the necessary regulatory approvals.

B2H will provide maximum customer benefits if it is in-service by 2026. To achieve the 2026 in-service date, IPC must begin construction by mid-2023. B2H, however, is a complex transaction that involves two public utilities (IPC and the Company) and a governmental agency (BPA), and numerous agreements need to be executed either between BPA and IPC; BPA and the Company; and IPC and the Company to effectuate the parties' goals.[19] Some of these agreements must be in place before construction may begin.[20] Although the stakeholders have agreed upon a framework for these agreements codified in the Term Sheet, the negotiation, execution, and implementation of these agreements will require substantial time and resources to complete.

In addition, the outstanding regulatory processes for B2H include:

1. Obtaining a site certificate from Oregon's Energy Facility Siting Council ("EFSC"), whose Need Standard for Non-Generating Facilities requires an applicant to "demonstrate[] the need for the facility."[21] EFSC issued the site certificate in 2022.[22] The site certificate is currently under review on appeal to the Oregon Supreme Court. Three intervening parties to the EFSC proceedings separately appealed the final order.[23] The Oregon Supreme Court must issue its ruling on these appeals by June 2023.[24]

2. Obtaining a CPCN from the Public Utility Commission of Oregon, which requires IPC to prove "the necessity, safety, practicability and justification in the public interest for

[19] *See generally* Term Sheet.
[20] *See, e.g.*, Term Sheet at 16 (discussing the B2H Construction Funding Agreement).
[21] Oregon Administrative Rules ("OAR") 345-023-0005.
[22] Energy Facility Siting Council, *In re Application for Site Certificate for the Boardman to Hemingway Transmission Line*, Final Order (Sept. 27, 2022) (available at https://www.oregon.gov/energy/facilities-safety/facilities/Facilities%20library/2022-09-27-Final-Order-on-ASC.pdf) (last visited Jan. 4, 2023).
[23] *See generally Stop B2H Coalition v. Oregon Department of Energy*, S069919 (petition for review filed Dec. 6, 2022); *Michael McAllister v. Oregon Department of Energy*, S069920 (petition for review filed Dec. 6, 2022); and *Irene Gilbert v. Oregon Department of Energy*, S069924 (petition for review filed Dec. 7, 2022).
[24] Oregon Revised Statute ("ORS") 469.403(6) (requiring the Oregon Supreme Court to render a decision on an appeal of a site certificate within six months of the filing of a petition for review).

the proposed transmission line."[25] IPC filed this CPCN in September 2022 in Docket No. PCN 5 and the Company intervened as a party in December 2022.[26] A final order in that docket is expected by June 30, 2023.[27]

3. Obtaining a CPCN from the Idaho Public Utilities Commission, which requires a finding that "the present or future public convenience and necessity require or will require" construction of the line.[28] IPC filed its CPCN application in January 2023 and requested a final order by June 30, 2023. The Company is also seeking a CPCN for the Project in Idaho and submitted its own application on January 27, 2023.

4. Obtaining local permits and approvals from the various municipalities and counties through which the Project is routed.

In addition to these regulatory filings, IPC must also procure the necessary materials and contractors to construct the Project. IPC stated in its application for a CPCN in Idaho that it anticipates issuing Requests for Proposals for materials and contractors during the first quarter of 2023 and selecting a construction manager in the second quarter of 2023.[29]

Finally, because BPA is a federal agency, BPA must comply with federal notice requirements before finalizing any agreements relating to B2H. On January 9, 2023, BPA issued its public notice via a Letter to the Region announcing BPA's completion of B2H project negotiations and releasing the customer engagement schedule, identifying dates for the comment period, customer workshop, and an expected final decision in March 2023.

There is a time-limited window for completing the outstanding agreements and obtaining regulatory approvals to allow construction to proceed as scheduled in July 2023, which is necessary to achieve B2H's planned 2026 in-service date. The Company was unable

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[25] ORS 758.015(2). Idaho Power has initiated the CPCN process in Oregon.
[26] *In re Idaho Power Company's Petition for Certificate of Public Convenience and Necessity*, Docket PCN 5, Initial Application (Sept. 30, 2022) (available at https://edocs.puc.state.or.us/efdocs/HAA/pcn5haa84035.pdf) (last visited Jan. 4, 2023); Docket PCN 5, PacifiCorp Petition to Intervene (Dec. 9, 2022) (available at https://edocs.puc.state.or.us/efdocs/HAP/pcn5hap15620.pdf) (last visited Jan. 4, 2023).
[27] *In re Idaho Power Company's Petition for Certificate of Public Convenience and Necessity*, Docket PCN 5, Administrative Law Judge Memorandum at 2 (Oct. 20, 2022) (available at https://edocs.puc.state.or.us/efdocs/HDA/pcn5hda15939.pdf) (last visited Dec. 28, 2022).
[28] Idaho Code Section 61-526.
[29] Case No. IPC-E-23-01, Application at 15 (Jan. 9, 2023).

to file this Application earlier because it first needed to finalize the terms of the transaction, update its economic analysis, and confirm the decision to move forward with the Project. Waiver of Wyoming's non-situs CPCN and Advanced Review Process requirements would significantly assist the Company and its B2H partners in meeting the challenging and time-sensitive milestones necessary to advance the Project.

Placing B2H in service by 2026 will maximize the customer benefits of the Project and allow the Company to secure the most cost-effective resources to serve growing customer load. Given the remaining regulatory and contractual proceedings that B2H stakeholders must complete before construction can begin, to ensure timely construction and Project completion, it is in the public interest to waive the requirements to obtain a non-situs CPCN and complete the Advanced Review Process.[30]

C. Waiver Will Not Harm Wyoming Customers.

Waiver is in the public interest when it will not harm Wyoming customers.[31] Waiver of the non-situs CPCN requirement and the Advanced Review Process for B2H will not negatively impact any Wyoming customers. Regardless of whether the Commission waives the requirement to obtain the non-situs CPCN and Advanced Review Process, customers' rates will not be affected by construction of B2H until after the Commission allows the Company to include the Project in its rate base in a future general rate case. Importantly, before the

[30] *See In re Amended Application of Rocky Mountain Power for Certificates of Public Convenience and Necessity and Nontraditional Ratemaking for Wind and Transmission Facilities*, Docket No. 20000-520-EA-17 (Record No. 14781), Letter Order (Apr. 17, 2019) (waiving notice requirement to allow construction of transmission line to begin immediately).

[31] *See, e.g.*, *In re Application of High West Energy for Authority to Waive the Tariff Requirement to Revise the Energy Cost Adjustment*, Docket No. 10015-CP-02-38 (Record No. 7240), Notice and Order at ¶9 (Mar. 1, 2002) ("The Commission finds and concludes that approval of the waiver of the tariff requirement to revise the energy cost adjustment will not harm customers and, therefore, is consistent with the public interest.").

Commission allows any change to the Company's rates, any party may still raise issues regarding the prudence of the Project or recovery of costs in the general rate case.

Not only will customers be able to raise concerns regarding the prudence of B2H in a subsequent rate case, but the purpose of the non-situs CPCN and Advanced Review Process will be thoroughly assessed in other regulatory proceedings.[32] According to the Wyoming Supreme Court, "[t]he purposes of requiring a certificate of convenience and necessity are to protect the public from speculation and duplication of facilities, and from inadequate service and higher rates which frequently result from such duplication, and to protect utilities from competition."[33] That purpose will be satisfied through the extensive permitting processes required in the two states where B2H will be located—Oregon and Idaho. As discussed above, the EFSC site certificate proceedings and the CPCN requirements in both Oregon and Idaho require substantial proof that B2H is not mere duplication of existing facilities and is, in fact, necessary to continue serving customers. When regulating transmission, the Commission is specifically authorized to "consider regional effects of its orders upon the utility and may consider requirements imposed upon the utility by the laws of other states within the region or the orders of other commissions within the region."[34]

In light of these statutory and regulatory requirements in the states where B2H will be located and the subsequent prudence review in Wyoming, customers will be protected from higher rates resulting from the duplication of facilities. Because the purpose of the non-situs CPCN and Advanced Review Process will be furthered in other regulatory proceedings, wavier

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[32] *See In re Application of Starlink Services, LLC for Designation as an Eligible Telecommunications Carrier*, Docket No. 60077-1-RA-21 (Record No. 15687), Order Granting Designation at ¶12 (June 4, 2021) (waiving requirement to file five-year plan because the governing FCC regulations will ensure satisfaction of the "purpose" of the Wyoming filing requirement).
[33] *Utah Power & Light Co. v. Wyo. Publ. Serv. Comm'n*, 713 P.2d 240, 243 (Wyo. 1986) (quoting 73B C.J.S. Public Utilities § 69(c) (1983)).
[34] Wyo. Stat. 37-2-122(b)(iii).

will not affect Wyoming rates, and customers can still challenge the prudency of B2H in a general rate case, waiver of the non-situs CPCN and Advanced Review Process requirements will not harm customers and therefore is in the public interest.

V. ALTERNATIVE APPLICATION FOR NON-SITUS CPCN AND ADVANCED REVIEW PROCESS

If the Commission rejects the Company's request for waivers, the Company alternatively requests that the Commission issue a non-situs CPCN for B2H and provide Advanced Review approval. The Company provides the following information to satisfy the requirements of Commission Rule Chapter 3, Section 21(i) to demonstrate compliance with the Commission's standards for issuance of a non-situs CPCN and the Advanced Review Process. The Company requests expedited review of this Application to allow a final order by June 30, 2023, so that construction of the Project may begin in July 2023.

A. Legal Standard for Non-Situs CPCN

Before constructing a transmission line located outside Wyoming, Wyo. Stat. § 37-2-205.1(a)-(b) requires a public utility to obtain a non-situs CPCN if the "non-situs resource is intended by the public utility to be a capital investment in a plant on which return is earned in Wyoming" and the "capital investment in the non-situs resource exceeds one percent (1%) of the total capital investment in the plant on which return is earned, that is assigned or allocated to Wyoming customers, based on the public utility's most recent general rate case determination." Here, the Project will be constructed outside Wyoming in Idaho and Oregon. The Company intends to include the Project in Wyoming rates and the capital investment would exceed one percent of the Company's Wyoming-allocated rate base.

To obtain a non-situs CPCN, an applicant must demonstrate that "the present or future need for the non-situs resource is prudent and in the public interest."[35] To the Company's knowledge, the Commission has not previously interpreted this standard in any written order.[36] However, the Commission has applied a related standard that governs issuance of situs CPCNs under Wyo. Stat. § 37-2-205—which similarly requires the Company to provide evidence of "the necessity of additional service in the community."[37]

In determining whether a project is necessary and in the public interest under Wyo. Stat. § 37-2-205, the Commission has often relied on the fact that the proposed resource was identified and supported in the utility's most recent IRP.[38] The Commission has approved situs CPCNs that are not strictly necessary for safe and reliable service to Wyoming customers when those facilities nonetheless serve the public interest.[39] The Commission has also determined that proposed facilities were necessary when those facilities were proposed to expand access to broader utility markets and reduce dependence on rates charged by other utilities.[40] The

[35] Wyo. Stat. §37-2-205.1(a).
[36] The Company has previously sought a waiver of the non-situs CPCN requirement for the Company's Pryor Mountain Wind Energy Facility, but the Commission determined that the statute did not apply because the Company had already begun construction of that facility prior to the effective date of Wyoming's non-situs CPCN statute. *In re the Application of Rocky Mountain Power for a Waiver of Non-Situs Certificate of Public Convenience and Necessity for Pryor Mountain Wind Energy Facility and Expedited Treatment*, Docket 20000-563-EN-19 (Record No. 15292), Opinion at ¶9 (Aug. 13, 2019). The Company is not aware of any other written orders applying Wyo. Stat. §37-2-205.1.
[37] Wyo. Stat. §37-2-205(c).
[38] *See, e.g.*, *In the Matter of the Application of Black Hills Power Inc. for a Certificate of Public Convenience and Necessity for Wygen III, a 100 MW Coal-Fired Generation Facility to be Located in Gillette, Wyoming*, Docket No. 20002-69-EA-07, Record No. 11549, Memorandum Opinion, Findings and Order, ¶ 44 (May 13, 2008); *In the Matter of the Application of Cheyenne Light, Fuel, and Power Co. for a Certificate of Public Convenience and Necessity for Wygen II, a 90 MW Coal-Fired Steam Electric Generating Plant*, Docket No. 20003-EA-05-82, Record No. 9902, Order Granting Application for a Certificate of Public Convenience and Necessity, ¶ 29 (August 19, 2005).
[39] *In re Application of SourceGas Distribution LLC for a Certificate of Public Convenience and Necessity for Major Facility Construction of the Chokecherry Compressor Station Located in Walcott, Wyoming, Approval of a Waiver of Section 249 of Commission's Rules, Authority to Implement a Revenue Adjustment Mechanism and to Issue New Tariffs*, Docket No. 30022-219-GA-13 (Record No. 13646), Opinion at ¶¶55, 58 (Aug. 14, 2014) ("The non-reliability-related project, which includes a compressor station and related facilities, is not necessary for safe and reliable service to Casper Division ratepayers. . . . [W]e find the non-reliability-related part of the CPCN serves the public interest.").
[40] *Williston Basin Interstate Pipeline Co. v. Wyoming Public Servs. Comm'n*, 996 P.2d 663, 669 (Wyo. 2000).

Commission considers the utility's previous experience constructing and operating similar plants when reviewing a CPCN application.[41]

Here, the testimonies of Ms. Steward and Messrs. Vail and Link demonstrate that the Project is necessary, prudent, and in the public interest. Ms. Steward outlines how B2H meets the Commission's non-situs CPCN requirements. Mr. Link demonstrates the Project's substantial customer benefits of approximately $1.7 billion compared to the generation and transmission facilities that would be necessary to serve customer load without B2H. Finally, Mr. Vail demonstrates the need for the Project to expand access to the Mid-Columbia market hub and to increase the Company's capacity to export electricity generated in its eastern BAA to customers in the western BAA. Mr. Vail further demonstrates that the Company has extensive experience constructing and operating similar facilities.

B. Non-Situs CPCN Application Information Requirements

Pursuant to Commission Rules Chapter 3, Section 21(c)(i) governing applications for non-situs CPCNs, the Company provides the following information:

Name and Address of the Applicant (Section 21(c)(i)(A)).

PacifiCorp d/b/a Rocky Mountain Power with an address at 1407 West North Temple, Salt Lake City, Utah 84116.

Type of Plant, Property, or Facility Proposed to be Constructed or Acquired (Section 21(c)(i)(B)).

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[41] *In the Matter of the Application of Black Hills Power Inc. for a Certificate of Public Convenience and Necessity for Wygen III, a 100 MW Coal-Fired Generation Facility to be Located in Gillette, Wyoming*, Docket No. 20002-69-EA-07, Record No. 11549, Memorandum Opinion, Findings and Order, ¶¶ 44, 46 (May 13, 2008) ("Wygen III benefits from BHP's extensive and successful past experience in constructing and operating similar plants;" proposed facility "will add value to Wyoming's natural resources and will offer distinct advantages to . . . customers and the economy . . . by providing a stable supply of electricity, increasing price stability and decreasing the exposure to the volatility of the wholesale electricity market.")

As described above, and in more detail in Mr. Vail's testimony, the Company proposes to construct the Gateway Segment H Boardman to Hemingway 500-kV transmission line.

The Project includes the following elements, which may include additional ancillary facilities as the engineering design plan becomes final:

1. An approximately 300-mile-long 500-kV electric transmission line crossing Owyhee County in Idaho and five Oregon counties: Malheur, Baker, Union, Umatilla, and Morrow Counties. The line consists of:
    a. Construction of approximately 271 miles of single-circuit 500-kV transmission line in Oregon;
    b. Construction of approximately 24 miles of single-circuit 500-kV transmission line in Idaho; and
    c. Removal of 12 miles of existing 69-kV transmission line;
2. A newly constructed switching station proposed to be constructed near Boardman, Oregon;
3. Ten communication stations constructed within the right-of-way of the transmission line;
4. Construction of the Midline Series Capacitor substation;
5. Construction of approximately 206 miles of new access roads; and
6. Substantial modification of approximately 223 miles of existing roads.

The Project also consists of the following exchange of assets between the Company and IPC:

1. Transfer from the Company to IPC of Populus-Four Corners assets, including a percentage of the assets that make up the 345-kV transmission lines between the following substations and assets to create a path through each substation: Four

Corners, Pinto, Huntington, Camp Williams, Mona, Terminal, 90th South, Ben Lomond and Populus;[42]

2. Transfer from IPC to the Company of Borah/Kinport to Hemingway and Midpoint to Borah/Kinport assets, including a percentage of the assets that make up 500-kV and 345-kV transmission lines between the following substations and assets to create a path through each substation: Borah, Kinport, Adelaide, Midpoint and Hemingway;[43]

3. Transfer from the Company to IPC of certain to-be-determined Goshen area transmission assets that would allow IPC to provide transmission service to all BPA customers in southeast Idaho currently served by the Company.[44]

Description of the Facilities Proposed to be Constructed or Acquired, Including Preliminary Engineering Specifications in Sufficient Detail to Properly Describe the Principal Systems and Components, and Final and Complete Engineering Specifications When They Become Available. ((Section 21(c)(i)(C)).

B2H is a high-voltage single-circuit 500-kV transmission line that will extend approximately 300 miles from central Oregon to southwestern Idaho. B2H will begin at the proposed Longhorn substation near Boardman, Oregon. From the proposed Longhorn substation, B2H begins heading south into north-central Morrow County before turning east through Umatilla County and into Union County. Beginning in Union County, B2H will head southeast through Baker County. In Malheur County the route briefly turns to the southwest before finally returning southeast and eventually terminating at the existing Hemingway substation in Owyhee County, Idaho.

[42] Term Sheet at 13.
[43] Term Sheet at 13-14.
[44] Term Sheet at 14.

After leaving the proposed Longhorn substation, the transmission line runs south for approximately 19 miles, paralleling existing transmission and pipeline rights-of-way for the first 13 of those miles. At that point, B2H turns east-by-southeast through Morrow and Umatilla Counties and enters Union County.

Beginning at approximately milepoint 90, B2H begins to parallel the corridor of Interstate 84 ("I-84") as it approaches the city of La Grande, Oregon. B2H roughly parallels I-84 for the next 110 miles through Union and Baker Counties.

Shortly after entering Malheur County, B2H turns south for approximately 12 miles primarily through land that is managed by the Bureau of Land Management ("BLM"). At approximately milepoint 212 the transmission line turns to the southwest through agricultural and BLM land for approximately 14 miles. Finally, the transmission line turns to the southeast and continues primarily through BLM-managed lands. At approximately milepoint 253, B2H enters the BLM's Vale District Utility Corridor, which the transmission line then follows for much of its remaining path through Malheur County as it approaches the Oregon-Idaho state line.

After crossing into Owyhee County, Idaho, the transmission line continues in a southeastern direction until finally terminating at the existing Hemingway substation.

Mr. Vail's testimony provides additional descriptions of the specific facilities that will be constructed.

The Rates, if any, Proposed to be Charged for the Service that will be Rendered Because of the Proposed Construction or Acquisition (Section 21(c)(i)(D)).

The Company is not seeking ratemaking treatment for B2H at this time, but Mr. Link's testimony includes a forecast of the change in nominal revenue requirement due to B2H. This forecast demonstrates a lower overall revenue requirement through the end of the study horizon in 2042. In addition, Ms. Steward's testimony provides the estimated rate impact and demonstrates that when B2H enters service in 2026, it will have a modest 1.95 percent impact on Wyoming retail rates based on current assumptions.

The Estimated Total Cost of the Proposed Construction or Acquisition (Section 21(c)(i)(E)).

Mr. Vail's testimony includes the Company's confidential estimate for its in-service cost of B2H.

The Manner by Which the Proposed Construction or Acquisition will be Financed (Section 21(c)(i)(F)).

The Company intends to finance the Project through its normal sources of capital, both internal and external, including net cash flow from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, capital contributions and other sources. Although the Project would be a significant investment on the part of the Company, the financial impact will not impair the Company's ability to continue to provide safe and reliable electricity service at reasonable rates.

Documentation of the Financial Condition of the Applicant (Section 21(c)(i)(G)).

Ms. Steward's testimony describes the Company's financial condition and explains that the Company has the financial ability to make these investments. The Company's current financial condition is also on file with the Commission as reflected in: 1) the Company financing activity reports submitted on a quarterly basis in Docket No. 20000-372-EA-10, 2) the annual reports submitted as required by Commission Rule Chapter 3, Section 32, 3) the semi-annual results of operations reports submitted in April and October, and 4) credit rating agency reports as they are issued as required by Docket No. 20000-EA-5-226.

Estimated Annual Operating Revenues and Expenses that are Expected to Accrue from the Proposed Construction or Acquisition, including a Comparison of the Overall Effect on the Applicant's Revenues and Expenses (Section 21(c)(i)(H)).

The estimated annual operating revenues and expenses are incorporated in the revenue requirement calculation discussed by Ms. Steward, which the Company will seek to be incorporated into retail rates in a future rate case.

Estimated Start and Completion Dates of the Proposed Construction or Date of Acquisition (Section 21(c)(i)(J)).

As project manager, IPC is primarily responsible for construction. IPC is expected to begin construction of the Project by July 1, 2023. The Company expects the Project to become commercially operational by 2026.

A Statement Setting Forth the Need for the Facility in Meeting Present or Future Demands for Service in Wyoming or Other States Within the Utility's Service Area (Section 21(c)(i)(K).

As described above and outlined in the direct testimony of Messrs. Vail and Link B2H is necessary to enable lower-cost and more reliable transmission service for the Company's growing customer load and to avoid acquisition of higher-cost generation and transmission resources.

C. Advanced Review Information Requirements

In Rocky Mountain Power's 2010 Wyoming general rate case ("2010 GRC"), the Commission approved a settlement that created the Advanced Review Process to allow review "generally before construction" of major segments of Energy Gateway.[45] Under the Advanced Review Process, the Company agreed to ask the Commission to "rule on whether the proposed construction of the transmission line is reasonable and in the public interest in advance of the

[45] 2010 Stipulation at ¶13(a)(i).

line being constructed."[46] Here, the Company's testimony demonstrates that B2H is reasonable and in the public interest because it will reduce overall customers costs by allowing for the avoidance of higher cost generation and transmission investments, reducing net power costs, and creating a more reliable and resilient backbone transmission grid.

In addition to the filing requirements found in the Commission's Rules Chapter 3, Section 21, the 2010 Stipulation also requires that the Company's Application include the following:

An Explanation of Whether the Proposed Construction of the Transmission Line Is Reasonable and in the Public Interest (2010 Stipulation ¶13(a)(ii)).

For the reasons discussed above in Section IV of this Application, B2H is reasonable and in the public interest. These reasons include: (1) construction of B2H is necessary to enable lower-cost and more reliable transmission service for the Company's growing customer load and to avoid acquisition of higher-cost generation and transmission resources; (2) B2H is the most cost-effective means of serving customers' growing load and is expected to result in cost savings of approximately $1.7 billion, assuming medium natural gas prices and CO_2 costs; and (3) B2H will increase grid reliability and resilience.

A Description of the Proposed Facilities (2010 Stipulation ¶13(a)(iii)(1)).

A description of the proposed facilities is set forth above.

An Estimate of the Cost to Construct the Proposed Facilities (2010 Stipulation ¶13(a)(iii)(2)).

Mr. Vail's testimony includes details on the cost of the Project.

A Detailed Analysis and Quantification of the Benefits of the Facilities Both to the Overall PacifiCorp System and to Wyoming Customers in Particular in Terms of Increased Reliability or Relatively Lower Net Power Costs, Increased Generation Alternatives and the Benefits of Generation Diversity (2010 Stipulation ¶13(a)(iii)(3)).

[46] 2010 Stipulation at ¶13(a)(ii).

In addition to the discussion above, the detailed analysis of the benefits of B2H is provided in the testimony of Mr. Link. In particular, B2H will provide greater east-to-west transfer capability, which will allow more efficient dispatch and greater transfers of energy from resources in PACE to serve customers in PACW. Moreover, the transmission investments, third-party transmission expense, and generation investments that would be required without B2H would have been allocated to customers across the Company's system, including Wyoming, in accordance with the terms of the current inter-state cost allocation methodology. Because B2H allows the Company to avoid costs that would have been borne by Wyoming customers, the expected savings discussed by Mr. Link provide direct benefits to Wyoming customers.

A Discussion of Alternatives to the Facilities Including but Not Limited to New Generation Sited More Proximate to Load (2010 Stipulation ¶13(a)(iii)(4)).

Mr. Link's testimony describes the alternative facilities that were analyzed in the 2021 IRP, the 2021 IRP Update, and the Company's updated modeling, all of which selected B2H as an integral component of the Company's preferred portfolio and identified the Project as the most cost-effective means of serving customers' growing load.

A Discussion of the Impact on Access to Renewable Generation Resources (2010 Stipulation ¶13(a)(iii)(5)).

As detailed in Mr. Vail's testimony, B2H will provide greater access to the Mid-Columbia energy hub, which will provide improved access to geographically diverse renewable generation.

A Discussion of the Proposed Allocation of the Cost of the Facilities between the Federal and State Jurisdictions (2010 Stipulation ¶13(a)(iii)(6)).

As described in greater detail in the testimony of Mr. Vail and Mr. Link, B2H will be considered a network transmission asset under the Company's Open Access Transmission

Tariff, and Federal Energy Regulatory Commission precedent for ratemaking supports rolling the costs of these assets into the Company's transmission rates. The testimony describes how, through inclusion in the Company's OATT, part of the costs of B2H will be recovered from third-party transmission customers and included as an offset to the benefit of retail customers. As discussed above, the Company will not include B2H in Wyoming rates until the Commission approves in a future rate case inclusion of the Project in the Company's rate base.

Description of Any Sage Grouse Habitat in the Vicinity of the Project (2010 Stipulation ¶13(a)(iii).

Mr. Vail's testimony describes the sage grouse habitat in the vicinity of B2H. Importantly, much of the sage grouse habitat is in Oregon. To obtain a site certificate from Oregon EFSC, IPC was required to demonstrate compliance with Oregon's Greater Sage-Grouse Conservation Strategy,[47] which sets population and habitat management objectives and advances sage-grouse population and habitat protection through a mitigation hierarchy and the establishment of a mitigation standard for impacts from certain types of development actions in sage-grouse habitat.[48] Oregon EFSC determined that IPC has demonstrated compliance with the Greater Sage-Grouse Conservation Strategy by minimizing impacts to sage grouse habitat to the extent possible and mitigating unavoidable impacts.[49] The site certificate for B2H further includes multiple conditions ensuring protection of sage grouse habitat.[50]

[47] OAR 345-022-0060(2).
[48] OAR 635-140-0000.
[49] *In re Application for Site Certificate for the Boardman to Hemingway Transmission Line*, Final Order at 401-02.
[50] *In re Application for Site Certificate for the Boardman to Hemingway Transmission Line*, Final Order, Attachment 1: Site Certificate at 53-55, 60, 65 (Sept. 27, 2022) (available at https://www.oregon.gov/energy/facilities-safety/facilities/Facilities%20library/2022-09-27-Attachment-1-Site-Certificate.pdf) (last visited Jan. 4, 2023).

VI. CONCLUSION

The Company requests that the Commission approve the request for waivers of the non-situs CPCN and Advanced Review Process requirements for B2H. This request is based on the fact that: (1) timely construction of the Project is in the public interest because B2H is necessary to enable lower-cost and more reliable transmission service for the Company's growing customer load and avoid acquisition of higher-cost generation and transmission resources; (2) there is a time-limited window for completing the underlying transactions and obtaining regulatory approvals to allow construction to proceed as scheduled July 2023, which is necessary to achieve B2H's planned 2026 in-service date and maximize the customer benefits of the Project; and (3) the waivers will not harm customers because prudence and cost recovery will still be determined and fully vetted in a future rate case, consistent with the Commission's historical treatment of situs CPCNs in Wyoming. The Company requests a Commission determination of the waivers within 20 business days of receiving this Application.

If the Commission does not approve the requested waivers, the Company requests the Commission approve a non-situs CPCN and issue an order affirming compliance with the Advanced Review Process based upon the information submitted in this Application. The Company has provided the information requirements for a non-situs CPCN and Advanced Review approval to streamline the application process and allow for expedited treatment and a decision no later than June 30, 2023.

Respectfully submitted this 6th day of February 2023.

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Attorney for Rocky Mountain Power

Rocky Mountain Power
Exhibit 1.1
Docket No. 20000-___-EN-23

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying the Application

B2H List of Agreements

February 2023

IDAHO POWER
Construction, Ownership, Operation, Asset Exchanges and Service Agreements Necessary for the Boardman to Hemingway Project

	Agreement	Term Sheet Identification	Parties	Description	Anticipated Execution
1	**Second Amended and Restated Boardman to Hemingway ("B2H") Transmission Project Joint Permit Funding Agreement**	§ 3(a)(14)	Idaho Power and PacifiCorp	The Amended and Restated Joint Permit Funding Agreement provides definitive terms and conditions by which Idaho Power, PacifiCorp and Bonneville Power Administration ("BPA") jointly support and contribute funds to the processes associated with obtaining necessary governmental authorizations and completing other necessary work to permit, site, and acquire Rights-of-Way for the B2H project. The second amendment recognizes the reallocation of the parties' permitting interest and related funding obligations following the transfer of BPA's permitting interest to Idaho Power. Upon execution, Idaho Power's permitting interest will increase to 45.45% and PacifiCorp's permitting interest remains at 54.55%.	Following BPA Public Process, March 2023 **VAIL**
2	**Network Integration Transmission Service Agreement ("NITSA") for Goshen Load**	§ 3(b)(1)	Idaho Power and BPA	This agreement will allow for Idaho Power to provide firm network transmission service to BPA's customers at Goshen. The term of the NITSA will be 20-years from energization of the B2H project, with a renewal or rollover option at BPA's discretion as required and permitted by the Federal Energy Regulatory Commission ("FERC"). BPA will pay Idaho Power's Network Transmission Service rates as established under Attachment H of the Company's Open Access Transmission Tariff ("OATT").	Following BPA Public Process, March 2023 **N/A**
3	**NITSA for Idaho Falls Load**	§ 3(b)(1)	Idaho Power and BPA	This NITSA will allow for Idaho Power to provide firm network transmission service to BPA's customers at Idaho Falls. The term of the NITSA will be 20-years from energization of the B2H project, with a renewal or rollover option at BPA's discretion as required and permitted by the FERC. BPA will pay Idaho Power's Network Transmission Service rates as established under Attachment H of the Company's OATT.	Following BPA Public Process, March 2023 **N/A**

	Agreement	Term Sheet Identification	Parties	Description	Anticipated Execution
4	**Purchase, Sale, and Security Agreement**	§ 3(b)(2) and § 3(b)(3)	Idaho Power and BPA	The Purchase, Sale, and Security Agreement provides for the transfer by BPA to Idaho Power of BPA's permitting interest in the B2H project under the Joint Permitting Agreement. Provisions include: • Idaho Power's reimbursement to BPA for the transfer of BPA's permitting interest in an amount consisting of BPA's investment in the B2H project prior to the transfer date ("Transferred Permitting Interest"). • BPA's security payment to Idaho Power of an additional $10 million ("Seller's Security"). • Accrual of interest on both the Transferred Permitting Interest and Seller's Security, payable by Idaho Power to BPA, from the date of energization of B2H, at a rate of 3.25% compounded annually. • The repayment by Idaho Power to BPA of the Seller's Security plus all accrued interest will occur within 60 days following energization of B2H. • The repayment by Idaho Power to BPA of the Transferred Permitting Interest plus all accrued interest will occur: ○ Starting year 11 following B2H energization of B2H if the total load of the NITSAs for any rolling twelve-month basis averages 400 MW or more prior to the tenth anniversary of energization ("Repayment Event"), or ○ The next anniversary date of energization following the Repayment Event if the total load of the NITSAs for any rolling twelve-month basis averages 400 MW or more after the tenth anniversary of B2H energization. • Once repayment of the Transferred Permitting Interest begins, Idaho Power will make monthly payments to BPA starting at $40,000 per month for the first twelve-month interval and increase by $40,000 for each successive twelve-month interval. • Should Idaho Power not receive all governmental authorizations including permits and Certificates of Public Convenience and Necessity ("CPCN") or decides to delay or not to proceed with further development or construction of the B2H project, by January 1, 2025, Idaho Power will return to BPA the Seller's Security.	Following BPA Public Process, March 2023 **N/A**

	Agreement	Term Sheet Identification	Parties	Description	Anticipated Execution
5	**Joint Purchase and Sale Agreement ("JPSA")**	§ 3(a)(5) and § 3(a)(7)	Idaho Power and PacifiCorp	Idaho Power and PacifiCorp desired to exchange undivided ownership interests in certain transmission assets to provide transmission capacity that better aligns with the current configuration of the parties' respective future needs following the addition of B2H. The JPSA facilitates these asset exchanges and is contingent upon regulatory approvals for both parties. Under the purchase and sale provisions: • PacifiCorp will convey to Idaho Power an ownership interest in identified Four Corners/Populus assets, • PacifiCorp will convey to Idaho Power an ownership interest in identified Goshen area assets, • Idaho Power will convey to PacifiCorp an ownership interest in identified Borah/Midpoint West assets, • The purchase price of the assets being conveyed will be equal to the conveying party's net book value, and • Acquired assets of both parties will be operated and maintained in accordance with the Second Amended and Restated Joint Ownership and Operating Agreement ("JOOA"). In addition, the JPSA identifies the following conditions precedent upon closing of the JPSA: • PacifiCorp will release to Idaho Power 200 MW of bidirectional transmission rights on the Four Corners/Populus assets, • Idaho Power will transfer to PacifiCorp 300 MW of west-to-east firm, PTP transmission service between Midpoint and Borah, and • Idaho Power will transfer to PacifiCorp 600 MW of east-to-west firm, PTP transmission service between Borah and Hemingway.	Following BPA Public Process, March 2023 **VAIL**

	Agreement	Term Sheet Identification	Parties	Description	Anticipated Execution
6	**Second Amended and Restated JOOA**	§ 3(a)(6) and § 3(c)	Idaho Power and PacifiCorp	Idaho Power and PacifiCorp will expand the existing JOOA, as amended and restated August 22, 2019, to include ownership, operation and maintenance provisions associated with the B2H project. In addition, as a condition precedent to closing of the purchase and sale transactions identified in the JPSA, the Second Amended and Restated JOOA will include: • Operation and maintenance provisions associated with the assets acquired by both parties under the JPSA, • The transfer of ownership by Idaho Power to PacifiCorp for 300 MW of west-to-east transmission assets between Midpoint 500 and Borah, • The transfer of ownership by Idaho Power to PacifiCorp for an additional 600 MW of east-to-west transmission assets between Borah and Hemingway, and • The transfer of ownership by PacifiCorp of 200 MW of bi-directional transmission assets between Populus, Mona and Four Corners.	To be drafted, to be effective upon energization of B2H **VAIL**
7	**Boardman to Hemingway Transmission Project Joint Construction Funding Agreement**	§ 3(a)(10), § 3(a)(12), and § 3(d)	Idaho Power and PacifiCorp	This agreement will provide definitive terms and conditions by which Idaho Power and PacifiCorp will jointly support and contribute funds, for the procurement, construction, and commissioning of the B2H project, to allow for energization of the project by the earliest in-service date needed by the parties. In addition, it appoints Idaho Power as the construction project manager, providing for full power and authority to do all things necessary or proper to develop and construct the B2H project. The Midline Series Capacitor Project Funding Agreement identified in § 3(a)(12) of the Term Sheet was initially as a separate agreement but has been subsequently incorporated into the overall construction plan for B2H. The work will include installation of the Midline Series Capacitor substation, which is necessary to reduce simultaneous interactions between the NW AC Intertie, central and southern Oregon load service, and Path 14 (Idaho to Northwest).	To be drafted, not required for BPA Public Process, July 2023 **VAIL**

	Agreement	Term Sheet Identification	Parties	Description	Anticipated Execution
8	**Longhorn Substation Funding Agreement**	§ 3(a)(4)	Idaho Power, BPA and PacifiCorp	As outlined in the conditions precedent to closing of the JPSA, PacifiCorp, Idaho Power and BPA will enter into an agreement for the Longhorn substation for the funding by Idaho Power and PacifiCorp of a portion of the assets at and directly adjacent to the Longhorn substation near Boardman, Oregon, where B2H will interconnect. Provisions include: • A use of facilities charge or other charge pursuant to BPA's OATT to be paid by Idaho Power and PacifiCorp to allow the parties to transact across the Longhorn bus in the future, and • Ownership, operation, and maintenance of B2H equipment by Idaho Power and PacifiCorp, including (1) a B2H project-related series capacitor at the Longhorn substation, (2) the B2H project shunt line reactors at Longhorn, and (3) any ancillary equipment required to support the B2H project series capacitor and shunt line reactors. The agreement will be contingent upon BPA completing its obligations and responsibilities under various environmental compliance laws.	To be drafted, not required for BPA Public Process, March 2023 **VAIL**
9	**Midpoint 500/345-kV Transformer Project Construction Agreement ("Midpoint Transformer Construction Agreement")**	§ 3(a)(5)	Idaho Power and PacifiCorp	Under the Midpoint Transformer Construction Agreement, and in conjunction with the JPSA, Idaho Power will make capital upgrades to the Midpoint 500-kV and 345-kV transmission substations, including a second 500/345-kV transformer bank and 345-kV tie line. The assets will be jointly owned by the parties as illustrated in Exhibit A of the JPSA and in accordance with the Second Amended and Restated JOOA.	To be drafted, not required for BPA Public Process, March 2023 **VAIL**
10	**Kinport – Midpoint 345-kV Series Capacitor Bank Project Construction Agreement ("Kinport Capacitor Bank Construction Agreement")**	§ 3(a)(5)	Idaho Power and PacifiCorp	Under the Kinport Capacitor Bank Construction Agreement, and in conjunction with the JPSA, Idaho Power will make capital upgrades to the Midpoint 345-kV transmission line, by installing the Kinport-Midpoint 345-kV Series Capacitor Bank. The assets will be jointly owned by the parties as illustrated in Exhibit A of the JPSA and in accordance with the Second Amended and Restated JOOA.	To be drafted, not required for BPA Public Process, March 2023 **VAIL**

	Agreement	Term Sheet Identification	Parties	Description	Anticipated Execution
11	**Transmission Service Agreements**	§ 3(a)(8), § 3(a)(9) and § 3(a)(11)	Idaho Power, PacifiCorp, and/or BPA	The following transmission service requests will be executed or changes to existing transmission services agreements will be made: • Idaho Power will acquire from BPA 500 MW of point-to-point ("PTP") transmission service from Mid-C to Longhorn, • PacifiCorp will renew its 510 MW of PTP transmission service from Idaho Power, • BPA will redirect its two 100 MW PTP transmission service agreements that it takes from Idaho Power and assign to PacifiCorp.	Not required for BPA Public Process, March 2023 **LINK**
12	**Amendment to Midpoint-Meridian Agreement**	§ 3(a)(1)(I)(e)(iii)	PAC and BPA	Removes PAC's bidirectional scheduling rights over Buckley-Summerlake line, thereby facilitating the revisions to the PTP tables summarized above in BPA PTP Contract No. 04TX-11722.	**LINK**
13	**Redirect and Assignment of 200 MW of PTP transmission service on IPC's system (BPA to PAC)**	§ 3(a)(11)	PAC, BPA and IPC	As summarized in draft letter agreement between BPA and PAC, BPA agrees, upon B2H energization, to submit a redirect request to IPC for its two existing 100 MW conditional firm PTP service agreements on IPC's system (SA 324 and SA 342), reflecting for each a new POR of Walla Walla (SE Wash) and a new POD of Borah (SE Idaho). BPA will then assign the redirected SAs to PAC upon its request. [This is referred to in the third bullet of IPC's Row 11 above.]	**LINK**
14	**Updates to PAC's PTP Service Tables with BPA reflecting central Oregon load service**	§ 3(a)(1)(I)	PAC and BPA	Revisions to 15 PTP service tables under PAC's existing Long-Term Firm PTP Service Agreement with BPA (BPA No. 04TX-11722) related to service into central Oregon.	**LINK**
15	**Coordination Agreement re: Meridian Series Capacitor Bank Project**	§ 3(a)(1)(IV)	PAC and BPA	Draft coordination agreement between PAC and BPA sets forth the agreed process for PAC's intended upgrade, upon BPA notice, of the existing Meridian series capacitor banks on the PAC section of the Dixonville-Meridian-Klamath Falls-Captain Jack lines in southern Oregon, as detailed in March 2021 report titled "Phase II Joint Study Report (2020-2021), Boardman to Hemingway (B2H) and Incremental Central Oregon Load."	**VAIL**

REDACTED
Docket No. 20000-___-EN-23
Witness: Joelle R. Steward

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Joelle R. Steward

February 2023

Q. Please state your name, business address, and present position with PacifiCorp dba Rocky Mountain Power ("Rocky Mountain Power" or the "Company").

A. My name is Joelle R. Steward. My business address is 1407 West North Temple, Salt Lake City, Utah 84116. My present position is Senior Vice President, Regulation for the Company.

QUALIFICATIONS

Q. Please summarize your education and business experience.

A. I have a B.A. degree in Political Science from the University of Oregon and an M.A. in Public Affairs from the Hubert Humphrey Institute of Public Policy at the University of Minnesota. Between 1999 and March 2007, I was employed as a Regulatory Analyst with the Washington Utilities and Transportation Commission. I joined the Company in March 2007 as a Regulatory Manager, responsible for all regulatory filings and proceedings in Oregon. On February 14, 2012, I assumed responsibilities overseeing cost of service and pricing for the Company. In May 2015, I assumed broader oversight over Rocky Mountain Power's regulatory affairs in addition to the cost of service and pricing responsibilities; in 2017, I became Vice President, Regulation for Rocky Mountain Power, and in 2021, I assumed my current position.

Q. Have you appeared as a witness in prior regulatory proceedings?

A. Yes. I have testified on various matters in the states of Wyoming, Idaho, Oregon, Utah, and Washington.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. My testimony explains the Company's proposal to construct Energy Gateway

Segment H, the Boardman to Hemingway transmission line ("B2H" or the "Project"). I provide an overview of the Company's Application, which includes a request for waiver of the obligation to obtain a non-situs certificate of public convenience and necessity ("CPCN") and of the advanced review process set forth in the stipulation approved in Docket No. 20000-384-ER-10, Record No. 12702 ("Advanced Review Process"). I explain why it is in the public interest to waive the non-situs CPCN and Advanced Review Process requirements in this case and, alternatively, how B2H is necessary and in the public interest. I also provide the estimated rate impacts for the Project, discuss the Company's financial ability to invest in the Project, and describe how the Company has pursued the Project in good faith.

Q. Please summarize your testimony.

A. A waiver of the non-situs CPCN and Advanced Review Process requirements for B2H is in the public interest for several reasons. First, construction of B2H will improve the Company's ability to export generation from resource-rich states like Wyoming by increasing connections between the Company's balancing authority areas ("BAA") and enable lower-cost and more reliable transmission service for the Company's growing customer load. Second, due to the complexity of B2H and factors outside of the Company's control, there is a time-limited period in which to complete underlying transactions and obtain regulatory reviews to allow timely construction of B2H and maximize the benefits of the Project. Finally, granting a waiver will not harm Wyoming customers because a waiver will not affect customers' rates, parties can raise any concerns regarding the prudency of B2H in a general rate case before the Project is added to the Company's rate base, and there are already multiple venues in which the need for the Project is undergoing extensive review.

Alternatively, I recommend the Commission issue a non-situs CPCN for the Project and determine that B2H has satisfied the requirements of the Advanced Review Process because B2H is necessary and in the public interest. B2H is necessary to enable lower-cost and more reliable transmission service for the Company's growing customer load and enhance grid reliability by increasing transmission between the Company's eastern BAA ("PACE") and its western BAA ("PACW"). B2H is in the public interest because the Project will increase transmission capacity between PACE and PACW. B2H will allow the Company to export 818 megawatts ("MW") of additional generation capacity from Wyoming, Utah, and Idaho generators in PACE to Oregon, Washington, and California customers in PACW. Additionally, B2H provides significant present value revenue requirement differential ("PVRR(d)") net customer benefits in all scenarios.

The Company seeks a Commission order on the requested waivers within 20 business days. If the Commission denies the Company's waiver requests, the Company requests expedited review of its Application to ensure issuance of an order no later than June 30, 2023.

BACKGROUND OF B2H

Q. Please provide a brief description of the Company's operations in Wyoming.

A. Rocky Mountain Power is a major employer, taxpayer, energy producer and provider in the state of Wyoming. Rocky Mountain Power is the largest electricity provider in Wyoming, providing service to 41 percent of customers with 54 percent of electricity sales in the state.[1] The Company has the privilege and opportunity of providing safe, reliable, and reasonably priced electric service to over 142,000 customers in 15 counties in Wyoming. In doing so, it employs over 1,000 people[2] in the state to operate and maintain 12 thermal generation units comprising 3,040 megawatts ("MW") of capacity,[3] 12 wind generation facilities with 1,586 MW of capacity,[4] the Jim Bridger mine, and over 11,000 miles of transmission and distribution lines. The Company also has contracts with a number of independent power producers in the state of Wyoming that operate facilities representing approximately 1,040 MW of installed capacity.[5]

Q. Please describe B2H.

A. B2H is an approximately 300-mile-long 500-kilovolt ("kV") electric transmission line that would extend from a switching station proposed to be constructed near Boardman, Oregon to the existing Hemingway Substation located in Owyhee County, Idaho. The transmission line would cross five Oregon counties: Malheur, Baker, Union, Umatilla, and Morrow Counties. In Idaho, the project would be located only in Owyhee County.

Q. Are other parties involved in constructing and owning B2H?

A. Yes. In addition to the Company, Idaho Power Company ("IPC") and the Bonneville Power Administration ("BPA") have an interest in B2H.

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[1] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. (Calendar Year 2021). Retrieved February 2, 2023, from https://www.eia.gov/electricity/data/eia861.

[2] Rocky Mountain Power's Annual Report for 2021 filed with the Wyoming Public Service Commission as required by Chapter 3, Section 32.

[3] *In re Filing of Rocky Mountain Power's Integrated Resource Plan (IRP) for 2021*, Docket No. 20000-603-EA-21 (Record No. 15935) IRP at 137-38, Tables 6.2, 6.3 (Sept. 1, 2021). PacifiCorp power plants located in Wyoming include Dave Johnston (four coal-fueled units), Jim Bridger (four coal-fueled units jointly owned with Idaho Power Company), Naughton (two coal-fueled units and one unit that was converted to natural gas), and Wyodak (one coal-fueled unit jointly owned with Black Hills Power).

[4] *Id.* at 139, Table 6.4.

[5] *Id.* at 140-42, Tables 6.5 and 6.6.

Q. Why does the Company propose taking ownership of B2H?

A. B2H is a component of Energy Gateway and has been an integral component of the long-term transmission plan for the region for over a decade.[6] The Company is moving forward with B2H now because current circumstances make the Project both necessary and economic.

Q. What is the construction schedule for B2H?

A. Construction of the Project is expected to take three years. To energize B2H in 2026, IPC must begin construction during the summer of 2023. For that reason, IPC and the Company are currently working to secure all necessary approvals no later than June 30, 2023.

Q. Why is the 2026 in-service date important to the Company?

A. As explained in the testimony of Mr. Rick T. Link, the Company's loads are growing and B2H is the most cost-effective means of meeting this demand.

Q. In addition to the Commission, do any other state agencies have jurisdiction over the Project?

A. Yes. The Project must be approved by the Oregon Energy Facility Siting Council ("EFSC"), the Public Utility Commission of Oregon ("OPUC"), and the Idaho Public Utilities Commission ("IPUC"), in addition to local government permits and approvals.

Q. Are any federal agencies involved in reviewing B2H?

A. Yes. As project manager, IPC also completed the federal review process required under the National Environmental Policy Act ("NEPA"). In 2007, IPC filed a Preliminary

[6] *See* DEP'T OF ENERGY, *Obama Administration Announces Job-Creating Grid Modernization Pilot Projects* (Oct. 5, 2011) (available at https://www.doi.gov/pressreleases/Obama-Administration-Announces-Job-Creating-Grid-Modernization-Pilot-Projects) (last visited Dec. 30, 2022) (identifying B2H as a pilot program for transmission projects envisioned across the country).

Draft Application for Transportation and Utility Systems and Facilities on Federal Lands and began scoping routes. The following year, IPC submitted application materials to the Bureau of Land Management as the lead agency for the federal NEPA review. Additionally, because the proposed route includes land managed by the United States Forest Service and the Navy, those agencies conducted additional review of the proposed routes and approved rights-of-way across lands under their jurisdictions.

WAIVERS OF THE NON-SITUS CPCN AND ADVANCED REVIEW PROCESS ARE IN THE PUBLIC INTEREST

Q. Is the Company required to obtain a non-situs CPCN for B2H?

A. Yes. My understanding is that Wyoming Statute § 37-2-205.1(a) requires a non-situs CPCN for projects like B2H. However, Commission Rule Chapter 3, Section 21(a)(iii) allows the Commission to waive that requirement if doing so is in the public interest.

Q. Is the Project subject to the Advanced Review Process?

A. Yes. In the Company's 2010 Wyoming general rate case, the Commission approved a stipulation that addresses review of certain Energy Gateway transmission projects, including B2H.[7] While the Project is subject to the Advanced Review Process, the Company requests a waiver of that process in this case.

Q. Is a waiver of the non-situs CPCN and Advanced Review Process in the public interest in this case?

A. Yes. Waiver of the non-situs CPCN and Advanced Review Process requirements for B2H is warranted because: (1) construction of the B2H line is in the public interest; (2)

[7] *In The Matter Of The Application Of Rocky Mountain Power For Approval Of A General Rate Increase In Its Retail Electric Utility Service Rates In Wyoming Of $97.9 Million Per Annum Or An Average Overall Increase Of 17.3 Percent,* 20000-384-ER-10, Record No. 12702, Stipulation Appendix A (Sept. 2011). [hereinafter "2010 Stipulation"].

due to factors beyond the Company's control there is a time-limited window for completing the underlying transactions and obtaining regulatory approvals to allow construction to proceed as scheduled in July 2023, which is necessary to achieve B2H's planned 2026 in-service date and maximize the customer benefits of the Project; and (3) waiving the non-situs CPCN requirement and the Advanced Review Process will not harm Wyoming customers.

Q. If construction is expected to begin in July 2023, why is the Company only now filing for the non-situs CPCN?

A. While development of B2H has been ongoing for many years, the current structure of the B2H transaction between the Company and BPA was not finalized until January 2023. Before finalizing the structure, the Company updated its economic analysis of the Project in December 2022 to affirm the decision to move forward with construction, pending receipt of the necessary regulatory approvals. The Company began preparing its filings for Idaho and Wyoming immediately thereafter.

<u>Construction of B2H Is Necessary and in the Public Interest.</u>

Q. Has the Company previously analyzed the public interest factors supporting construction of B2H?

A. Yes. As discussed in the testimony of Mr. Link, the Company has included B2H in its preferred portfolio in the 2021 Integrated Resource Plan ("IRP") as the least-cost, least-risk means of addressing the Company's needs.

Q. Is B2H necessary for the Company at this time?

A. Yes. As explained in detail in the testimony of Mr. Link and Mr. Vail, the Project is necessary primarily for three reasons: (1) B2H provides needed transmission connections between the Company's eastern and western BAAs; (2) B2H is the most cost-effective means of serving growing customer load in central Oregon; and (3) B2H results in significant cost-savings for serving growing customer load near the proposed Longhorn substation because the Company will no longer have to rely on contracts with third-party transmission providers to serve those customers.

Q. Is B2H the least-cost means of meeting those Company needs?

A. Yes. Mr. Link explains the economic analysis of B2H in detail in his testimony and demonstrates that the Project is expected to result in net benefits of approximately $1.713 billion.

Q. According to Mr. Link, the need for B2H appears to be driven largely by increased load growth in Oregon. How will B2H provide benefits to Wyoming?

A. As Mr. Link explains, the Project benefits customers by allowing the Company to avoid investments in alternative transmission and generation resources and reduces the Company's transmission expense included in its net power costs. Under the current 2020 Protocol used to allocate costs among PacifiCorp's jurisdictions, a portion of these system avoided costs would have been paid by Wyoming customers. Therefore, Wyoming customers directly benefit from B2H because it reduces the costs that would have otherwise been incurred absent the Project. In addition, as Oregon's load growth increases, Oregon customers pay a proportionally larger share of the Company's overall costs. This, in turn, means that Wyoming customers pay proportionally less.

<u>Due to the Complexity of B2H, There Is a Time-Limited Window for Completing the Underlying Transactions and Obtaining Regulatory Approvals to Allow Construction to Proceed as Scheduled, Which Is Necessary to Maximize Customer Benefits.</u>

Q. You mentioned above that construction must begin by 2023 to ensure the Project is placed in-service by 2026. Are there additional processes that must be completed before beginning construction?

A. Yes. The B2H parties must execute numerous contracts relating to the Project before construction. Additionally, IPC and the Company are both pursuing the necessary regulatory approvals.

Q. Which agreements must the parties execute?

A. The agreements relating to B2H are summarized in the Term Sheet, which is included as RMP Exhibit 3.1 to Mr. Link's testimony. B2H is a complex transaction that involves two public utilities (IPC and the Company) and a governmental agency (BPA). The specific agreements included in the Term Sheet are discussed in greater detail in the testimonies of Mr. Link and Mr. Vail.

Q. What approvals must IPC obtain prior to construction?

A. My understanding is that IPC must obtain a site certificate from EFSC and a CPCN from both the OPUC and IPUC. Additionally, IPC must secure various local land use permits in the counties and municipalities where the Project is located. However, it is my understanding that, once IPC obtains a site certificate in Oregon, the affected local governments in Oregon must issue those permits promptly without hearings or other proceedings.[8]

[8] Oregon Revised Statute 469.401(1) ("After issuance of the site certificate or amended site certificate, any affected state agency, county, city and political subdivision shall, upon submission by the applicant of the proper

Q. Has IPC secured any approvals for B2H?

A. Yes. IPC has completed the lengthy approval process at EFSC to obtain a site certificate. EFSC issued the site certificate on October 6, 2022. My understanding is that the site certificate is currently under review on appeal before the Oregon Supreme Court.

Q. When is the Oregon Supreme Court expected to rule on those appeals?

A. My understanding is that the court is required by statute to issue its rulings no later than June 6, 2023.[9]

Q. Has IPC begun the process to obtain the CPCNs in Oregon and Idaho?

A. Yes. IPC filed its petition for a CPCN in Oregon on September 30, 2022.[10] The OPUC expects to issue a final order in that case by June 30, 2023.[11] IPC filed its application for a CPCN in Idaho on January 9, 2023, similarly requesting a final order by June 30, 2023.[12]

applications and payment of the proper fees, but without hearings or other proceedings, promptly issue the permits, licenses and certificates addressed in the site certificate or amended site certificate, subject only to conditions set forth in the site certificate or amended site certificate.").

[9] Oregon Revised Statute ("ORS") 469.403(6) (requiring the Oregon Supreme Court to render a decision on an appeal of a site certificate within six months of the filing of a petition for review). The appellants filed their petitions for review on December 6, 2022.

[10] *In re Idaho Power Company's Petition for Certificate of Public Convenience and Necessity*, Public Utility Commission of Oregon ("OPUC") Docket PCN 5, Petition for CPCN (Sept. 30, 2022) (available at https://edocs.puc.state.or.us/efdocs/HAA/pcn5haa84035.pdf) (last visited Dec. 30, 2022).

[11] *In re Idaho Power Company's Petition for Certificate of Public Convenience and Necessity*, OPUC Docket PCN 5, Administrative Law Judge's Memorandum at 2 (Oct. 20, 2022) (available at https://edocs.puc.state.or.us/efdocs/HDA/pcn5hda15939.pdf) (last visited Dec. 30, 2022).

[12] *In re Idaho Power Company's Application for a Certificate of Public Convenience and Necessity for the Boardman to Hemingway 500-kV Transmission Line*, Case No. IPC-E-23-01, Application (Jan. 9, 2023) (available at https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2301/CaseFiles/20230110Application_Redacted.pdf) (last visited Jan. 19, 2023).

Q. Has the Company filed a CPCN application for B2H in other states?

A. Yes. The Company filed an application for a CPCN with the IPUC on January 27, 2023.[13] Consistent with the schedule for IPC's requested CPCN in Idaho, the Company requested that the IPUC issue a CPCN no later than June 30, 2023.

Q. Will the need for B2H be assessed in the other regulatory approval proceedings that IPC and the Company have initiated?

A. Yes. In the EFSC proceedings, IPC demonstrated compliance with EFSC's Need Standard for Non-Generating Facilities, which requires an applicant to "demonstrate[] the need for the facility."[14] In the CPCN proceedings in Oregon, IPC must prove "the necessity, safety, practicability and justification in the public interest" for B2H.[15] Finally, in the Idaho CPCN proceedings both the Company and IPC must demonstrate that "the present or future public convenience and necessity require or will require" construction of B2H.[16]

Q. You mentioned that BPA is also involved in B2H. Is BPA required to conduct any review before construction?

A. Yes. Independent of both IPC's and the Company's efforts to secure state regulatory approvals, BPA must complete its own process consistent with federal law.

Q. Has BPA begun the public process for its role in B2H?

A. Yes. On January 9, 2023, BPA released its Letter to the Region that provided public notice via their Tech Forum platform to customers and stakeholders announcing their

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[13] *In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity Authorizing Construction of the Boardman to Hemingway 500-kV Transmission Line Project*, Case No. PAC-E-23-01, Application (Jan. 27, 2023).
[14] Oregon Administrative Rules ("OAR") 345-023-0005.
[15] ORS 758.015(2). IPC has initiated the CPCN process in Oregon.
[16] Idaho Code Section 61-526.

completion of B2H negotiations and releasing the customer engagement schedule, identifying dates for the comment period, customer workshop, and an expected final decision in March 2023. A copy of the notice is included as Exhibit 2.1 to my testimony.

Q. Given these myriad procedural requirements for the B2H parties, would the waivers the Company requests in the Application support timely construction of B2H?

A. Yes. There are many remaining steps that the Company and other B2H parties must still complete before construction. For that reason, any reduction to the required regulatory filings will increase the likelihood that IPC may begin construction on time to complete B2H in time for the expected 2026 in-service date.

Q. Does that mean waiving the non-situs CPCN and Advanced Review Process requirements would make it more likely that the Company can secure the Project benefits that you discussed above?

A. Yes. Alternatively, if the Commission instead considers the Company's Application for non-situs CPCN and the Advanced Review Process, it is imperative that the Commission grant the Company's request for expedited review to ensure completion of this docket by June 30, 2023.

<u>Waiver of the Non-Situs CPCN and Advanced Review Process Requirements Will Not Harm Wyoming Customers.</u>

Q. Does the Company intend to condemn or otherwise obtain any property in Wyoming to construct B2H?

A. No. B2H does not require any Wyoming property for its construction.

Q. Is the Company seeking any ratemaking treatment for B2H in this docket?

A. No.

Q. If the Commission grants the Company's requests for waivers, would customers' rates be affected?

A. No. The Company's retail customers in Wyoming will not experience any change in rates if the Commission grants the Company's waiver requests because granting a waiver would not immediately allow the Company to include B2H in its rate base.

Q. When would the Company's Wyoming customers be affected?

A. Customers' rates would change only after the Commission approves adding B2H to the Company's rate base in a general rate case.

Q. Has the Company estimated the rate impact of B2H for Wyoming customers?

A. Yes. As set forth in Confidential Table 1, when B2H comes into service in 2026, the Company estimates that the rate impact to Wyoming customers will be approximately 1.95 percent. However, this calculation is preliminary as final revenue requirement calculations and rate impacts will be done when the Company seeks to include the project in rates in a future general rate case, including using jurisdictional allocations applicable at that time.

Confidential Table 1

B2H Simplified Revenue Requirement ($ millions)			
	Total-Company	Wyoming	Wyoming Customer Rate Impact
Gross Plant In-Service	[redacted]	[redacted]	
Accum. Depr.	[redacted]	[redacted]	
Net Plant	[redacted]	[redacted]	
Annual Depr. Rate	1.75%	1.75%	
Depr. Exp.	$14.76	$2.16	
Total Annual Rev. Req.		$ 12.88	1.95%
Pre-Tax ROR		8.77%	

Footnotes:

Wyoming allocated balances assume 14.625% SG allocation factor from 2020 GRC, Docket No. 20000-578-ER-20.

Revenue requirement assumes a December 31, 2026 in-service date.

Rate base is calculated on a 13- month average and does not contemplate deferred income taxes.

Wyoming customer rate impact is calculated on Wyoming revenues effective 5/1/2022.

Depreciation rate is assumed using the composite transmission deprecation rate from the 2020 GRC, Docket No. 20000-578-ER-20.

Pre-Tax return on rate base is assumed from the 2020 GRC, Docket No. 20000-578-ER-20.

Q. If the Commission grants the Company's waiver requests, would stakeholders be precluded from raising arguments regarding B2H in any subsequent general rate case?

A. I am not an attorney, but my understanding is that customers would not be precluded from raising any challenges to B2H in the Company's next general rate case. The Company's waiver requests would not result in a determination on the prudence of B2H, and the Project would be subject to the typical prudence review just like any other asset proposed for inclusion in the Company's rate base.

Q. Is this treatment of issuing a CPCN for a proposed asset and then later reviewing the prudence of the asset in a subsequent rate case consistent with the Commission's treatment of past projects for which the Company has sought a CPCN?

A. Yes. In past cases issuing a CPCN, including for projects subject to the Advanced Review Process, the Commission has been clear that issuance of a CPCN is not a form of preapproval and that prudence remains a subject for a later rate case.[17]

Q. If the Commission grants the Company's waiver requests, would the need for the Project still be adequately assessed?

A. Yes. As discussed above, in addition to the Commission's post-construction prudence review, the need for the Project has been or will be thoroughly analyzed in proceedings before Oregon EFSC, the OPUC, and the IPUC.

B2H SATISFIES THE REQUIREMENTS FOR A NON-SITUS CPCN AND THE ADVANCED REVIEW PROCESS

Q. What are the requirements for a non-situs CPCN?

A. My understanding is that Wyoming law requires the Company to demonstrate that the present or future need for the proposed non-situs facility is prudent and in the public interest.[18]

[17] *See, e.g.*, *In re Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4 Located Near Point of Rocks,* Wyoming, Docket No. 20000-418-EA-12 (Record No. 13314), Opinion ¶31 (May 29, 2013).
[18] Wyo. Stat. §37-2-205.1(a).

Q. What standard does the Commission apply in the Advanced Review Process?

A. My understanding is that the Advanced Review Process requires the Commission to rule on "whether the proposed construction of the transmission line is reasonable and in the public interest in advance of the line being constructed."[19]

Q. Why is B2H necessary?

A. As I discussed above and as explained further in the testimony of Mr. Vail and Mr. Link, B2H is necessary for several reasons, including the increased connection between the Company's BAAs and lower-cost reliable transmission service for the Company's growing customer load.

Q. Why is B2H in the public interest?

A. As discussed above and explained further in the testimony of Mr. Link, B2H is in the public interest because it results in substantial net benefits compared to the facilities that would be necessary to serve customers without B2H.

Q. Has the Company projected the PVRR(d) benefits of B2H by comparing costs and benefits with and without B2H?

A. Yes. Mr. Link has performed this economic analysis and explains in his testimony that B2H results in significant net benefits in *all* price-policy scenarios.

Q. Would granting CPCNs or approval in the Advanced Review Process guarantee cost recovery?

A. No. It is my understanding that Wyoming Statute § 37-2-205.1(d), which governs non-situs CPCNs, specifically states that issuance of a non-situs CPCN "shall not confer the right to recover a specific amount" and that "[a]ctual costs of the capital investment

[19] 2010 Stipulation at ¶13(a)(ii).

may be considered by the commission in a separate rate case determination." Additionally, I understand that the Advanced Review Process similarly does not pre-approve the projects for purposes of ratemaking.[20]

Q. Is the Company also required to demonstrate financial ability and good faith?

A. My understanding is that those standards apply to a CPCN for facilities within Wyoming, but do not necessarily apply to non-situs CPCNs.

Q. That being said, does the Company have the financial ability to build B2H?

A. Yes. As an initial matter, the Company is not solely financially responsible for constructing B2H. As discussed above, IPC is responsible for funding 45.45 percent of the Project. For the Company's share of B2H, the Company intends to finance the Project through its normal sources of capital, both internal and external, including net cash flow from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, capital contributions, and other sources. Although B2H is a significant Company investment, the financial impact will not impair the Company's ability to continue to provide safe and reliable electricity service at reasonable rates.

Q. Is the Company acting in good faith?

A. Yes. The Company's development efforts have all been in good faith. The Company's plans are for the benefit of its customers and the Company has acted reasonably during

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[20] S*ee, e.g.*, 2010 Stipulation at ¶¶ 86-87, 128. The 2010 Stipulation also includes the following provision: "If the Commission grants a CPCN for a particular segment or rules that a particular segment is reasonable and in the public interest in advance of the segment being constructed, the Parties agree that they will not challenge Rocky Mountain Power's prudence or recovery of the actual costs associated with that segment in any future Wyoming rate case except to the extent (1) that the actual cost of constructing the segment exceeds the estimated costs presented in the application or (2) there is evidence of mismanagement. If such circumstances ever exist, any challenge to the segment will be limited to the prudence of the actual costs in excess of the estimated costs or the impact of the mismanagement." 2010 Stipulation at ¶13(a)(iv).

the course of the development efforts. Additionally, the Company will act in good faith as it executes all contracts necessary to construct B2H.

Q. Are there any other requirements for CPCN applications?

A. Yes. Commission Rule Chapter 3, Section 21(c)(i) sets forth the substantive material that must be included in an application for a non-situs CPCN. Additionally, the stipulation establishing the Advanced Review Process included specific information requirements.[21] The requirements of this rule and the Advanced Review Process are addressed in detail in the Application and in the testimony and exhibits of Mr. Link and Mr. Vail.

OVERVIEW OF THE COMPANY'S FILING

Q. What specific orders is the Company requesting?

A. The Company requests that the Commission waive the requirement to obtain a non-situs CPCN for B2H. Alternatively, the Company provides the necessary information for an order issuing a non-situs CPCN under Wyoming Statute § 37-2-205.1.

Similarly, the Company requests that the Commission waive the Advanced Review Process for the Project. Alternatively, the Company provides in its Application the information necessary for compliance with the Advanced Review Process.

Q. What other witnesses will be testifying on behalf of the Company?

A. In addition to my testimony, the Company's Application is supported by the testimony of the following witnesses:

Mr. Rick T. Link, Senior Vice President of Resource Planning, Procurement, and Optimization, provides the economic analysis demonstrating that the Project is

[21] 2010 Stipulation at ¶ 13(a).

beneficial to Wyoming customers and in the public interest. Mr. Link describes the customer benefits resulting from the timely construction of the Project, and explains the need for the Project. Mr. Link also addresses the agreements relating to the Project.

Mr. Rick A. Vail, Vice President of Transmission, provides a detailed description of the Project and demonstrates that the Project is necessary to improve the reliability of the transmission system. Mr. Vail's testimony describes how the Project will increase the transfer capability between PACE and PACW. Finally, Mr. Vail explains the asset exchanges that will occur between the Company and IPC as a result of this Project.

CONCLUSION

Q. What is your recommendation to the Commission?

A. I recommend that the Commission grant the Company's requests to waive the non-situs CPCN requirement and the Advanced Review Process for B2H because, under the specific facts of this case, a waiver is in the public interest. Alternatively, if the Commission decides not to grant the Company's requests for waivers, I recommend that the Commission issue a non-situs CPCN for the Project and an order affirming completion of the Advanced Review Process. B2H is necessary to improve grid reliability by increasing connections between the Company's east and west BAAs and enhancing the Company's ability to export generation from resource-rich states like Wyoming to load centers in other states. The Project also enables lower-cost and more reliable transmission service for the Company's growing customer load, and avoids acquisition of higher-cost generation and transmission resources.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A WAIVER OF THE NON-SITUS CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR GATEWAY SEGMENT H, THE BOARDMAN TO HEMINGWAY TRANSMISSION PROJECT	)	DOCKET NO. 20000-___-EN-23 (RECORD NO. _______)

AFFIDAVIT, OATH AND VERIFICATION

Joelle R. Steward (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is the Senior Vice President, Regulation and Customer/Community Solutions for PacifiCorp, which is a party in this matter.

Affiant prepared and caused to be filed direct testimony in this proceeding. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant's knowledge, all statements and information contained within the testimony and all of its associated attachments are true and complete and constitute the recommendations of the Affiant in her official capacity as Senior Vice President, Regulation and Customer/Community Solutions.

Further Affiant Sayeth Not.

Dated this 6 day of Feb, 2023

Joelle R. Steward
1407 W. North Temple
Salt Lake City, UT

STATE OF Utah)
) SS:
COUNTY OF Salt Lake)

The foregoing was acknowledged before me by Joelle R. Steward on this 6 day of February, 2023. Witness my hand and official seal.

Notary Public

My Commission Expires:

Feb. 21, 2026

LINDA NORTON
Notary Public - State of Utah
Comm. No. 722954
My Commission Expires on
Feb 21, 2026

Rocky Mountain Power
Exhibit 2.1
Docket No. 20000-___-EN-23
Witness: Joelle R. Steward

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Joelle R. Steward

BPA Letter to Region

February 2023

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

POWER SERVICES

January 9, 2023

In reply refer to: P-6

To parties interested in B2H and Southeast Idaho Load Service:

This notice announces that the Bonneville Power Administration, Idaho Power, and PacifiCorp have concluded negotiations on final agreements that memorialize and effectuate the Boardman to Hemingway, or B2H, with Transfer Service plan of service to southeast and southern Idaho loads. The proposed plan of service would deliver significant benefits for BPA and its customers, including essential congestion relief and removal of the dependence on conditional firm point-to-point service; consolidation of network integration transmission service from a single transfer service provider for all of BPA's deliveries to southeast and southern Idaho loads; and improved costs compared with today's interim service approach.

BPA now proposes to execute the contracts for the B2H with Transfer Service plan of service. Before making a final decision to execute the contracts, BPA is providing regional stakeholders with more information about the contracts and an opportunity to comment.

Attachment A includes background information, an overview of the contracts that BPA is proposing to execute for the B2H with Transfer Service plan of service, and information for how to submit comments.

We look forward to continued discussions with regional stakeholders on this important topic.

Sincerely,

Digitally signed by KIM THOMPSON
Date: 2023.01.09
10:01:57 -08'00'

Kim Thompson
Vice President, NW Requirements Marketing

MICHELLE MANARY
Digitally signed by MICHELLE MANARY
Date: 2023.01.09
10:00:24 -08'00'

Michelle Manary
Vice President, Transmission Marketing

Attachments

ATTACHMENT A

Updated BPA Letter to the Region re: B2H and Southeast Idaho Load Service

I. Background

In a Letter to the Region dated January 18, 2022 ("2022 Letter"), BPA announced its signature of a non-binding term sheet ("Term Sheet") that clarified and updated BPA's role in Idaho Power and PacifiCorp's potential future construction of their new transmission line from Boardman, Oregon to Hemingway, Idaho (the "Boardman to Hemingway Project" or "B2H"). The 2022 Letter provided background on the B2H negotiations, the history of BPA's load service to the six preference customers in Idaho ("Southeast Idaho Load Service" or "SILS customers"), and challenges with the current interim plan of service to these customers' loads. BPA explained how the proposed B2H project could provide BPA a long-term plan of service for the SILS customers that includes BPA taking network transfer service from Idaho Power ("B2H with Transfer Service"). BPA also explained the related challenges associated with BPA's long term service to the 15 preference customers in Southern Idaho, many located near Burley, Idaho, and the benefits that the B2H with Transfer Service plan of service provides to these customers. BPA noted that Idaho Power, PacifiCorp, and BPA intended to negotiate binding contracts to memorialize and effectuate the B2H with Transfer Service plan of service. The 2022 Letter and the Term Sheet are available at [Southeast Idaho Load Service - Bonneville Power Administration (bpa.gov)](bpa.gov).

BPA is pleased to share that negotiations have concluded. BPA now proposes to execute binding contracts for the B2H with Transfer Service plan of service. Before making a final decision to execute the contracts, BPA is providing regional stakeholders with more information about the contracts and an opportunity to comment. BPA is also conducting appropriate National Environmental Policy Act ("NEPA") processes before making a final decision.

Under the B2H with Transfer Service plan of service, BPA's role as permitting partner and potential future partial owner of the B2H project would be removed from the B2H ownership structure. BPA would transfer its B2H permitting interest share to Idaho Power in a Purchase, Sale, and Security Agreement. Idaho Power and PacifiCorp would jointly own and construct the B2H project pursuant to separate agreements between them. To serve the SILS customers' loads, BPA would enter into a network integration transmission service agreement ("NITSA") with Idaho Power under its Open Access Transmission Tariff ("OATT") for service to the five SILS customers in the Goshen area and a second NITSA for service to Idaho Falls. These NITSAs would provide BPA with a single leg of network integration transmission service ("NITS") from Idaho Power to deliver resources from the BPA transmission system to the SILS customers' various points of delivery.

To facilitate Idaho Power's ability to serve the SILS customers' loads as network loads, PacifiCorp would transfer assets to Idaho Power in an agreement between PacifiCorp and Idaho Power. This asset transfer allows the SILS customers' loads currently served on PacifiCorp's southeast Idaho transmission system to be served fully on Idaho Power's transmission system. In consideration of PacifiCorp transferring assets to Idaho Power and with other stipulations, BPA would provide point-to-point ("PTP") transmission service in central Oregon to PacifiCorp through the redirect of existing PTP service paired with a conversion of legacy scheduling rights in central Oregon to PTP service. Additionally, BPA would provide Idaho Power with PTP service to the B2H interconnection at the proposed BPA Longhorn substation near Boardman, Oregon. PacifiCorp and Idaho Power would take and pay for the PTP services pursuant to BPA's OATT and rate schedules. BPA would also enter into contracts with Idaho Power and PacifiCorp associated with the B2H interconnection at the proposed BPA Longhorn substation.

For BPA, the construction of B2H by Idaho Power and PacifiCorp in conjunction with the transfer of assets between Idaho Power and PacifiCorp means that BPA would receive firm network transmission service for its SILS customer loads using only one wheel of transmission beyond the BPA transmission system (as opposed to two wheels, which is part of the current interim plan of service). By stepping out of the B2H ownership structure, BPA also avoids the complexity and foregone revenue of other previously considered plans of service.

This letter announces the final terms of the B2H with Transfer Service plan of service. Section II describes the agreements that BPA proposes to execute. Section III provides an explanation of BPA's business case for this plan of service, including the quantitative and qualitative benefits. Key benefits include elimination of today's reliance on conditional firm PTP service for deliveries of BPA resources to the SILS customers' loads, migration of SILS customer loads to firm network transmission service, financial benefits of having a single wheel of transmission for service to the SILS customer and incremental revenues from new PTP sales, congestion relief that benefits BPA's deliveries for all Southern and Southeast Idaho customers, and eliminating today's interim service's reliance on market purchases that carry cost, availability, and carbon-content risks.

Finally, this letter initiates the start of a public comment period that will conclude on February 9, 2023. Section IV provides information for how stakeholders may submit comments. BPA will answer stakeholder questions and discuss aspects of the business case associated with the B2H with Transfer Service plan of service at the January 23, 2023, workshop. BPA intends to make a final decision regarding whether to execute the agreements for the B2H with Transfer Service plan of service in a Closeout Letter to the region on or about March 23, 2023.

II. Final Terms for the B2H with Transfer Service Plan of Service

A. Arrangements to effectuate long-term firm transfer service for the SILS customers' loads

Under the B2H with Transfer Service plan of service, BPA would not become an owner or participate in the construction of the B2H project. Instead, BPA would sell its B2H permitting interest share (around 24%) and its right to future ownership in B2H to Idaho Power. Together with Idaho Power's existing rights to the B2H project, this sale of BPA's permitting interest would allow Idaho Power to fund construction and hold a 45.45% ownership share in the B2H project. PacifiCorp would continue to fund construction and hold a 55.55% ownership share in the B2H project.

To serve the SILS customers' loads after the B2H project is constructed, BPA would purchase long-term firm NITS from Idaho Power. Currently, service to the SILS customers' loads uses transmission facilities that are owned by PacifiCorp. In order to facilitate Idaho Power's ability to serve the SILS customers' loads entirely from its transmission system after the B2H project is constructed, PacifiCorp would transfer an ownership interest to Idaho Power in the PacifiCorp facilities that are presently used to serve BPA's SILS loads (the "asset exchange"). In addition, BPA would pay Idaho Power $10 million upon execution of the NITSAs as security for Idaho Power's construction of the B2H project to provide BPA with the NITS service. The security would allow Idaho Power to provide assurances to its regulatory bodies that its retail rate payers were insulated from risk associated with Idaho Power purchasing BPA's share of the B2H permitting interest.

Following execution of the Term Sheet, Idaho Power and BPA merged the terms for the sale of BPA's permitting interest and the NITSA security payment into a single agreement, the Purchase, Sale, and Security Agreement, because the subject matters were interrelated. The key provisions of the Purchase, Sale, and Security Agreement, NITSAs, and agreements between Idaho Power and PacifiCorp needed to serve the SILS loads are described below. If BPA's final decision is to proceed with the B2H with Transfer Service plan of service, BPA would execute these agreements concurrent with issuing the Closeout Letter.

1. Purchase, Sale, and Security Agreement

In the Purchase, Sale, and Security Agreement, BPA would transfer its permitting interest share to Idaho Power in exchange for payment to BPA for the costs BPA incurred towards permitting the B2H project (around $30 million). BPA would also pay Idaho Power the $10 million security payment. The payment for the value of the permitting interest and the security is the Purchase Price. The agreement sets forth the requirements associated with the reimbursement of the Purchase Price to address the risks and uncertainties associated with Idaho Power taking on a larger ownership share in the B2H project and constructing a major new transmission line to provide BPA with NITS service.

If Idaho Power successfully completes construction and energization of the B2H project by the milestones in the Purchase, Sale, and Security Agreement, Idaho Power would return the $10 million security to BPA within 60 days of energization of the B2H project. The remaining amount of the Purchase Price would be paid in installments based on a 20 year payment schedule. The first installment of the Purchase Price payment would begin 10 years after B2H is energized, provided that BPA takes the NITS service from Idaho Power during those 10 years. Additionally, during those 10 years of NITS service, BPA's NITS loads must reach 400 MW or more on the hour of Idaho Power's transmission system peak on a twelve-month rolling average basis. If BPA's NITS loads do not reach the 400 MW threshold during the initial 10 years of service, Idaho Power would begin repaying BPA the Purchase Price on the next year after the 400 MW threshold is met.

The Purchase, Sale, and Security Agreement also addresses reimbursement of the Purchase Price to BPA if problems arise with Idaho Power completing construction and energization of the B2H project:

- If Idaho Power does not receive the necessary governmental authorizations and, as a result, cannot complete the B2H project to provide NITS service to BPA, Idaho Power would not be obligated to pay the Purchase Price to BPA. BPA is agreeing to accept this financial risk because Idaho Power would be funding a higher percentage of B2H costs in order to provide BPA with NITS service under the B2H with Transfer Service plan of service.

- If Idaho Power does not receive governmental authorization by January of 2025, and has not commenced construction by January of 2026, or other timeline as mutually agreed to by BPA and Idaho Power, BPA would have the option to terminate the NITSAs. The option to terminate the NITSAs allows BPA to pursue an alternative plan of service for the SILS loads if there is substantial risk that the B2H project would not be completed.

    - If BPA exercises the option to terminate the NITSAs and Idaho Power ultimately receives governmental authorizations and completes the B2H project, Idaho Power would return the security to BPA and pay the remaining amount of the Purchase Price. If Idaho Power does not complete the B2H project, then Idaho Power is relieved of the obligation to pay BPA the Purchase Price.

    - If BPA does not exercise the option to terminate the NITSAs and Idaho Power ultimately completes the B2H project, then Idaho Power would pay BPA the Purchase Price based on the installment payment schedule described above.

- If Idaho Power receives all necessary governmental authorizations by January of 2025, but decides to no longer proceed with constructing and energizing the B2H project, Idaho Power would return the security to BPA. Additionally, Idaho Power must attempt to market the transferred permitting interest. Idaho Power would then pay BPA for its proportional share of the sale proceeds.

The Purchase, Sale, and Security Agreement generally reflects the deal and structure envisioned in the Term Sheet. The 400 MW limit is a new term that the parties negotiated after execution of the Term Sheet to allow Idaho Power to provide assurances to its regulatory bodies that its retail ratepayers were insulated from risk associated with Idaho Power purchasing BPA's share of the B2H permitting interest. The Term Sheet also contemplated that Idaho Power would return security amounts as credits offsetting BPA's NITSA bills. The Purchase Price payments will be independent of the NITSA billing.

2. NITS Agreements with Idaho Power

For the B2H with Transfer Service plan of service, BPA would enter into two new long-term firm NITSAs with Idaho Power. One new NITSA would provide for service to the Goshen area customers (Lower Valley, Soda Springs, Fall River, Lost River, and Salmon River) ("Goshen NITSA"). A second new NITSA would provide service for Idaho Falls ("Idaho Falls NITSA"). The Goshen and Idaho Falls NITSAs, together with the asset exchange between Idaho Power and PacifiCorp, would allow BPA to deliver energy to the SILS customers' loads from BPA's transmission system on a single leg of firm network transmission service across Idaho Power's system as opposed to relying on the conditional firm service under the interim plan of service. Finally, BPA would update three existing NITSAs that support service to BPA's Southern Idaho customers.

Service under the Goshen and Idaho Falls NITSAs would commence after two conditions precedent are satisfied. First, Idaho Power must complete construction and energization of the B2H project. Second, Idaho Power and PacifiCorp must exchange assets sufficient to enable Idaho Power to deliver resources from the BPA transmission system across the Idaho Power system on a single leg of transmission to the SILS customers' loads (see subsection 3 below). Commensurate with the asset exchange, the SILS customers' loads under the Goshen NITSA would move from the PacifiCorp Balancing Authority Area to the Idaho Power Balancing Authority Area. Arrangements for the Idaho Falls NITSA are described below.

After these conditions precedent are met, service under the Goshen and Idaho Falls NITSAs would commence upon energization of B2H, or a later date if specified by the Federal Energy Regulatory Commission (Idaho Power must obtain regulatory approval from the Commission for the NITSAs). Service under the NITSAs would terminate on July 1, 2046, and could be rolled over for additional terms consistent with Idaho Power's OATT.

The NITSAs also include an assignment provision that would allow BPA to request assignment of some or all of the service under the NITSA to the wholesale customers that are served by the NITSA. Idaho Power may not unreasonably withhold its consent to such assignment, provided the wholesale customer qualifies as an Eligible Customer consistent with Idaho Power's OATT and assumes BPA's rights and obligations under the assigned NITSA.

Idaho Falls would be served under a separate NITSA because of its unique supply arrangements with other parties. Idaho Falls currently purchases BPA's slice/block product and is responsible for managing its hourly balancing needs. Idaho Falls contracts with Utah Associated Municipal Power Systems ("UAMPS") for this balancing service, which UAMPS provides under a legacy transmission service agreement with PacifiCorp to balance the Idaho Falls load in the PacifiCorp Balancing Authority Area. Due to this unique arrangement and after discussion with Idaho Falls, BPA determined that it was reasonable to negotiate a separate NITSA for Idaho Falls. One of BPA's objectives in negotiating the Idaho Falls NITSA was to ensure that there was no impact to the existing relationship between Idaho Falls and UAMPS, or the legacy agreement between UAMPS and PacifiCorp. Accordingly, the Idaho Falls NITSA would only serve the portion of Idaho Falls load served by BPA resources.

With regard to the updates to existing NITSAs, BPA has three existing NITSAs with Idaho Power. BPA uses these NITSAs to serve 15 preference customers, including the customers in the Burley area, and to deliver reserve power to the United States Bureau of Reclamation and irrigation customers. Idaho Power has identified transmission constraints associated with serving increased loads under these NITSAs. One of the key benefits associated with the completion and energization of the B2H project is that B2H increases the capacity on Idaho Power's system that could be used to serve future load growth for these customers. After B2H is energized, these existing NITSAs would be updated to include a new B2H point of receipt that BPA can use to deliver resources from the BPA transmission system to BPA's customers located on Idaho Power's system.

3. Agreements between Idaho Power and PacifiCorp

As noted above, concurrently with BPA executing the Purchase, Sale, and Security Agreement to divest BPA of any interest in the B2H project, Idaho Power and PacifiCorp would enter into agreements for the continued funding of the B2H project, including permitting, preconstruction, and construction (with Idaho Power funding 45.45% of all further costs associated with the B2H project). Idaho Power and PacifiCorp would also enter into other agreements necessary for ownership and the ongoing operation and maintenance of the B2H project. In addition, Idaho Power and PacifiCorp would proceed with obtaining all state and federal regulatory approvals applicable to them.

With regard to the asset exchange that is a key feature of the B2H with Transfer Service plan of service, Idaho Power and PacifiCorp would enter into an agreement to transfer Goshen area assets from PacifiCorp to Idaho Power. In many instances, these assets are already jointly owned by Idaho Power and PacifiCorp, so the asset exchange would adjust the ownership share of the jointly owned facilities to increase Idaho Power's share. The asset exchange would commence upon the energization of B2H and the NITSAs between BPA and Idaho Power.

BPA is not a party to the agreements between Idaho Power and PacifiCorp. If BPA's final decision is to proceed with B2H with Transfer Service, Idaho Power and PacifiCorp would execute the contracts they would be party to concurrent with BPA executing the contracts that BPA would be party to. Questions or comments about the agreements between Idaho Power and PacifiCorp or about the permitting and construction of the B2H project should be directed to Idaho Power and PacifiCorp. For more information about Idaho Power and PacifiCorp's B2H transmission line project, please visit Boardman to Hemingway - Idaho Power.

B. Transmission Agreements with PacifiCorp and Idaho Power

Under the B2H with Transfer Service plan of service, BPA would provide PTP transmission service to PacifiCorp and Idaho Power pursuant to BPA's OATT and rate schedules. Additionally, BPA would enter into other transmission arrangements with Idaho Power and PacifiCorp related to the interconnection of the B2H project with the proposed BPA Longhorn substation. This section describes these transmission arrangements.

1. BPA providing PTP service to PacifiCorp

The 2022 Letter explained that, in consideration for PacifiCorp transferring its Goshen assets to Idaho Power, BPA and PacifiCorp would evaluate options for BPA to provide PacifiCorp with 680 MW of firm PTP service at or near the 230kV side of the Ponderosa substation (Ponderosa 230) in central Oregon. BPA's evaluation would be consistent with BPA's OATT and business practices and would consider a 2021 joint study. The preferred option included conversion of PacifiCorp's legacy bidirectional scheduling rights over BPA's Buckley-Summer Lake line to PTP service. The transmission capacity associated with the conversion would be combined with

PacifiCorp requesting to redirect existing PTP service. PacifiCorp would pay for the PTP service pursuant to BPA's OATT and posted transmission rates. The second, back-up, option involved changes to how PacifiCorp scheduled the legacy bidirectional scheduling rights with other limitations.

As noted above, the Term Sheet provided that BPA's evaluation would take into consideration a 2021 joint study performed by BPA, Idaho Power, and PacifiCorp as well as two series capacitor projects identified in the study that Idaho Power and PacifiCorp intended to install. For one of the projects, Idaho Power and PacifiCorp would install a series capacitor around the midpoint of the B2H line and develop a remedial action scheme ("Midline Series Capacitor Project"). For the other project, PacifiCorp would upgrade the existing series capacitor at the Meridian substation or install an electrically equivalent series capacitor ("Meridian Series Capacitor Project"). The joint study demonstrated that these series capacitor projects would improve performance of the transmission system with B2H in service and would allow BPA to accommodate the PTP service PacifiCorp sought as compared to the existing system configuration. The Midline and Meridian Series Capacitor Projects enhance system stability and allow flows to be shifted from more constrained transmission facilities to less constrained parallel facilities. Both of these factors help to optimize the utilization of the overall transmission system. The 2021 joint study provides useful information, but does not serve as a replacement for PacifiCorp submitting transmission requests and BPA evaluating those requests consistent with BPA's OATT and applicable business practices. Therefore, the Term Sheet specified that PacifiCorp would need to submit transmission service requests so that BPA could do the OATT evaluation.

Following execution of the Term Sheet, BPA and PacifiCorp aligned on the details for the PTP redirect requests that would be paired with the conversion of the legacy scheduling rights under the preferred option. The second, back-up option was determined to be unworkable and did not receive further consideration. In April and June, 2022, PacifiCorp submitted the PTP redirect requests over BPA's OASIS. The following table describes the requests:

Parent (Existing) Reservation	**Redirect Reservation**
70 MW from Garrison 500 to Buckley 500	70 MW from Garrison 500 to Ponderosa 230
70 MW from McNary 230 to Buckley 500	70 MW from McNary 230 to Ponderosa 230
200 MW from Big Eddy 500 to Buckley 500	200 MW from Big Eddy 500 to Ponderosa 230
120 MW from Ponderosa 500 to Ponderosa 230	120 MW from Summer Lake 500 to Ponderosa 230
190 MW from Ponderosa 500 to Pilot Butte 230	190 MW from Summer Lake 500 to Pilot Butte 230
30 MW from Ponderosa 500 to Pilot Butte 230	30 MW from Summer Lake 500 to Pilot Butte 230

BPA evaluated the redirect requests consistent with its OATT and the standard evaluation processes, which are described in BPA's business practices including the Transmission Service Request Evaluation Business Practice. BPA's standard evaluation processes take into consideration existing obligations and higher queued requests. BPA evaluated the availability of capacity to accommodate the conversion of the scheduling rights to PTP service based on the existing bidirectional capacity over the Buckley-Summer Lake line that PacifiCorp has been scheduling under the legacy contract (340 MW in the north-to south direction and 340 MW in the south-to-north direction). In order to pair the conversion with the redirect requests, BPA applied this bidirectional capacity to the redirected service. BPA then considered whether there were other impacts to the transmission system not reflected in the redirect and conversion analysis. Finally, BPA's consideration took into account the 2021 joint study and the installation of the series capacitor projects.

BPA concluded that the PTP service (the preferred option) can be accommodated with stipulations that are consistent with the Term Sheet. The PTP stipulations include the energization of the B2H project to include the Midline Series Capacitor Project, the installation of the Meridian Series Capacitor Project pursuant to a construction agreement between PacifiCorp and BPA, the transfer of the Goshen area assets between PacifiCorp and Idaho Power, and the commencement of BPA's Goshen and Idaho Falls NITSAs with Idaho Power.

Accordingly, BPA is proposing to execute several agreements with PacifiCorp concurrent with the issuance of the final decision in the Closeout letter. The PTP agreements with PacifiCorp reflect the service shown in the Redirect Reservation column of the table above and include conditions precedent to reflect the PTP stipulations. After the conditions precedent have been met, the service would commence upon energization of B2H. BPA also would execute an amendment to the legacy agreement with PacifiCorp to remove PacifiCorp's bidirectional scheduling rights upon commencement of the PTP service (as noted, this amendment reflects the conversion to the PTP service). PacifiCorp is required to file the amendment to the legacy agreement with the Commission for approval. Finally, BPA would execute a construction and coordination agreement with PacifiCorp which sets forth PacifiCorp's obligations to design, coordinate with BPA, and install at its sole expense the Meridian Series Capacitor Project.

Following the February 8, 2022 workshop, several stakeholders asked how the proposed PacifiCorp transmission service would affect the constrained transmission system in central Oregon. Customers also asked whether BPA was considering additional upgrades in central Oregon as part of the B2H negotiations and, if so, whether there was an opportunity for BPA's customers to share the costs and benefits for those upgrades. As BPA explained in its April 1, 2022, response to the workshop comments, the conversion paired with the redirected service does not affect the transmission service BPA provides to other customers in central Oregon. As described above, BPA evaluated the service consistent with its business practices which take into account existing obligations and higher queued requests. Further, the 2021 joint study undertaken by BPA, PacifiCorp, and Idaho Power identified the Midline and Meridian Series Capacitor Projects as upgrades that would improve system performance with B2H in service. However, these projects and the B2H project do not increase the capacity available to BPA's other customers in central Oregon.

2. BPA providing PTP Service to Idaho Power

The 2022 Letter explained that, in lieu of a previously considered asset exchange between BPA and Idaho Power under the B2H with Asset Swap proposal, Idaho Power would acquire 500 MW of PTP service from BPA for delivery of northwest resources to the B2H connection at the proposed BPA Longhorn substation. Before execution of the Term Sheet, Idaho Power submitted a transmission request seeking this service. BPA evaluated the request as part of the 2021 TSEP Cluster Study. Following the study, BPA determined that the request could be accommodated with stipulations. The stipulations include the energization of the B2H project and the interconnection of the B2H project to the proposed BPA Longhorn substation (see subsection 3 for discussion about the proposed B2H interconnection). Idaho Power would pay for the PTP service pursuant to BPA's OATT and posted transmission rates. BPA is proposing to execute the PTP agreement with conditions precedent reflecting these stipulations concurrent with the issuance of the final decision in the Closeout letter.

3. B2H Interconnection to the Proposed BPA Longhorn Substation

The northern terminus for the B2H project and the point of interconnection with BPA's system would be BPA's proposed Longhorn substation near Boardman, Oregon. The 2022 Letter explained that to facilitate the B2H interconnection at the proposed BPA Longhorn substation, BPA, Idaho Power, and PacifiCorp would develop line and load interconnection and related funding and construction agreements. In February of 2022, Idaho Power as project manager for the B2H project, submitted a line and load interconnection request (L0515) for the B2H interconnection. BPA is currently studying this request, which will include environmental review, and intends to offer additional agreements and make decisions on design, advance funding, and construction in accordance with BPA's line and load interconnection business practice.

BPA is not making a final decision to construct the proposed Longhorn substation as part of B2H with Transfer Service decision. Prior to Idaho Power's B2H interconnection request L0515, Umatilla Electric Cooperative ("UEC") submitted a load interconnection request (L0482) ("UEC project") and the construction of the proposed Longhorn substation has been identified as a need for the UEC project. At this time, the UEC project is further along in the study process than the proposed B2H interconnection. BPA has completed the technical studies for the UEC request and is currently in the process of completing environmental review of the potential impacts to the human and natural environments (*e.g.*., physical, biological, and cultural resources) under NEPA. The NEPA documentation for the UEC interconnection request will be made available to the public on BPA's website. After BPA completes the environmental studies, which is expected in February, 2023, BPA will make a final decision about the construction of the Longhorn substation in response to the UEC interconnection request. Accordingly, BPA's decision to construct the proposed Longhorn substation would be in response to the UEC request and would not be driven by the final decision for the B2H with Transfer Service plan of service.

While BPA's final decision to construct the Longhorn substation will be in response to the UEC request and not the B2H with Transfer Service plan of service, BPA would design the proposed Longhorn substation to accommodate the B2H interconnection request and other future interconnection requests. Equipment specific to the UEC project and the B2H interconnection request, such as an additional 500 kV terminal for the proposed B2H interconnection, 500/230 kV transformers, and a 230 kV yard for the UEC project, would be designed, funded, and developed in accordance with BPA's line and load interconnection business practice. BPA anticipates allocating advance funding responsibilities between the UEC project and the B2H interconnection in accordance with BPA's line and load interconnection business practices. Consistent with the Term Sheet in recognition of the benefits exchanged, BPA would require advance funding from the B2H project, subject to repayment through transmission credits on OATT service, for costs associated with the B2H interconnection at the proposed BPA Longhorn substation.

4. Removal of a segment of BPA's Boardman-to-Ione transmission line

A portion of BPA's Boardman-to-Ione 69-kV transmission line is located in a right-of-way crossing the U.S Navy's ("Navy") Naval Weapons Systems Training Facility Boardman Property in Umatilla County, Oregon. BPA uses this line to serve Columbia Basin Electric Cooperative, Inc. ("Columbia Basin"). Idaho Power and PacifiCorp need a segment of this right-of-way for B2H construction. For B2H to be constructed on the right-of-way, BPA's Boardman-Ione transmission line must be removed first. Additionally, BPA would need to find an alternative to serve Columbia Basin.

In 2019, BPA decided to enter into an amended Boardman-to-Ione transmission line land use agreement with the Navy to allow for the removal of the line from the Navy property so that the B2H project could repurpose a segment of the right-of-way, with the remaining segment to be removed to the benefit of cultural and natural resources in the area. See Bonneville Power Administration, Record of Decision, Boardman-to-Ione 69kV Transmission Line (May 13, 2019), *available at* https://www.bpa.gov/-/media/Aep/efw/nepa/active/boardman-to-hemingway/board-ione-lua-nepa-rod-05-13-2019-final.pdf. BPA's decision was contingent on multiple considerations, including BPA entering an agreement with Idaho Power and PacifiCorp to ensure that BPA would be reimbursed in full for all costs associated with removing the Boardman-to-Ione line and providing an alternative to service Columbia Basin's load. In the event the B2H project is not constructed, BPA will retain its right-of-way on the Navy property.

On March 18, 2020, BPA, Idaho Power, and PacifiCorp executed an agreement for PacifiCorp and Idaho Power to pay or reimburse BPA for its costs associated with removing and replacing the Boardman-to-Ione line if the B2H project is constructed. BPA's costs include providing replacement service for Columbia Basin's loads, which would include studies and design, environmental review, building a step down substation, tap line and tap, and other necessary construction or reconfigurations to accommodate the removal. These reimbursement commitments were acknowledged in the section of the Term Sheet describing Idaho Power and PacifiCorp's intent for the B2H construction funding agreement. The commitments have also been incorporated into agreements with Idaho Power, as project manager for B2H, associated with BPA's removal and replacement of the Boardman-to-Ione line.

With regard to BPA finding an alternative to serve Columbia Basin, BPA intends to request transmission service from UEC to serve Columbia Basin's load. As an initial step, BPA has submitted a line interconnection request to UEC. This request starts the process for BPA to construct a new step down substation and transmission facilities to connect the UEC end point of service to Columbia Basin's system. At this time, BPA is siting, designing, and studying these proposed facilities. As planning progresses, BPA would conduct environmental review of the potential impacts to the human and natural environments that could be expected from implementing the Boardman-to-Ione line relocation. As noted above, pursuant to the March 18, 2020, agreement, BPA will recover costs associated with the Boardman-to-Ione line relocation from PacifiCorp and Idaho Power. Energization of the proposed alternative service would need to be completed by spring of 2025, to allow time to remove the old line and build the new B2H line by spring of 2026.

5. Operational agreement with Idaho Power and PacifiCorp

The 2022 Letter described BPA, Idaho Power, and PacifiCorp's intent to develop an operational agreement covering various facilities and agreements that affect Path 14 (Idaho to Northwest, the WECC transmission path that will include B2H), Path 75 (Hemingway-Summer Lake 500kV), and the Northwest AC Intertie. Following execution of the Term Sheet, BPA, PacifiCorp, and Idaho Power prioritized negotiation of the contracts described above. Negotiation of the operational agreement will begin this winter.

C. Assignment Agreement with PacifiCorp

The 2022 Letter explained that BPA currently purchases 200 MW of conditional firm PTP service from Idaho Power to wheel power over Idaho Power's system for ultimate delivery to SILS customers on PacifiCorp's system. With the construction of the B2H project, the NITSAs, and associated asset exchanges between Idaho Power and PacifiCorp, BPA will no longer need to procure these conditional firm PTP services. The 2022 Letter described BPA's intent to assign its conditional firm PTP service agreements on Idaho Power's system to PacifiCorp, subject to certain stipulations. Prior to the assignment, BPA would submit redirect requests to the points of receipt and points of delivery selected by PacifiCorp. PacifiCorp would be responsible for all costs associated with the redirect and assignment. This redirect and assignment is to PacifiCorp's benefit for the B2H deal, but would not result in any increased costs to BPA.

Following execution of the Term Sheet, BPA and PacifiCorp negotiated a Letter Agreement setting out the terms for the future redirect and assignment of BPA's conditional firm PTP service. BPA is proposing to execute the Letter Agreement concurrent with issuing the final decision in the Closeout Letter. Pursuant to the Letter Agreement, BPA would submit redirect requests pursuant to Idaho Power's OATT for the two conditional firm service agreements on Idaho Power's system. BPA would request the redirected service to commence following the energization of B2H and commencement of BPA's NITSAs with Idaho Power. PacifiCorp would reimburse BPA for all study costs and fees assessed by Idaho Power.

Following Idaho Power's evaluation of the redirect requests, PacifiCorp would determine if the redirected service, including any conditions Idaho Power might assess, is acceptable to PacifiCorp. If the service is acceptable to PacifiCorp, then BPA would confirm the requests and assign the redirected reservations to PacifiCorp. If PacifiCorp determined that the redirected service was not acceptable, then BPA would withdraw the requests and, if directed by PacifiCorp, submit alternative redirect requests. If B2H is energized and BPA's NITSAs have commenced but PacifiCorp has not yet accepted assignment of the conditional firm PTP service agreements, PacifiCorp would reimburse BPA for all rates and charges that Idaho Power assesses to BPA for the two 100 MW conditional firm PTP service agreements, until such time as the service is assigned to or waived by PacifiCorp.

III. Business Case for the B2H with Transfer Service Plan of Service

The 2022 Letter described BPA's business case for the B2H with Transfer Service plan of service at a high level, noting that the proposal would provide a firm, stable, and long-term transmission path to deliver resources from the BPA transmission system to the SILS customers' loads at an economical cost. During the February 8, 2022, workshop, BPA explained that the estimated benefits of B2H with Transfer Service is a 35% to 52% improvement in net present value ("NPV") over the interim plan of service. Now that contract negotiations are complete, BPA has updated the assumptions in the business case. This letter provides an overview of BPA's business case.

Quantitatively, BPA analyzed the costs associated with the B2H with Transfer Service plan of service and the current interim plan of service using a NPV methodology over a 30-year horizon and with a discount rate of 2.81%. Notably, there are significant uncertainties associated with the assumptions used for a 30-year period. Therefore, BPA evaluated numerous rate, cost, and revenue assumptions to determine a range of cost savings that could be expected over a 30-year period. On average over 30 years, the B2H with Transfer Service plan of service yields an estimated cost of around $520 million. Over that same time period, the continuation of the current interim plan of service yields an estimated cost of around $1.24 billion. Accordingly, the B2H with Transfer Service provides an estimated $720 million of cost savings as compared to the interim plan of service.

Each of the scenarios evaluated in the business case includes significant complexity, with many factors driving cost, savings, and relative value. However four primary drivers account for the majority of the significant financial benefit associated with the B2H with Transfer Service plan of service over the current interim plan of service. First, the B2H with Transfer Service plan of service eliminates the need to acquire two legs of transmission that BPA currently uses to serve the SILS customers' loads. Eliminating one leg of transmission yields an expected value of approximately $250 million in cost savings over the 30-year period.

Second, Idaho Power is expected to have lower rates for NITS as compared to PacifiCorp's rates for NITS under the interim plan of service. As such, taking NITS from Idaho Power is expected to have a lower cost compared to the PacifiCorp NITS costs BPA anticipates if BPA were to continue the current interim plan of service. BPA's analysis of Idaho Power's expected rates took into account projected increases following its construction of B2H, as well as the implications of such rate increases on BPA's costs under the existing NITSAs for service to

BPA's other preference customers in southern Idaho. The NITS service from Idaho Power is expected to yield approximately $190 million in cost savings over the 30-year period.

Third, BPA expects $45 million in lower overall Energy Costs over the 30-year period by reducing BPA's reliance on market power in the vicinity of the SILS customers.

Lastly, the B2H with Transfer Service plan of service yields incremental revenue for BPA associated with 500 MW of PTP service that BPA would provide to Idaho Power. This PTP service is estimated to yield an expected value of approximately $200 million in revenue over a 30-year period.

BPA also expects $40 million in the recovery of sunk cost (the sunk cost is the Purchase Price for the sale of BPA's permitting interest, which includes the payment of the $30 million BPA incurred towards permitting plus the $10 million security). BPA anticipates the costs associated with purchasing transmission service from UEC to serve Columbia Basin's load to be modest.

In addition to these quantitative financial benefits, BPA expects other substantial benefits. As noted above, BPA's current interim plan of service relies on a leg of transmission over Idaho Power's system that is "conditional firm" PTP service. Conditional firm PTP service is a type of transmission service that can be curtailed more readily under certain system conditions. The conditions associated with this service are reviewable by Idaho Power every two years, increasing the risk of additional conditions for curtailment of BPA's PTP service over time. With Idaho Power's construction of B2H, BPA would receive long-term firm network transmission to serve its southeast Idaho loads. Network transmission is redispatched rather than curtailed like PTP, substantially reducing BPA's risk of service to its loads.

Additionally, the increase in transmission capacity across Idaho Power's system from the construction of B2H would enhance BPA's ability to serve its other existing preference customers currently served by NITSAs over Idaho Power's transmission system. BPA uses these existing NITSAs to serve 13 preference customers in the Burley, Idaho area, Oregon Trail Electric Cooperative in eastern Oregon, and the City of Weiser in western Idaho. BPA also uses an existing NITSA to deliver reserve power from the federal system to the United States Bureau of Reclamation and irrigation customers. The completion of the B2H project would create capacity on Idaho Power's system that could be used to serve the load growth of these existing customers. Accordingly, potential transmission system congestion on federal power deliveries to these customers over Idaho Power's system would be alleviated.

The B2H with Transfer Service plan of service also reduces BPA's reliance on market power in the vicinity of the SILS customers. The current interim plan of service has BPA sourcing market power from the desert Southwest, which carries with it resource adequacy considerations and negative implications for the carbon content of BPA's fuel mix. Reduced market reliance alleviates these negative effects and generally reduces BPA's cost risk in a region where resource retirements loom and BPA has already observed reduced liquidity.

Additionally, while providing PacifiCorp with PTP service in central Oregon would not result in additional revenues for BPA because it reflects the redirect of existing PTP service that

PacifiCorp currently pays for, that aspect of the B2H with Transfer Service arrangement works to achieve BPA's strategic objectives of converting legacy service to standard OATT service. Idaho Power and PacifiCorp would also fund the series capacitor projects that improve system performance when B2H is in service. Lastly, the B2H with Transfer Service plan of service avoids the complexities and complications of joint ownership and asset swaps originally considered in the B2H with Asset Swap proposal (a description of the B2H with Asset Swap proposal was provided in the 2022 Letter).

IV. Public Process and Next Steps

BPA is proposing to proceed with the B2H with Transfer Service plan of service and execute binding contracts with Idaho Power and PacifiCorp. Public participation and input on the B2H with Transfer Service plan of service is important to BPA. Before BPA makes a final decision, BPA is seeking public comment through February 9, 2023. Comments should be submitted here. BPA will hold a workshop to answer questions about the B2H with Transfer Service plan of service on January 23, 2023. Please find details of that workshop here. BPA is also conducting appropriate NEPA processes. If BPA decides to proceed, BPA will issue a Closeout letter to the region on or about March 23, 2023, describing its reasoning and responding to comments.

If BPA's final decision is to proceed, BPA would execute the Purchase, Sale, and Security Agreement, the two NITSAs with Idaho Power, the PTP agreements and other related transmission agreements with PacifiCorp and Idaho Power, and the Letter Agreement with PacifiCorp concurrent with issuing the Closeout letter to the region. The decision to execute agreements associated with the proposed B2H interconnection to the BPA Longhorn substation and the removal and replacement of BPA's Boardman-to-Ione transmission line would be in accordance with BPA's line and load interconnection processes.

Docket No. 20000-___-EN-23
Witness: Rick T. Link

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Direct Testimony of Rick T. Link

February 2023

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company").

A. My name is Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Senior Vice President, Resource Planning, Procurement and Optimization.

Q. Please describe the responsibilities of your current position.

A. I am responsible for PacifiCorp's energy supply management and resource planning and procurement functions, which includes the integrated resource plan ("IRP"), structured commercial business and valuation activities, and long-term load forecasts. Most relevant to this docket, in coordination with Company witness Mr. Rick A. Vail, I am responsible for contract negotiations required for PacifiCorp's participation in the Boardman-to-Hemingway project ("B2H" or the "Project"). I am also responsible for the economic analysis of B2H.

Q. Please describe your professional experience and education.

A. I joined PacifiCorp in December 2003 and assumed the responsibilities of my current position in September 2021. Over this period, I held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities, developing financial models to evaluate resource and transmission investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I was responsible for delivering PacifiCorp's 2013, 2015, 2017, 2019, and 2021 IRPs; have been directly involved in implementing and overseeing resource request for proposal ("RFP") processes; and performed economic analysis supporting a range of resource and transmission investment opportunities. Before joining PacifiCorp, I was an energy and environmental economics consultant with ICF Consulting (now ICF International) from 1999 to 2003, where I performed electric sector financial modeling of environmental policies and resource investment opportunities for utility clients. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Master of Environmental Management degree from Duke University in 1999.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in proceedings before the Wyoming Public Service Commission ("Commission"), the Utah Public Service Commission, the Idaho Public Utilities Commission, the Public Utility Commission of Oregon, the Washington Utilities and Transportation Commission, and the California Public Utilities Commission.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. My testimony supports the Company's application for waiver or approval of a non-situs certificate of public convenience and necessity ("CPCN") for Energy Gateway Segment H, the Boardman to Hemingway 500-kilovolt ("kV") transmission line ("B2H" or the "Project"). My testimony also supports waiver or approval under the advanced review process set forth in the stipulation approved in Docket No. 20000-384-ER-10, Record No. 12702 ("Advanced Review Process").

I present and explain the economic analysis that supports PacifiCorp's request for waiver or a non-situs CPCN for B2H. I explain how B2H and related changes to

PacifiCorp's transmission system and operations were analyzed and shown to be cost effective in PacifiCorp's 2021 IRP and 2021 IRP Update, and provide current economic analysis demonstrating customer benefits associated with the Project.

Q. Please summarize your direct testimony regarding B2H.

A. As the economic analysis in my testimony demonstrates, B2H is necessary, reasonable, and in the public interest. The 2021 IRP and 2021 IRP Update showed that B2H is necessary to meet the Company's need to reliably and cost effectively serve customers, and it was part of the preferred portfolio in both plans. Both the 2021 IRP and 2021 IRP Update specifically examined the portfolio impacts and system cost implications of not participating in B2H relative to the preferred portfolio outcome that included it. Both analyses showed that building B2H was the least-cost, least-risk outcome. In the 2021 IRP, B2H was projected to result in $453 million in risk-adjusted net benefits during the study horizon of 2021 through 2040.[1] Similarly, the 2021 IRP Update projected risk-adjusted net benefits of $439 million during the same period.[2]

Since the 2021 IRP Update was prepared, several key changes have occurred. First, the Company's most recent load forecast has significantly increased, reflecting both new load and the impact of climate change. Second, the United States Environmental Protection Agency ("EPA") proposed its "Ozone Transport Rule" (also called the "Good Neighbor Rule" or "Cross-State Air Pollution Rule") to establish allowance-based emissions limits for nitrogen oxides ("NOx") that will impact

[1] PacifiCorp's 2021 Integrated Resource Plan. Volume I. September 1, 2021. Pg. 271-272. Available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

[2] PacifiCorp's 2021 Integrated Resource Plan Update. March 31, 2022. Pg. 89-91. Available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021_IRP_Update.pdf

PacifiCorp's thermal resources in Utah and Wyoming. Third, the enactment of the federal Inflation Reduction Act ("IRA") has extended and expanded tax incentives for clean generation and energy storage resources. Finally, PacifiCorp's transmission service requirements have evolved considering that the Bonneville Power Administration ("BPA") may be unable to reasonably accommodate some of the modifications to PacifiCorp's existing transmission service arrangements contemplated in the non-binding B2H term sheet, dated January 18, 2022, attached as RMP Exhibit 3.1 to my testimony.[3] After incorporating these and other associated changes, B2H is now projected to result in $1.713 billion in risk-adjusted net benefits during a study horizon of 2023 through 2042, assuming medium natural gas and carbon prices.

The Project significantly enhances the capability of the regional electric grid, and the current B2H benefit estimate has three distinct aspects. First, B2H will increase the bidirectional transfer capability between PacifiCorp's east and west balancing authority areas ("BAA"). Second, B2H enables lower-cost and more reliable transmission service to PacifiCorp's central Oregon loads. Third, B2H allows for lower cost transmission service to PacifiCorp loads in the vicinity of BPA's planned Longhorn substation, which is the western terminus of B2H.[4]

In the Company's economic analysis, PacifiCorp evaluated the change in revenue requirement associated with B2H using the PLEXOS model under a range of natural gas price and carbon dioxide ("CO_2") policy assumptions ("price-policy scenarios"). PacifiCorp calculated the change in system revenue requirement between

[3] The term sheet is also available at: https://docs.idahopower.com/pdfs/B2H/B2H-termsheet-bpapacIPCSigned-IP.pdf

[4] The Longhorn substation is approximately four miles east of the city of Boardman, Oregon.

cases with and without B2H, where capital revenue requirement is levelized.

The change in annual nominal revenue requirement through 2042 was also calculated to provide some perspective around potential rate pressures relative to a case that does not include B2H.

The Company requests that the Commission grant the requested waivers or issue a non-situs CPCN for B2H, along with Advanced Review approval, no later than the end of June 2023 to ensure timely energization for this critical transmission system upgrade.

III. OVERVIEW OF B2H

Q. Please describe B2H.

A. B2H is a high voltage single-circuit 500-kV alternating current transmission line that extends approximately 300 miles from north-central Oregon to southwest Idaho. In the context of PacifiCorp's long-term transmission plan, B2H is also referred to as Segment H of Energy Gateway.

Q. Is the Company the only party involved in B2H?

A. No. Idaho Power Company ("IPC") is the overall project manager, responsible for all B2H permitting, design, procurement, and construction. IPC will fund and own 45.45 percent of B2H and the Company will fund and own 54.55 percent of B2H. BPA has also partnered with IPC and the Company in the development of B2H. However, BPA will not have an ownership interest in B2H and instead intends to acquire B2H capacity from IPC through transmission service agreements.

IV. 2021 INTEGRATED RESOURCE PLAN

Q. Does the 2021 IRP identify a need for additional resources and transmission to serve PacifiCorp's customers?

A. Yes. The primary focus of any IRP is to forecast customer demand and to evaluate different combinations of resources and transmission to meet that customer demand over time. In the 2021 IRP, the preferred portfolio represents the least-cost, least-risk portfolio of resources and transmission options, as presented in Tables 9.16 and 9.17 in Chapter 9 of Volume I. Consistent with prior IRPs, in the 2021 IRP, all resource portfolios that were considered as candidates for the preferred portfolio contain new supply-side, demand-side, market resources, and transmission upgrades necessary to meet customer demand.

Q. Was B2H included in the 2021 IRP preferred portfolio?

A. Yes. In the 2021 IRP, after a variety of price-policy and coal retirement scenarios were considered, the P02-MM[5] portfolio was identified as top-performing and B2H was included in that portfolio. At that point, eight variants of P02-MM were prepared to analyze key resource and transmission decisions. As B2H was already part of the P02-MM portfolio, a "No B2H" portfolio was prepared that excluded B2H. The P02-MM portfolio, which includes B2H, was identified as the top-performing portfolio among all variants, including the variant that removed B2H.[6]

[5] In the 2021 IRP, the P02 series of portfolios reflect fully optimized coal unit retirements using the best available input data and assumptions regarding requirements and constraints. The P02-MM portfolio was selected assuming medium gas prices and a medium CO_2 price proxy for future federal policy.

[6] The 2021 IRP also identified additional resources related to compliance with Washington's Clean Energy Transformation Act ("CETA") that were added to establish the 2021 IRP preferred portfolio (P02-MM-CETA). The additional resources necessary to comply with CETA, however, are not treated as system resources for purpose of the IRP and had no impact on the need for B2H.

Q. Did the 2021 IRP modeling account for the interdependence of resources and transmission, like B2H?

A. Yes. The PLEXOS model used to develop the 2021 IRP, which I discuss in more detail below, has the ability to endogenously view costs and transmission capability associated with transmission upgrades and allows for selection of specific transmission investments that coincide with new resource options. Endogenous transmission modeling capabilities in the PLEXOS model include the consideration of 1) new incremental transmission options tied to resource options; 2) existing transmission rights tied to the use of post-retirement brownfield sites; 3) estimated costs associated with these transmission options; and 4) transmission options that interact with multiple or complex elements of the IRP transmission topology. When the 2021 IRP modeling evaluated transmission investments, it accounted for the assumed cost for those investments and the value generated by those investments by enabling low-cost resource options and better optimization of resources needed to serve load or to lower system costs.

Q. Please describe the reliability benefits from B2H that were identified in the 2021 IRP.

A. The 2021 IRP indicated that energy not served ("ENS") would be slightly higher in the absence of B2H. ENS is reported as an output of the PLEXOS model and it indicates the volume of load that could not be met do to a shortfall of supply in modeled load areas across PacifiCorp's system.

Q. Does the 2021 IRP fully capture the expected system reliability benefit associated with B2H?

A. No. The 2021 IRP reflects PacifiCorp's load, resources, and transmission rights, plus limited access to market purchases. In light of regional reliability concerns, discussed in Chapter 5 of the 2021 IRP, the maximum amount of market purchases available was reduced significantly from the level in the 2019 IRP. These reductions were applied in the summer season for the California-Oregon Border ("COB"), Nevada-Oregon Border ("NOB"), and Mona markets whose participants typically experience peak demand in the summer. For the Mid-Columbia ("Mid-C") market, the maximum amount of market purchases was reduced in both seasons, but by a larger amount in the winter season, as the Pacific Northwest is generally winter peaking. By enhancing the connection between the summer and winter-peaking areas of PacifiCorp's system, B2H will make it more likely that purchases can be procured from markets that are not experiencing peak conditions and delivered where they are needed (i.e., purchases imported to PacifiCorp's East BAA in the winter and purchases imported into PacifiCorp's West BAA in the summer). While modeled market purchase limits are representative of what might be available during peak demand conditions, there are many hours within summer and winter seasons in which regional demand is likely to support market transactions well in excess of those limits. Due to the market purchase limits, the reported results do not account for the entire improvement in reliability that B2H is likely to facilitate by providing additional access to distant markets.

Q. Will B2H increase PacifiCorp's reliance on market purchases?

A. No. Access to market purchases is not the same as reliance on market purchases. The

P02-MM portfolio, which includes B2H, has more resources as a result of higher interconnection capability provided by the Project. The addition of more resources generally reduces the need to rely on market purchases to serve customer load. This does not mean that market purchases will necessarily decline, as reduced congestion allows for more cost-effective market purchases to support customer load rather than more expensive dispatchable resources. To the extent dispatchable resources are called upon less often, but remain available as indicated by the increase in resources in the portfolio that includes B2H, PacifiCorp would not be reliant upon such purchases to meet its peak loads and reliability requirements.

V. 2021 IRP UPDATE

Q. Has the Company prepared an update to the 2021 IRP?

A. Yes. On March 31, 2022, the Company issued its 2021 IRP Update.

Q. What is the purpose of the 2021 IRP Update?

A. The 2021 IRP Update serves as a checkpoint to the action plan contained in the 2021 IRP to ensure that changes in the planning environment are considered in between the full IRP planning process, which is completed every two years. The 2021 IRP Update assesses whether evolving trends and events that may ultimately impact customers merit a shift in the action plan to deliver resources and transmission investments that might be needed to reliably serve customers. As relevant here, the 2021 IRP Update reflects resource planning and procurement activities that have occurred since the 2021 IRP and presents an updated load-and-resource balance and an updated resource portfolio consistent with changes in the planning environment.

Q. Was B2H considered in the Company's 2021 IRP Update?

A. Yes. B2H and associated resource interconnections it will enable were included in the preferred portfolio identified in the 2021 IRP Update.

Q. Did the 2021 IRP Update continue to show a need for additional transmission resources?

A. Yes. In fact, the need increased relative to the 2021 IRP, primarily due to an increase in forecasted load. While the same transmission options were available in the 2021 IRP Update as the 2021 IRP, the 2021 IRP Update included two new options and accelerated four others from the 2021 IRP.[7] This was partially offset by one delay and the removal of one option from the final year of the study horizon. There were no changes in the timing and need for B2H.

Q. Did the 2021 IRP Update continue to show a need for additional generation resources?

A. Yes. The resource need also increased due to an increase in forecasted load. The 2021 IRP Update shows a resource need in all years of the planning horizon—starting at 1,584 MW in 2022 and increasing to 6,755 MW in 2040.[8] In 2027, the first full year that B2H will be in service, the resource need is 2,403 MW, an increase of 273 MW, or approximately 13 percent, relative to the resource need identified in the 2021 IRP. The higher load reflected in the 2021 IRP Update approaches the level analyzed in the high-load sensitivity conducted in the 2021 IRP.[9] And, as discussed later in my

[7] *See* 2021 IRP Update, Table 6.2.
[8] *See* 2021 IRP Update, Table 4.2.
[9] *See* 2021 IRP Update, Pg. 2.

testimony, the most recent load forecast is even higher than what was assumed in the 2021 IRP Update.

Q. What other important updates were included in the 2021 IRP Update modeling?

A. As discussed in Chapter 5 – Modeling and Assumptions Updates of the 2021 IRP Update, key updates in addition to the load-and-resource balance include the resource changes due to activity resulting from the 2020 All Source RFP. Importantly, the EPA's pre-publication version of its Ozone Transport Rule, which was released on March 11, 2022, was not modeled in the 2021 IRP Update.

Q. Did the 2021 IRP Update include the same with-and-without B2H analysis that you describe for the 2021 IRP?

A. Yes. Through 2040, the resource portfolio with B2H was $439 million lower cost on a risk-adjusted basis as compared to the portfolio without B2H.

VI. MODELING ASSUMPTIONS

Q. Please summarize the natural gas and CO_2 price assumptions used in the updated economic analysis of B2H in this case.

A. The updated economic analysis of B2H includes four price-policy scenarios, as summarized in Table 1:

- Medium natural gas prices paired with medium CO_2 prices, which I refer to as the "MM" price-policy scenario;
- Medium natural gas prices without a CO_2 price, which I refer to as the "MN" price-policy scenario;
- Low natural gas prices without a CO_2 price, which I refer to as the "LN" price-policy scenario; and

- High natural gas prices with a high CO_2 price, which I refer to as the "HH" price-policy scenario.

These assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect net power cost ("NPC") benefits, non-NPC variable-cost benefits, and system fixed-cost benefits associated with B2H. Because wholesale-power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. Table 1 summarizes the price-policy scenarios used to analyze B2H.

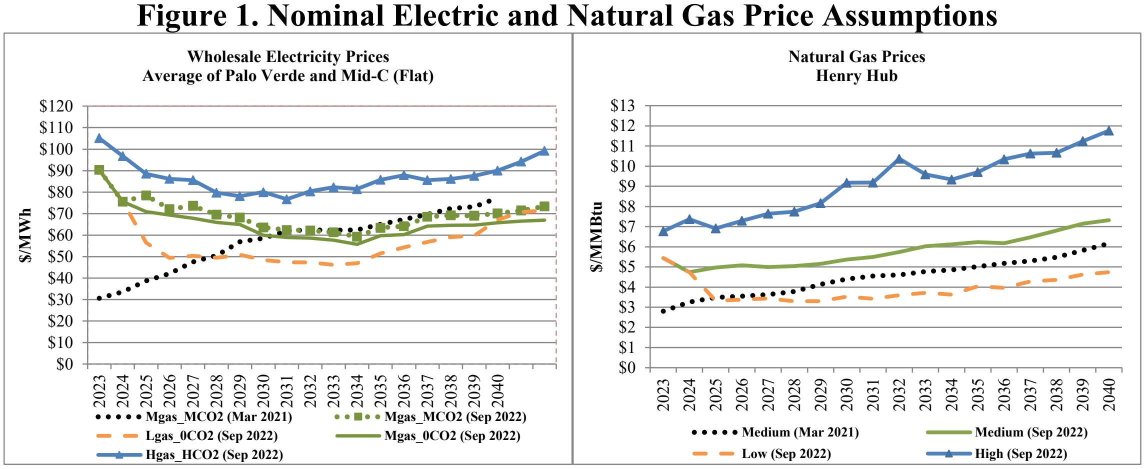
Table 1. Price-Policy Scenario Assumption Overview

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
MM	Medium Gas: $5.67	$12.10/ton starting 2025 rising to $51.40/ton in 2040
MN	Low Gas: $3.67	None
LN	Medium Gas: $5.67	None
HH	High Gas: $8.94	$44.34/ton starting 2025 rising to $120.48/ton in 2040
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. Please describe the natural gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's official forward price curve ("OFPC") dated September 30, 2022, which was the most current OFPC available when PacifiCorp prepared its modeling inputs. The first 36 months of the OFPC reflect market forwards at the close of a given trading day (September 30, 2022, in this case). As such, these 36 months represent market forwards as of September 2022. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by a third-party using AURORAXMP ("Aurora"), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. Figure 1 shows Henry Hub natural-gas price assumptions for the medium, high, and low natural gas price scenarios compared to the medium price used in the 2021 IRP forecast from March 2021. The electric prices comparison is also shown. The September 2022 price forecast reflects updates to natural gas prices that are higher in the near term from recent market price trends. The updated gas prices also account for limitations in west coast states to add new natural gas.

Figure 1. Nominal Electric and Natural Gas Price Assumptions

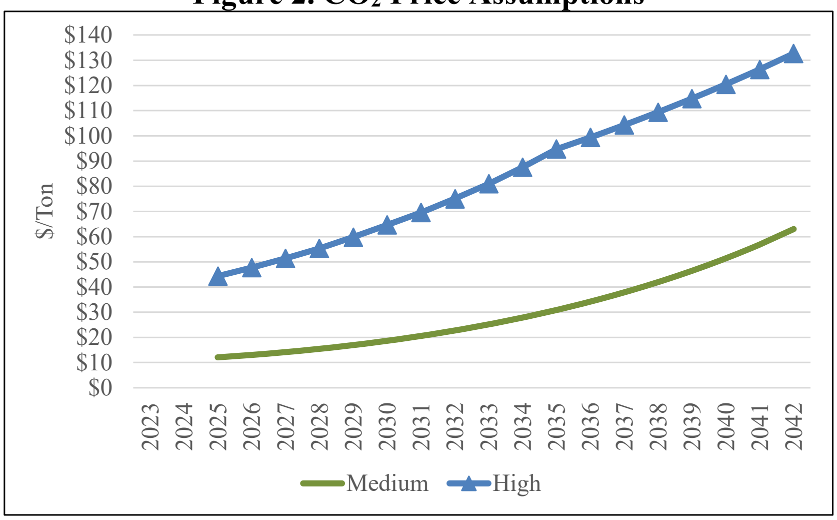


Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used three different system-wide CO_2 price scenarios—zero, medium, and high. The medium and high scenarios are derived from a survey of third-party industry experts, including IHS CERA, and Wood Mackenzie and the Energy Information Administration as well as CO_2 price assumptions used by peer utilities. The resulting

CO_2 price is applied as a tax beginning in 2025, as shown in Figure 2.[10] In addition, the Company's Chehalis natural gas-fired plant is located in Washington and is subject to Washington's cap-and-invest program established in the Climate Commitment Act, which became effective January 1, 2023. As a proxy for the auction and trading process in this program, in all CO_2 scenarios the cost of emissions from the Chehalis plant reflect the social cost of greenhouse gases used for compliance with RCW 19.280.030 and incorporates the updated inflation forecast in the Washington Utility and Transportation Commission's August 24, 2022 order in docket U-190730.

Figure 2. CO_2 Price Assumptions



Q. Does inclusion of potential future CO_2 costs reflect prudent utility planning?

A. Yes. The Company's price-policy scenarios include varying levels of assumed CO_2 costs to reflect the fact it is more likely than not that some policy will exist that will drive reduced emissions over the life of B2H and that these policies will introduce an incremental cost to fossil-fired generation. When determining CO_2 costs used for

[10] While the CO_2 price assumptions are applied as a tax, the inclusion of CO_2 prices in this way does not necessarily mean that future policies will specifically be implemented via a tax. Inclusion of a CO_2 price represents that there is a high likelihood that future policies will impute a cost on fossil-fired generation that is incremental to the cost of existing policies known today. Considering the difficulties in projecting future policy mechanisms, this incremental cost is applied for modeling purposes as a tax.

planning purposes, the Company strives to ensure that it is not an outlier. As discussed above, the medium price is within a reasonable range used by the industry to assess risk and conduct sound resource planning. The most recent example of this trend is the EPA's proposed Ozone Transport Rule restricting NOx emissions from power plants and other industrial sources.[11] This rule could impose new and significant environmental compliance obligations, resulting in upward pressure on system costs, by 2026 on PacifiCorp's coal units in Wyoming and Utah.

Q. Are the modeled CO_2 costs intended to represent a literal carbon tax?

A. No. The modeled CO_2 costs are not intended to explicitly account for a future tax on CO_2 emissions. Rather, these costs capture the effect of policies incentivizing reduced emissions through benefits or imposing costs through penalties or other costs resulting from market dynamics driving the need for reduced emissions from fossil-fired generation.

Q. Did PacifiCorp update its load forecast in its economic analysis of B2H?

A. Yes. The sales and load forecast used in preparation of this filing was completed in September 2022. It is the same load forecast that was presented at the October 13, 2022, public-input meeting for the 2023 IRP.

Q. How does this load forecast compare to the load forecast used in the 2021 IRP?

A. Figure 3 and Figure 4 show the load and peak forecast relative to the 2021 IRP forecast, both before accounting for incremental energy efficiency savings. The higher load forecast is being driven by new industrial and commercial customer growth, increased air conditioning saturations and miscellaneous devices and electric vehicle adoption

[11] *See* https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.

expectations. The updated load forecast also includes updates to weather, temperature, and line losses to account for the progression of historical data since the load forecast that informed the 2021 IRP. The updated load forecast also incorporates certain tax changes resulting from the passage of the IRA.

On average, over the 2023 through 2040 timeframe, forecasted system load is up 12.9 percent per year and forecasted coincident system peak is up 13.6 percent per year when compared to the 2021 IRP. Over that same timeframe, the average annual growth rate for the September 2022 forecast, before accounting for incremental energy efficiency improvements, is 2.0 percent for load and 1.6 percent for peak.

Figure 3. Forecasted Annual System Load

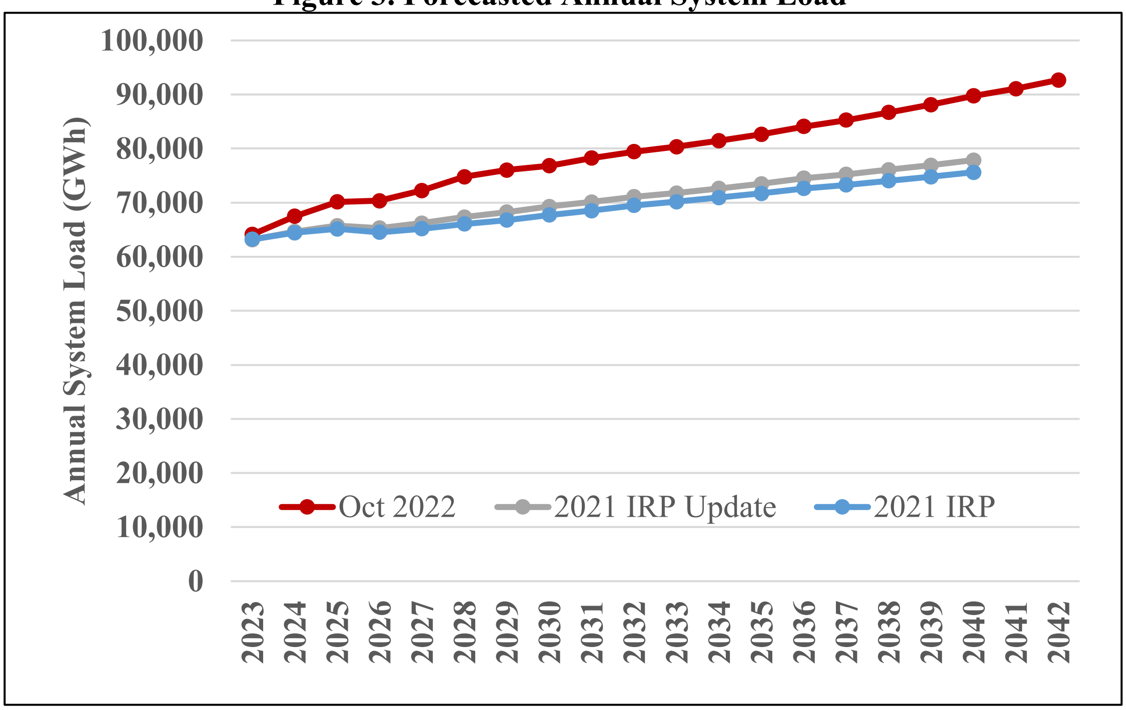
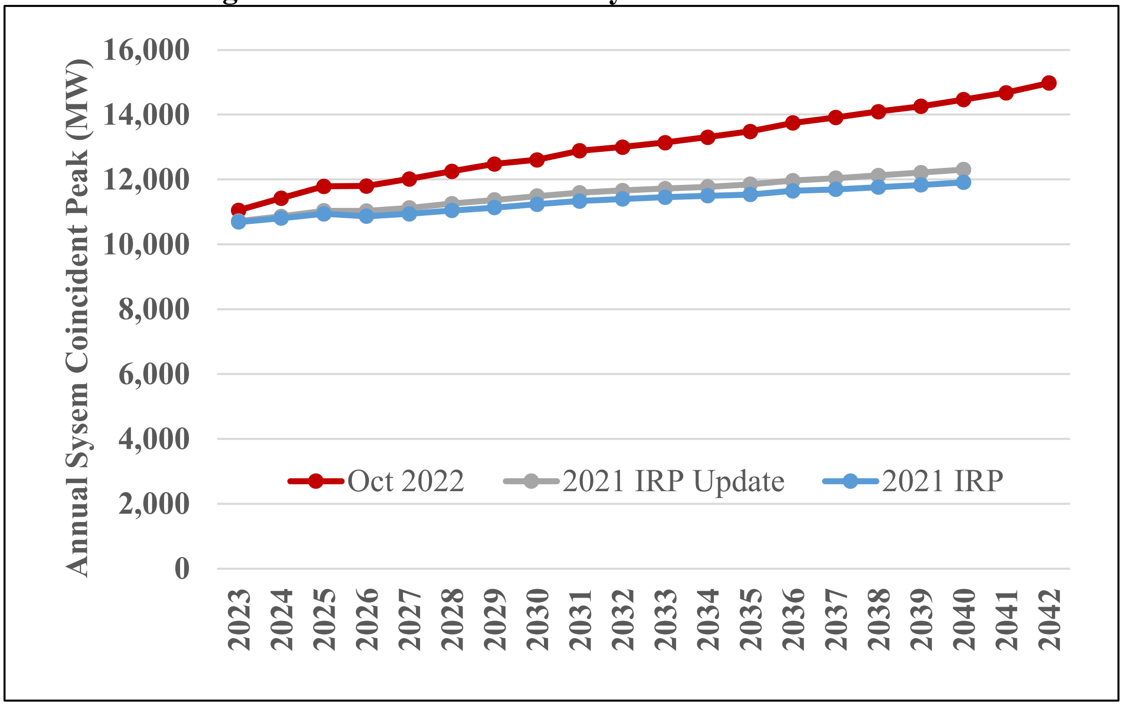


Figure 4. Forecasted Annual System Coincident Peak



Q. Has PacifiCorp incorporated EPA's proposed Ozone Transport Rule in its analysis of B2H?

A. Yes. PacifiCorp modeled two primary components to reflect the Ozone Transport Rule: NOx allowance requirements for each of its units including penalties for units with high emissions rates, and a market price for NOx allowances, based on the allowance price used in the third-party forecast to develop the September 2022 OFPC. After running the model, PacifiCorp compared the results to a forecast of its dynamic annual allocation of NOx allowances for Utah and Wyoming based on operations in earlier years.

Q. Please describe how the annual allocation of NOx allowances would work under the proposed rule.

A. EPA's very recent action on Wyoming's state implementation plan ("SIP") indicates Wyoming will not be included in the final federal ozone transport rule. EPA has extended the timeline to approve or deny Wyoming's ozone transport SIP until December 2023, and EPA cannot impose a federal implementation plan ("FIP") on Wyoming until it takes final action on the SIP. Given that background, I provide the following information with the context that it is uncertain when or if the allocation requirements will apply to Wyoming. The proposed rule calls for dynamic budgeting of NOx allowances in 2025 and beyond, with available allowances allocated among resources within a state by dividing the state NOx budget amongst eligible units based on the recent historical heat input and historical NOx emissions of each resource. Under EPA's proposed rule, the forecasted allocation of NOx allowances drops significantly in 2026, as EPA assumed that selective catalytic reduction ("SCR") installations at eligible facilities would significantly reduce emissions by that year. PacifiCorp's thermal facilities in Utah and Wyoming would be covered by the rule.

While trading of NOx allowances among participating states is allowed, the proposed Ozone Transport Rule includes significant penalties if a state's emissions exceed 121 percent of its annual allocation, including three-for-one allowance surrender for emissions in excess of 121 percent. Limited banking of NOx allowances is also allowed, but emissions met via banked allowances may also be subject to penalties if a state's emissions exceed 121 percent of the state's ozone season budget. To avoid such penalties, PacifiCorp's NOx emissions during the ozone season (May-September) in each state will not exceed 121 percent of PacifiCorp's forecasted allocation of NOx allowances for that state.

Q. Please describe how PacifiCorp developed NOx allowance requirements for each of its units.

A. In general, an allowance for one ton of NOx emissions would allow the holder of the allowance to emit one ton of NOx. However, starting in 2027,[12] the proposed Ozone Transport Rule also imposes a daily NOx emissions rate limit of 0.14 lb/MMBtu for each coal-fired facility, and requires emitters to provide an equivalent of triple allowances for any emissions that exceed that rate. For example, a resource with an emissions rate of 0.20 lb/MMBtu would have an effective allowance requirement equivalent to an emissions rate of 0.32 lb/MMBtu.[13] In order to calculate PacifiCorp's NOx allowance requirements under the Ozone Transport Rule, starting in 2027 the modeled emission rates for coal resources whose emissions exceed 0.14 lb/MMBTU were grossed up to account for the additional surrender of allowances. Note that incremental allowances do not count toward the 121 percent state emissions limit, which is based on actual emissions, and not allowance requirements.

Q. Please describe how PacifiCorp's modeling represents its NOx allowance requirements.

A. PacifiCorp's September 2022 market price forecasts incorporate a regional NOx allowance price, and this price is incorporated in several ways. First, PacifiCorp calculated its share of EPA's proposed allowance allocation for Utah and Wyoming in 2023 and 2024, and a projection of its share thereafter. To the extent emissions in a state are projected to exceed 121 percent of its estimated allocation, any incremental

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[12] Coal units that currently have SCR installed must meet the daily backstop limit in 2024. Coal units that do not currently have SCR installed must meet the daily backstop limit in 2027.

[13] Effective allowance requirement for resource with emissions rate of 0.20 lb/MMBTU: 100% * 0.20 lb/MMBtu + 200% * (0.20 – 0.14) lb/MMBtu = 100% *0.20 + 200% * 0.06 = 0.32 lb/MMBtu.

emissions are assumed to be subject to the three-for-one allowance surrender requirement, which is reflected in a cost per ton that is three times the September 2022 allowance price forecast. Because the state limits are based on emissions, the modeled emissions rates are not grossed-up starting in 2027 as described above. In addition, to the extent that overall allowances (not emissions) exceed 100 percent of PacifiCorp's projected allocation, then any incremental allowances are assumed to have a cost per ton that is equal to the September 2022 allowance price forecast. Because the PacifiCorp total requirement is based on allowances (not emissions), a distinct emissions rate is modeled which is grossed-up for emissions over 0.14 lb/MMBtu starting in 2027 as described above.

Under EPA's proposed rule, PacifiCorp will receive specified free allowances in 2023 and 2024. Starting in 2025 PacifiCorp will receive free allowances that are dynamically calculated based on heat input and emissions rates two years prior. Said another way, heat input and emissions that require an allowance today will result in a share of future allowances two calendar years later. The net present value of each unit's current year allowance requirement and its share of future year allowances is translated into an effective emissions rate for dispatch, ensuring that resources that will yield higher future benefits are dispatched ahead of those with lower future benefits, to the extent that those benefits outweigh any difference in fuel and variable costs.

Q. Please describe how PacifiCorp's NOx allowance requirements are incorporated in the reported system cost results.

A. The dynamic nature of the proposed Ozone Transport Rule complicates the modeling, because the feedback from prior year dispatch decisions is difficult to incorporate.

However, after a study is complete, it is possible to calculate allowance needs and future year allowance allocations that are specific to the dispatch and emissions results in that study. Allowance requirements (inclusive of the gross-up for emissions over 0.14 lb/MMBTU starting in 2027) are summed up, and two additional allowances are added for any emissions in excess of 121 percent of the dynamically calculated emissions requirement for each state. After subtracting off the allowance allocation, unused allowances are banked up to the specified limits, and any remaining allowances are assumed to be sold at the September 2022 forecast of the allowance price. If the allowance allocation is lower than the allowance requirement, banked allowances are used and the remaining balance is assumed to be purchased at the September 2022 forecast of the allowance price.

VII. MODELING METHODOLOGY

Q. Please describe the modeling methodology PacifiCorp used in its analysis of B2H.

A. PacifiCorp calculated a system present-value revenue requirement ("PVRR") by identifying least-cost resource portfolios and dispatching system resources through 2042, which aligns with the 20-year forecast period used in PacifiCorp's forthcoming 2023 IRP. Net customer benefits are calculated as the present-value revenue requirement differential ("PVRR(d)") between different simulations of PacifiCorp's system. One simulation includes B2H and the other simulation excludes it, and the resulting differences in PacifiCorp's modeled transmission rights between the two simulations are summarized in Table 2 below.

Table 2. Modeled Transmission Associated with B2H

Maximum Transfer Capability (MW)	**No B2H**	**With B2H**
B2H Transfers		
Existing PAC Westbound	1090	1090
IPC PTP Westbound	510	510
B2H Westbound	0	818
Total Westbound	**1600**	**2418**
IPC PTP Eastbound	100	300
B2H Eastbound	0	300
Total Eastbound	**100**	**600**
IPC Asset Transfer		
Borah to Hemingway Westbound	n/a	To PacifiCorp
Borah to Hemingway Eastbound	n/a	To PacifiCorp
To Goshen (BPA load service)	n/a	To IPC
Borah to Four Corners Southbound	n/a	To IPC
Borah to Four Corners Northbound	n/a	To IPC
Central Oregon Load Service		
Southbound to Central Oregon load	340	340
Northbound to Central Oregon load	340	340
Enabled by:	*Southern Oregon Battery & implementation of flow-based scheduling*	*B2H*
Total Central Oregon	**680**	**680**
Longhorn Area Load Service		
West to Longhorn area load	*100%**	300
East to Longhorn area load	0	818

**Longhorn load is confidential. The associated costs are identified in Confidential RMP Exhibit 3.2.*

Q. Why is PacifiCorp's share of B2H westbound capacity higher than its subscribed allocation of 600 MW?

A. The unsubscribed portion of B2H westbound capacity will be allocated between PacifiCorp and IPC based on their respective shares of the overall project. The value of 818 MW in Table 2 includes PacifiCorp's share of that unsubscribed capacity.

Q. Please describe the costs associated with the B2H transfer capability summarized above.

A. The cost of B2H, including associated equipment such as the Midline series compensation, is the largest element. While this cost will be included in PacifiCorp's rate base, it will also be recovered from third-party transmission customers of PacifiCorp Transmission, as part of its Open Access Transmission Tariff ("OATT") and annual formula rate update. As a result, approximately 80 percent of these costs are expected to be recovered from PacifiCorp's retail customers. This same percentage applies to all transmission upgrade options evaluated in PacifiCorp's IRP modeling. In the same way, because PacifiCorp uses IPC point-to-point ("PTP") transmission service to serve its retail customers, it will also pay for a portion of IPC's costs for the B2H project, through IPC's OATT rates and annual formula rate update process. This will be reflected in the rates for PacifiCorp's existing PTP reservations, and in the pending reservations that will be granted contingent upon B2H going into service. Unlike transmission capital costs for PacifiCorp-owned assets, which are partly recovered through OATT rates, the expense for third-party wheeling reservations is part of NPC and is recovered from PacifiCorp's retail customers only.

Q. Please describe the costs associated with the IPC asset transfers summarized above.

A. PacifiCorp does not have sufficient available transfer capability from its PacifiCorp East BAA at Borah to the southern terminus of B2H at Hemingway. To access the incremental transfer capability associated with B2H, PacifiCorp is negotiating an asset transfer with IPC. Many of the associated transmission assets between Borah and

Hemingway are already jointly owned by PacifiCorp and IPC, and PacifiCorp would receive a greater share both eastbound and westbound that is in line with its share of the transfer capability associated with the Project itself. In return, IPC would receive a share of transmission assets to provide bidirectional rights between Borah and Four Corners, as well as to reach BPA loads in the Goshen area. As a result of the transfer, BPA would take transmission service from IPC, rather than PacifiCorp, which would result in a loss of OATT transmission revenue for the Company. The associated change in long-term transmission reservations would flow through PacifiCorp's annual formula rate update and result in higher OATT rates. While PacifiCorp's retail customers would be a larger share of the remaining long-term reservations, it is still projected to be approximately 80 percent of the total. As a result, 80 percent of the lost revenue from BPA would be attributable to PacifiCorp retail customers, and the remainder would be collected from remaining OATT customers.

Q. Please describe the costs associated with the central Oregon load service as summarized above.

A. PacifiCorp currently has rights to serve up to 340 MW of central Oregon load via transfers on the Buckley-Summerlake 500-kV line either northbound or southbound. Because of growing loads in central Oregon, PacifiCorp is seeking to serve up to 680 MW of central Oregon load by scheduling both northbound and southbound concurrently, each at up to 340 MW. To provide this service, a series capacitor bank will be required at the Meridian substation, either with or without B2H being placed in service.

With B2H in service, no additional transmission upgrades would be required;

however, PacifiCorp would be able to consolidate certain PTP reservations on BPA's system that are used to reach central Oregon loads, resulting in a reduction in its BPA wheeling expense. Because the expense for third-party wheeling reservations is part of NPC, one hundred percent of these savings would be attributed to PacifiCorp's retail customers.

In the absence of B2H, providing this level of central Oregon load service would require at least 725 MW of dispatchable generation in southern Oregon.[14] This dispatchable generation in southern Oregon would need to be deployed when power flows from PacifiCorp to central Oregon loads across paths operated by BPA exceeded specified levels. As this is based on regional load and resource conditions, which are likely to evolve over time, there is no specific duration that can be assured of maintaining central Oregon load service at 680 MW. For this analysis, the No B2H case included an additional 725 MW of eight-hour battery storage with estimated annual fixed costs of $230 million in 2027, after accounting for the 30 percent investment tax credit available to energy storage resources in the IRA. Because the IRP analysis only includes PacifiCorp's transmission rights and forecasted usage, it cannot identify periods in which dispatchable southern Oregon generation would need to be deployed to address flows on regional transmission paths. Given this uncertainty, the battery storage duration was increased to eight hours from the four-hour assumption used for this element of the analysis in the 2021 IRP and the 2021 IRP Update. Considering these uncertainties, the 725 MW storage resource was not assumed to be

[14] A non-wires analysis performed by BPA, IPC, and PacifiCorp indicated that obtaining 680 MW of central Oregon load service capability in the absence of B2H would require dispatchable generation in Southern Oregon ranging from 725 MW to 1,450 MW to prevent impacts to other existing rated paths.

available for economic dispatch within the PLEXOS model.

Q. Please describe the costs associated with the Longhorn area load service summarized above.

A. PacifiCorp's load in the vicinity of the Longhorn substation is anticipated to grow significantly. Serving this load will require PTP transmission service with BPA, Portland General Electric ("PGE"), and/or Umatilla Electric Cooperative ("UEC"). The expense for such third-party wheeling reservations is part of NPC, so one hundred percent of these costs would be attributed to PacifiCorp's retail customers. Because of their location in proximity to B2H, these loads could instead be served via a connection to B2H. Once B2H is completed, such a connection is forecasted to be in service in May 2027, and when it is in place, third-party PTP transmission service would no longer be required. Because the transmission system costs would be recovered as part of PacifiCorp's OATT and annual formula rate update, approximately 80 percent of these costs are expected to be recovered from PacifiCorp's retail customers.

Q. Please describe how third-party transmission expenses and revenues are calculated.

A. Table 3 below summarizes the assumptions used for each of the third-party transmission providers as well as PacifiCorp's revenue from BPA, under its OATT. The rates for PGE and UEC are relatively straightforward, reflecting escalation of the current rates at inflation. The rates for BPA reflect escalation of its current PTP and Schedule 1 rates (Scheduling, System Control and Dispatch) at 3.75 percent per year (7.5 percent over each two-year rate-effective period). The cost for BPA reservations is reduced by applicable short-distance discounts. For IPC and PacifiCorp, formula rate calculations also incorporate adjustments to include the cost of B2H (for both) and Gateway South ("GWS") for PacifiCorp, as these major transmission investments appreciably increase these rates. In addition, the formula rate calculations for both IPC and PacifiCorp are also adjusted for changes in long-term contractual demand, adding PacifiCorp's additional PTP reservations to IPC's calculation and removing BPA's load from PacifiCorp's calculation.

Table 3: Third-party Transmission Service Assumptions

Provider	Service	Schedules	Escalation	Adjusted Rate Base	Adjusted Demand
BPA	PTP+SCHED	PTP+ACS	3.75%	n/a	n/a
PGE	PTP	7	2.27%	n/a	n/a
UEC	PTP	11	2.27%	n/a	n/a
IPC No B2H	PTP	7	2.27%	n/a	+100 MW
IPC w/ B2H	PTP	7	2.27%	+B2H	+100 MW
PAC No B2H	NITS	NITS	2.27%	+GWS	n/a
PAC w/ B2H	NITS	NITS	2.27%	+GWS+B2H	-314 MW

Q. What modeling tool did PacifiCorp use to evaluate the B2H project?

A. Consistent with the 2021 IRP modeling, PacifiCorp used the PLEXOS model.

Q. Please describe the PLEXOS model.

A. The PLEXOS model provides three platforms of the PLEXOS tool (referred to as long-term ("LT"), medium-term ("MT") and short-term ("ST")), which work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon. The PLEXOS tool also allows for endogenous modeling of resource options simultaneously, greatly reducing the volume of individual portfolios needed to evaluate impacts of varying resource decisions.

Q. Please describe how PacifiCorp used the LT model.

A. PacifiCorp used the LT model to produce a unique resource portfolio under MM price-policy conditions. The LT model portfolio is informed by an hourly review of reliability based on ST model simulations (described below). This ensures that each portfolio meets minimum reliability criteria in all hours. While the 2021 IRP and 2021 IRP Update both assumed that B2H would enable 600 MW of generator interconnection capability, recent generator interconnection study results do not indicate that the B2H project is directly required for pending interconnection requests. Therefore, PacifiCorp did not assume any generating resources would be enabled by B2H and did not make any resource changes between cases that included B2H and cases without it. While there are currently no pending interconnection requests that require B2H, future interconnection requests in the vicinity of B2H could still be contingent upon its completion.

Q. Please describe how PacifiCorp used the MT model.

A. PacifiCorp used the MT model to perform stochastic risk analysis of the portfolios. Each portfolio was evaluated for cost and risk for each price-policy scenario. A primary function of the MT model is to calculate an optimized risk-adjustment, representing the relative risk of a portfolio under unfavorable stochastic conditions for that portfolio.

Q. Please describe how PacifiCorp used the ST model.

A. PacifiCorp used the ST model to evaluate each portfolio to establish system costs over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a PVRR, which serves as the basis for selecting least-cost, least-risk portfolios. As noted above, ST model simulations were also used to identify the potential need for resources in the portfolio to maintain system reliability.

Q. How did each of the three PLEXOS models work together to inform the economic analysis presented here?

A. In the first step, a resource portfolio without B2H was developed using the LT model. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves, and regulation reserves plus a minimum capacity reserve margin for each load area represented in the model.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new demand-side management ("DSM") alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. Dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present-value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

Each portfolio developed by the LT model must have sufficient capacity to be reliable over the IRP's 20-year planning horizon. The resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental DSM resources.

Q. What is the next step in the modeling process?

A. In the second step, the Company conducted a reliability assessment using the ST model. The ST model begins with a portfolio of resources and transmission from the LT model that has not yet benefited from a reliability assessment conducted at an hourly level. The ST model is first run at an hourly level for 20 years in order to retrieve two critical pieces of data: 1) shortfalls by hour; and 2) the value of every potential resource to the system. This information is then used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. The ST model is then run again with the modified portfolio to calculate an initial PVRR, which is risk-adjusted by outcomes of MT model stochastics that occurs in the third step of the process.

Q. Please describe how the MT model is used to conduct cost and risk analysis.

A. In the third step, the resource portfolios developed by the LT model and adjusted for reliability by the ST model are simulated in the MT model to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. The MT results are used to calculate a risk adjustment which is combined with ST model system costs to achieve a final risk-adjusted PVRR.

Q. Is the PLEXOS model appropriate for analyzing the customer benefits of B2H?

A. Yes. The PLEXOS model is the appropriate modeling tool when evaluating significant capital investments that influence PacifiCorp's portfolio and affect least-cost dispatch of system resources. The LT model is needed to understand how the type, timing, and location of future resources might be coordinated to cost-effectively serve customer load. The ST and MT models provide additional granularity on how B2H is projected to affect system operations, including its impact on stochastic risks. Together, the LT, MT, and ST models are well suited to perform a benefit analysis for B2H that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP and resource procurement activities.

Q. When developing resource portfolios with the PLEXOS model, did you perform a reliability assessment?

A. Yes. As described above, the ST model was used to establish system costs for the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes that will reveal whether an initially reliable portfolio selected by the LT model leaves shortfalls at an hourly level, which can then be addressed.

Q. Did PacifiCorp analyze how other assumptions affect its economic analysis of the B2H project?

A. Yes. PacifiCorp analyzed the B2H project under four price-policy scenarios.

VII. PRICE-POLICY SCENARIO RESULTS

Q. Please summarize the PVRR(d) results calculated from the PLEXOS model.

A. Table 4 summarizes the risk-adjusted PVRR(d) results for each price-policy scenario. The data that was used to calculate the PVRR(d) results shown in the table are provided in Confidential RMP Exhibit 3.2.

Table 4. PVRR(d) Cost/(Benefit) of B2H ($ million), 2023-2042

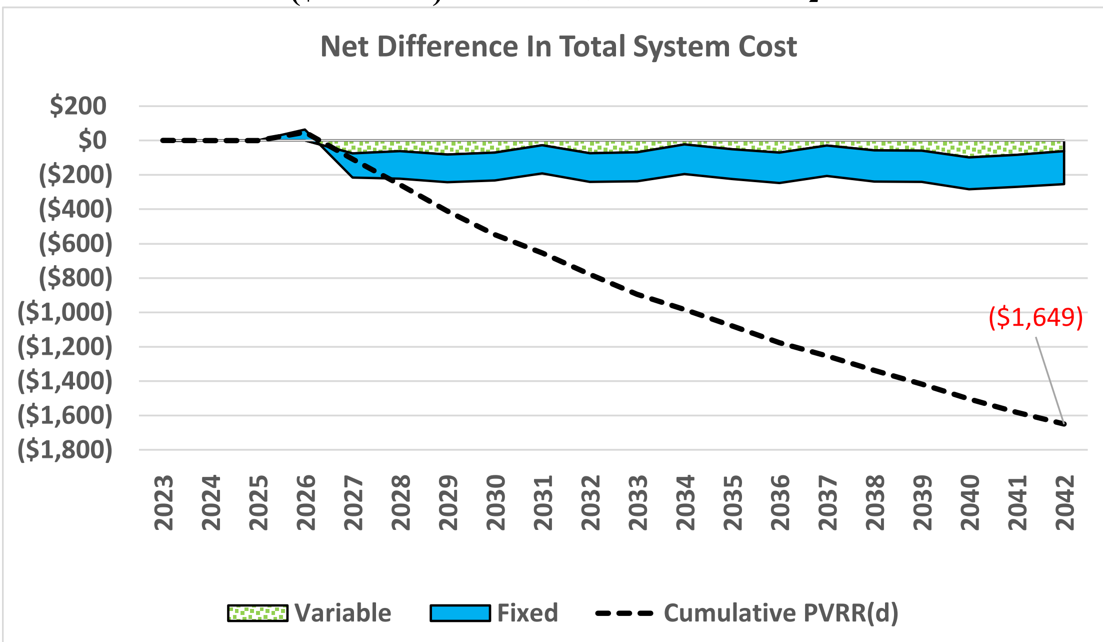
Price-Policy Scenario	B2H	Asset and Reservation Exchange	System Dispatch Impacts	Central Oregon Load Service	Longhorn Area Load Service	Total
MM	$454	$308	($520)	($1,811)	($143)	($1,713)
MN	$454	$308	($594)	($1,811)	($143)	($1,786)
LN	$454	$308	($488)	($1,811)	($143)	($1,680)
HH	$454	$308	($295)	($1,811)	($143)	($1,487)

As shown above, system costs are lower when B2H is included in the portfolio in all price-policy scenarios. The majority of the benefits are derived from the fixed cost of providing central Oregon load service, which are substantially lower as a result of B2H being placed into service. Both central Oregon load service and Longhorn area load service are solely comprised of fixed costs that are not impacted by system dispatch or the price-policy scenario assumptions.

Q. How do system costs change with and without B2H over time?

A. Figure 5 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when B2H is eliminated from the portfolio. The graph shows annual net changes in fixed and variable costs and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio that includes B2H is $1,649 million lower cost than the portfolio without B2H, before accounting for risk.

Figure 5. Increase/(Decrease) in System Costs when B2H is Included in the Portfolio ($ millions) Medium Gas/Medium CO_2



IX. ANNUAL REVENUE REQUIREMENT

Q. In addition to the modeling used to calculate present-value net benefits over a 20-year planning period, has PacifiCorp forecasted the change in nominal revenue requirement due to B2H?

A. Yes. The system PVRR from the PLEXOS model was calculated from an annual stream of forecasted revenue requirement over the period 2023 through 2042. The annual stream of forecasted revenue requirement captures nominal revenue requirement for non-capital items (*i.e.*, NPC, fixed operations and maintenance, PTCs, etc.) and levelized revenue requirement for capital expenditures. To estimate the annual revenue-requirement impacts of B2H, capital costs need to be considered in nominal terms (*i.e.*, not levelized).

Q. Why is the capital revenue requirement used in the calculation of the system PVRR from the PLEXOS model levelized?

A. Levelization of capital revenue requirement is necessary in these models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. Without levelization, this potential distortion is driven by how capital costs are included in rate base over time. Capital revenue requirement is generally highest in the first year an asset is placed in service and declines over time as the asset depreciates. In the context of long-term resource planning that is conducted over a finite planning horizon, this can inappropriately favor less capital-intensive assets or assets with longer lives even if those assets might increase system costs over their remaining life.

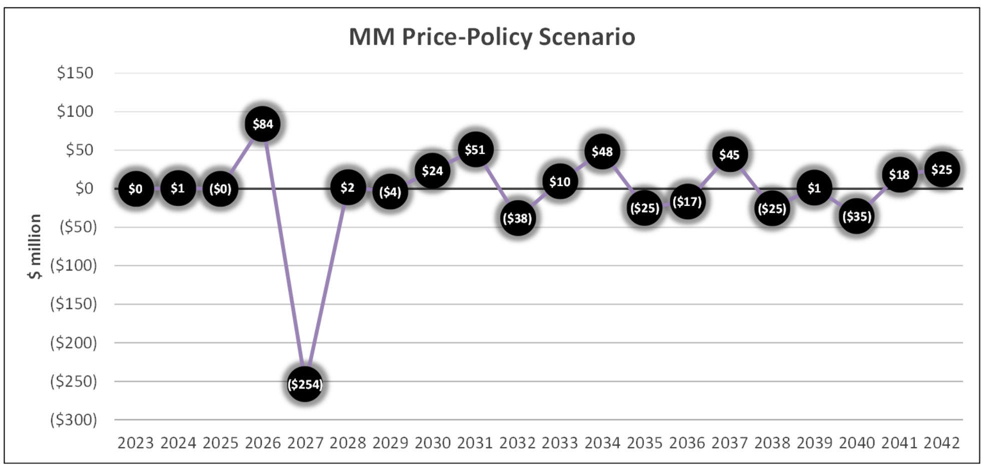
Q. How did PacifiCorp forecast the annual revenue-requirement impacts of B2H?

A. For each simulation, the annual stream of levelized revenue requirement associated with the initial capital for each resource and transmission addition, including B2H, is recalculated as a nominal revenue requirement through 2042, which aligns with the modeled study horizon. Since this change only applies to the cost stream associated with initial capital, all other costs that are part of the annual revenue requirement (e.g. fuel, market transactions, emissions), are unchanged from the modeled results.

Q. Please describe the change in annual nominal revenue requirement from B2H.

A. Figure 6 shows the estimated change in annual nominal-revenue requirement due to B2H for the MM price-policy scenario on a total-system basis. The annual revenue requirement shown in the figure reflects all costs for B2H, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), operations and maintenance expenses, net of avoided transmission costs, changes to wheeling expenses and revenues, and transmission revenue credits. The project costs are netted against system impacts of B2H, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are enabled by, but not directly associated with, the incremental transfer capability from B2H.

Figure 6. Total-System Change in Annual Revenue Requirement Due to B2H ($ million)



In 2027, the first full year that B2H is in service, the total-system nominal revenue requirement decreases by $254 million. Thereafter, while the net change in revenue requirement from year to year shows modest variation, B2H continues to enable a lower overall revenue requirement through the end of the study horizon.

X. AGREEMENTS RELATED TO B2H

Q. Please summarize the agreements among the parties regarding funding and construction of B2H.

A. The initial B2H agreement among IPC, BPA, and the Company was a Joint Permit Funding Agreement, executed January 12, 2012, and amended several times, to jointly support the regulatory processes associated with obtaining necessary permits and other project development work. On January 18, 2022, the parties executed a non-binding term sheet as the framework for future agreements, which is included as RMP Exhibit 3.1 to my testimony.

Prior to execution of the term sheet, BPA decided to transition out of its role as a joint permit funding coparticipant and to instead rely on B2H by taking transmission service from IPC to serve its customers, leaving only the Company and IPC as owners of B2H. As a result of BPA's decision to take transmission service from IPC, the term sheet stipulates that IPC will acquire BPA's B2H project capacity, which increased IPC's B2H project ownership share to 45.45 percent.[15] Because IPC assumed the entirety of BPA's ownership interest in B2H, BPA's transition did not affect the Company's ownership interest. When B2H is completed, IPC and the Company will jointly own as tenants in common the transmission line and all associated facilities and equipment.[16] IPC will fund and own 45.45 percent of B2H and the Company will fund and own 54.55 percent of B2H. Per the term sheet, IPC is the project manager primarily responsible for federal, state, and local permitting efforts and construction of the

[15] Exhibit 3.1, term sheet at 24 [hereinafter "Term Sheet"].
[16] Term Sheet at 26.

Project, except that BPA will be responsible for designing, procuring, and constructing the Longhorn substation and relocating and replacing an existing BPA 69-kV line.[17]

Q. Do agreements relating to B2H remain outstanding?

A. Yes. As relevant to my testimony, there are several agreements between PacifiCorp's merchant function and IPC and BPA. First, the following transmission service requests will be executed or changes to existing transmission services agreements will be made:

- IPC will acquire from BPA 500 MW of PTP transmission service from Mid-C to Longhorn, and
- PacifiCorp will renew its 510 MW of PTP transmission service from IPC, as shown in the line item Idaho Power PTP Westbound in Table 2.

Second, BPA will redirect and then assign to PacifiCorp 200 MW of PTP transmission rights it holds on IPC's system. In particular, upon B2H energization, BPA has agreed to submit redirect requests to IPC for BPA's two existing 100 MW conditional firm PTP service agreements on IPC's system, with each having a new point of receipt of Walla Walla and a new point of delivery of Borah. Once the redirects have been approved and granted by IPC, BPA will assign the redirected service agreements to PacifiCorp. This is reflected in Table 2 in the 200 MW increase in the line item IPC PTP eastbound.

Third, PacifiCorp and BPA will amend the Midpoint-Meridian Agreement to remove PacifiCorp's legacy scheduling rights over Buckley-Summerlake 500-kV line (North-to-South or South-to-North for up to 340 MW), thereby facilitating the revisions

[17] Term Sheet at 25.

to the PTP service discussed below. This is reflected in Table 2 in the central Oregon load service section.

Fourth, PacifiCorp will update multiple PTP service agreements with BPA to reflect expansion of its central Oregon load service. The revisions will accommodate, upon B2H energization, 680 MW of firm PTP transmission rights into PacifiCorp's 230-kV system at points of delivery at Ponderosa 230-kV and Pilot Butte 230-kV. This is reflected in Table 2 in the central Oregon load service section.

XI. ADVANCED REVIEW PROCESS INFORMATION REQUIREMENTS

Q. Are you familiar with the Advanced Review Process for certain transmission assets in Wyoming?

A. Yes.

Q. What does the Advanced Review Process require?

A. Under the Advanced Review Process, the Company agreed to ask the Commission to "rule on whether the proposed construction of the transmission line is reasonable and in the public interest in advance of the line being constructed."[18] The Company also agreed to provide certain additional information in support of a CPCN application, including a "detailed analysis and quantification of the benefits of the facilities to both the overall PacifiCorp system and to Wyoming customers in particular in terms of increased reliability or relatively lower net power costs, increased generation alternatives and the benefits of generation diversity."[19]

[18] *In The Matter Of The Application Of Rocky Mountain Power For Approval Of A General Rate Increase In Its Retail Electric Utility Service Rates In Wyoming Of $ 97.9 Million Per Annum Or An Average Overall Increase Of 17.3 Percent,* Docket No. 20000-384-ER-10, Record No. 12702 (Sept. 2011) ["2010 Stipulation"] at ¶13(a)(ii).
[19] *Id.* at ¶13(a)(iii)(3).

Q. Is there specific information that the Company must provide for purposes of the Advanced Review Process?

A. Yes. I discuss two of those information requirements in my testimony: a detailed analysis of the benefits of the Project and a discussion of the alternatives to the proposed facility.

Q. What are the benefits of the Project for Wyoming customers?

A. As I discussed above, the Project results in substantial net benefits in all price-policy scenarios, including net benefits of approximately $1.713 billion in a scenario assuming medium prices for natural gas and CO_2. These benefits accrue directly to Wyoming customers because the costs that are avoided by virtue of B2H would have been costs allocated to Wyoming customers in accordance with the Company's inter-state cost allocation protocol.

Q. What are the alternatives to B2H?

A. As I discussed above, serving the growing customer load in central Oregon without B2H would require at least 725 MW of dispatchable generation in southern Oregon.[20] For my analysis, the No-B2H case included an additional 725 MW of eight-hour battery storage with estimated annual fixed costs of $230 million in 2027, after accounting for the 30 percent investment tax credit available to energy storage resources in the IRA. Serving the growing load near the Longhorn substation in the absence of B2H would require PTP contracts with third-party transmission providers in the region. These alternatives are more costly than construction of B2H.

[20] A non-wires analysis performed by BPA, IPC, and PacifiCorp indicated that obtaining 680 MW of central Oregon load service capability in the absence of B2H would require dispatchable generation in Southern Oregon ranging from 725 MW to 1,450 MW to prevent impacts to other existing rated paths.

XI. CONCLUSION

Q. Please summarize the conclusions of your direct testimony.

A. PacifiCorp's analysis shows that B2H is necessary, reasonable, and in the public interest, supporting the requested waivers or issuance of a non-situs CPCN and approval under the Advanced Review Process.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A WAIVER OF THE NON-SITUS CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR GATEWAY SEGMENT H, THE BOARDMAN TO HEMINGWAY TRANSMISSION PROJECT	)	DOCKET NO. 20000-___-EN-23 (RECORD NO. _______)

AFFIDAVIT, OATH AND VERIFICATION

Rick T. Link (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is the Senior Vice President, Resource Planning, Procurement, and Optimization for PacifiCorp, which is a party in this matter.

Affiant prepared and caused to be filed direct testimony in this proceeding. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant's knowledge, all statements and information contained within the testimony and all of its associated attachments are true and complete and constitute the recommendations of the Affiant in his official capacity as Senior Vice President, Resource Planning, Procurement, and Optimization.

Further Affiant Sayeth Not.

Dated this 2nd day of February, 2023

Rick T. Link
825 NE Multnomah
Portland, OR 97232

STATE OF Oregon)
) SS:
COUNTY OF Multnomah)

The foregoing was acknowledged before me by Rick T. Link on this 2nd day of February, 2023. Witness my hand and official seal.

Tyrone M Hildreth
Notary Public

My Commission Expires: 4-11-2025

OFFICIAL STAMP
TYRONE MACGREGOR HILDRETH
NOTARY PUBLIC - OREGON
COMMISSION NO. 1011109
MY COMMISSION EXPIRES APRIL 11, 2025

Rocky Mountain Power
Exhibit 3.1
Docket No. 20000-___-EN-23
Witness: Rick T. Link

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rick T. Link

B2H Term Sheet Dated January 18, 2022

February 2023

Contract No. 22TX-17207

TERM SHEET

THIS TERM SHEET IS INTENDED SOLELY TO FACILITATE DISCUSSIONS AMONG IDAHO POWER COMPANY ("***IDAHO POWER***" or "***IPC***"), PACIFICORP ("***PACIFICORP***" or "***PAC***"), AND THE BONNEVILLE POWER ADMINISTRATION ("***BPA***") (EACH REFERRED TO HEREIN AS A "***PARTY***" AND COLLECTIVELY REFERRED TO HEREIN AS THE "***PARTIES***") RELATED TO THE CONSTRUCTION, OWNERSHIP, OPERATION, ASSET EXCHANGES, AND SERVICE AGREEMENTS REGARDING THE BOARDMAN TO HEMINGWAY TRANSMISSION LINE PROJECT ("***B2H PROJECT***" OR "***PROJECT***") AND OTHER TRANSMISSION FACILITIES. EXCEPT FOR SECTION 5 OF THIS TERM SHEET WHICH SHALL BE LEGALLY BINDING UPON THE PARTIES UPON THE EXECUTION AND DELIVERY OF THIS TERM SHEET BY ALL OF THE PARTIES (THE "***EFFECTIVE DATE***"), (I) THIS TERM SHEET IS NOT INTENDED TO CREATE, NOR SHALL IT BE DEEMED TO CREATE, A LEGALLY BINDING OR ENFORCEABLE AGREEMENT OR OFFER, AND (II) NO PARTY SHALL HAVE ANY LEGAL OBLIGATION WHATSOEVER PURSUANT TO THIS TERM SHEET.

1. **BPA Requirements.** The Parties acknowledge and agree that in order to negotiate the Agreements (as defined below) and before BPA can make a definitive final decision regarding whether to enter into the Agreements, BPA must (1) engage in customer and stakeholder outreach, share information about this Term Sheet during the outreach, and solicit feedback; (2) fulfill all requirements under the National Environmental Policy Act (NEPA), the National Historic Preservation Act (NHPA) and other applicable environmental laws, and (3) make a definitive decision in an Administrator's final record of decision. Nothing in this Term Sheet shall be construed as indicating that BPA has engaged in customer and stakeholder outreach; completed its NEPA and other environmental review processes or made a decision regarding how to proceed.

2. **Term.** This Term Sheet shall terminate the earlier of (a) energization of the B2H Project, or (b) execution of all agreements identified in the Term Sheet, or (c) mutual written agreement of all Parties. This Term Sheet may be extended by mutual written agreement of all Parties.

3. **Agreements.** Upon execution of this Term Sheet, the Parties intend to negotiate in good faith toward the execution of the definitive, binding agreements and amendments between or among the Parties described below consistent with the terms and conditions described below ("***Agreements***"). Each of the Parties intends to prepare and deliver to the other Parties initial drafts of the Agreements it is designated as responsible for below by no later than the date identified for each agreement. The Parties further intend, subject

to the BPA requirements in Section 1, that they will endeavor to complete negotiation of and execute the Agreements by no later than the date identified for each agreement; provided, however, that the effectiveness of any such Agreement may be subject to one or more conditions precedent, including state or federal regulatory approvals.

a) Asset Exchanges, Transmission Service Agreements, and Amended and Restated Existing and Future Agreements: The table below defines the transactions contingent on completion of the B2H Project including, without limitation, regulatory approval associated with IPC's acquisition of BPA's interest in the Amended and Restated Boardman to Hemingway Transmission Project Joint Permit Funding Agreement ("Joint Permitting Agreement"), asset exchanges, transmission service agreements, and amended and restated existing and future agreements. Each of the Parties will prepare an initial draft of the Agreements and Amendments below for which it is designated as the Primary Drafter, consistent with the following terms:

	Parties / Agreement / Action / Primary Drafter	***General Terms / Details***
1.	***PAC, BPA*** ***Agreement on Principles and Timelines*** ***Prepare First Draft – BPA: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	PAC and BPA are parties to the Amended and Restated Midpoint-Meridian Agreement, originally executed June 1, 1994 (the "Midpoint-Meridian Agreement"), which provides PAC with 340 MW of bidirectional scheduling rights over the Buckley-Summer Lake 500kV line (the "Buckley-Summer Lake Line"). In connection with the Goshen Area Asset Exchange (as referenced in Section 3(a)(7) of this table) and the B2H Midline Series Capacitor Project (as referenced in Section 3(a)(12) of this table), PAC and BPA are discussing options to allow PAC the ability to schedule 340 MW from the Buckley substation to the 500kV side of the Ponderosa Transformer Bank 500/230 kV #1 ("Ponderosa 500") and to concurrently schedule 340 MW from the Summer Lake substation to Ponderosa 500 upon energization of the B2H line and the B2H Midline Series Capacitor Project. I. Contingent upon the conditions set forth below, PAC and BPA desire for the concurrent bidirectional scheduling rights over the Buckley-Summer Lake line to be provided as firm point-to-point transmission service ("PTP service") pursuant to the terms and conditions in BPA's Tariff and rate schedules upon energization of the B2H line

		and the B2H Midline Series Capacitor Project. As of the Effective Date, the PAC and BPA understand that such PTP service remains subject to further BPA evaluation. a. BPA's offer of PTP service may include conditions if such conditions are identified during BPA's evaluation. Conditions for PTP service are at BPA's sole discretion and, if required, will be developed consistent with the principles set forth in Section 3(a)(1)(II)(b) so that flows associated with the PTP service over the Buckley-Summer Lake line do not exceed 340 MW in the north-to-south direction and concurrently does not exceed 340 MW in the south-to-north direction during all lines in service. b. As part of the PTP service evaluation, PAC and BPA will also explore options to combine an offer of PTP service with the modification to points of receipt and points of delivery in PAC's existing PTP service tables ("redirect") within the Long Term Firm Point-to-Point Service Agreement (No. 04TX-11722) between PAC and BPA, subject to BPA's Tariff and related business practices including available transfer capability ("ATC"), with a goal to optimize PAC's transmission service over the Federal transmission system to serve its central Oregon loads (*e.g.*, using a single wheel from a network point of receipt to PAC's load at Ponderosa 230 or Pilot Butte 230). BPA will apply its long-standing practice to evaluate the ATC impacts of the new PTP service against the ATC impacts of existing service, to include the bidirectional scheduling rights and redirected service. c. BPA may request additional information from PAC. PAC will make good faith efforts to provide such information within 30 days of BPA's request. d. PAC will submit applicable transmission service request(s) ("TSR") within 30 days

		of BPA’s notice to PAC that such requests should be submitted. e. If BPA determines, in its sole discretion, that BPA can convert the bidirectional scheduling rights to PTP service, BPA agrees to offer PTP service pursuant to BPA’s Tariff and rate schedules. i. The PTP service will be contingent upon and will not be effective before (A) the energization of the B2H line and the installation of the B2H Midline Series Capacitor Project; (B) approval by the Federal Energy Regulatory Commission (“FERC”) of the proposed amendments to the Midpoint-Meridian Agreement discussed in this Section 3(a)(1), per subpart (iii below; and (C) the Goshen Area Asset Exchange set forth in Section 3(a)(7) of this table is completed and all associated agreements are in effect. ii. PAC and BPA will adhere to the applicable requirements set forth in BPA’s Tariff and related business practices, including timelines for execution or amendment of a service agreement. iii. Concurrent with the execution of the PTP service agreements contemplated in this Section 3(a)(1)(I), PAC and BPA will amend Section 4(a) of the Midpoint-Meridian Agreement to remove and otherwise terminate PAC’s bidirectional scheduling rights over the Buckley-Summer Lake Line. f. If BPA offers PTP service that satisfies PAC’s objectives as expressed in this Term Sheet, PAC intends to accept such service subject to the condition regarding FERC approval described below. If following FERC acceptance without material conditions of the arrangements negotiated between BPA and PAC in this Section 3(a)(1)(I), PAC nonetheless fails to submit applicable TSRs or otherwise

		declines to accept the PTP service or execute a PTP service agreement, then BPA will have no further obligations to provide PAC with the PTP service described in this Section 3(a)(1)(I) or the scheduling rights described in Section 3(a)(1)(II) below. g. PAC and BPA will negotiate in good faith to complete and enter into agreements needed to complete the other conditions set forth in Sections 3(a)(2) through (14) and 3(c) of this Term Sheet, as such conditions are applicable to either Party. h. PAC will seek FERC guidance as necessary and file the proposed amendment to the Midpoint-Meridian Agreement with FERC for acceptance. BPA will reasonably coordinate with PAC to prepare for FERC meetings and submissions. FERC's unconditioned acceptance shall be a condition to PAC's obligations as contemplated under this Term Sheet. II. Following either (1) BPA's determination that it is unable to provide the PTP service to PAC consistent with Section 3(a)(1)(I) above, or (2) FERC's failure to accept without material conditions the arrangements negotiated between PAC and BPA under Section 3(a)(1)(I) above, BPA will, effective upon energization of the B2H line and the B2H Midline Series Capacitor Project provided that all conditions described below are met, provide PAC with bidirectional scheduling rights over the Buckley-Summer Lake line which give PAC the ability to (A) schedule 340 MW from the Buckley substation to Ponderosa 500 ("North to South schedules") and (B) concurrently schedule 340 MW from the Summer Lake substation to Ponderosa 500 ("South to North schedules") (collectively referred to as "scheduling limits"). The concurrent, bidirectional scheduling rights described in the immediately preceding sentence will be

		provided pursuant to an amendment to the Midpoint-Meridian Agreement and one or more separately negotiated agreements, that will be effective upon acceptance by FERC and after all conditions set forth in this Section 3(a)(1)(II) are met and will remain in effect until BPA offers PTP service as set forth in Section 3(a)(1)(I). PAC and BPA will work in good faith to satisfy all such conditions consistent with the principles articulated in Section 3(a)(1)(II)(b) below by energization of the B2H line. a. <u>Transmission service to move from the Ponderosa 500 substation</u>. The utilization of the concurrent bidirectional scheduling rights at the Ponderosa substation described in this Section 3(a)(1)(II) is limited to Ponderosa 500. PAC must reserve PTP service from BPA pursuant to BPA's Open Access Transmission Tariff ("OATT"), business practices, and rate schedules in effect at the time of such reservation to move from Ponderosa 500 to the 230 kV side of Ponderosa transformer bank #1 for delivery to PAC load in central Oregon. b. <u>Principles to guide satisfaction of conditions</u>. i. North to South schedules, South to North schedules, and the associated directional power flows may not exceed the scheduling limits (*e.g.*, 340 MW North to South and, concurrently, 340 MW South to North, under all lines in service). A Power Transfer Distribution Factor ("PTDF") based methodology ("PTDF algorithm") and calculator will be used to determine directional power flow. The PTDF algorithm will sum positive flows in the North to South and South to North directions (*i.e.*, schedules and flows are not netted). ii. If, at any time, North to South schedules, South to North schedules, or the associated directional power

		flows exceed the scheduling limits, PAC shall reduce the schedules so that the schedules and directional power flows are within the scheduling limits. BPA can, at BPA's sole discretion, curtail the schedules in whole or in part to maintain the scheduling limits and to mitigate congestion, such as during outages. iii. Schedules (E-Tags) must contain a single granular source and sink. Sources and sinks (1) cannot be consolidated on a single E-Tag; and (2) must be granular enough to determine the PTDF impact. Sources and sinks that are scheduling points, hubs, or nodes are not sufficiently granular to determine the PTDF impact. iv. PAC may not schedule from sources and sinks for which the PTDF impact has not been determined. PAC will provide BPA with advance notice of sources and sinks with sufficient time for BPA to determine the PTDF impact and, if necessary, to accommodate modifications to tools, systems, and contracts. v. The terms, tools, and protocols associated with the concurrent bidirectional scheduling rights will be structured to minimize to the maximum extent possible any impacts exceeding the scheduling limits (*e.g.*, 340 MW North to South and, concurrently, 340 MW South to North, under all lines in service) that the physical flows associated with the concurrent bidirectional scheduling rights have on the Pacific Northwest AC Intertie (as such transmission facilities are defined in the various PNW AC Intertie-related agreements among PAC, BPA and the other PNW AC Intertie owners, the "NW AC Intertie") or the Federal transmission

		system, as reasonably determined by BPA. c. <u>Conditions to Effectiveness of 3(a)(1)(II) Scheduling Rights</u> i. <u>PTDF calculator</u>. BPA will develop a PTDF algorithm to calculate the directional power flow associated with each source and sink that PAC intends to schedule. PAC and BPA will coordinate to develop, at PAC's expense, a PTDF calculator that uses the PTDF algorithm and related communication equipment. ii. <u>Agreement on operational terms</u>. After the PTDF calculator is developed, PAC and BPA will work in good faith to develop operational terms, to include the protocols and requirements for monitoring, dispatch, curtailment, reduction of scheduling limits due to outages, and future modifications to stay current with reliability standards, automation, and technological abilities. The operational terms will remain in effect for the duration of the concurrent bidirectional scheduling rights described in this Section 3(a)(1)(II) and will be incorporated into the proposed amendments to the Midpoint-Meridian Agreement or such other agreement as mutually agreed by PAC and BPA. iii. Energization of the B2H Project, including the B2H Midline Series Capacitor Project. iv. The agreements set forth in Section 3(a)(1)(III) below are, to the extent required, accepted for filing at FERC without material conditions. v. The Goshen Area Asset Exchange set forth in Section 3(a)(7) of this table is completed and all associated agreements are in effect. III. Agreements.

		a. <u>Agreement on Principles and Timelines</u>. Following execution of the Term Sheet, PAC and BPA will negotiate and execute an agreement to reflect the objectives, commitments, principles, conditions, and timelines, including negotiation of applicable follow-on agreements for the PTP service described in Section 3(a)(1)(I), and the concurrent, bidirectional scheduling rights described in Section 3(a)(1)(II). With regard to the concurrent, bidirectional scheduling rights described in Section 3(a)(1)(II), the Agreement on Principles and Timelines would include the principles and conditions set forth in Section 3(a)(1)(II) above, and the timelines for development of the PTDF calculator and negotiation of operational terms and protocols. b. <u>Follow-on Agreements</u>. Before energization of B2H and subject to the conditions described above in this Section 3(a)(1) being met, PAC and BPA will negotiate and execute (1) the agreements and amendments referenced in Section 3(a)(1)(I) above, or (2) if BPA is not yet providing PTP service upon B2H energization consistent with Section 3(a)(1)(I) above, then an amendment to the Midpoint-Meridian Agreement to reflect the addition of the concurrent bidirectional scheduling rights, including term, scheduling and directional power flow requirements, usage of the PTDF calculator, and operational terms, all as consistent with Section 3(a)(1)(II) above. PAC and BPA understand that PAC may be required to file amendments to the Midpoint-Meridian Agreement with FERC for acceptance and that the effective date for the agreements referenced above will be upon FERC acceptance without material conditions. IV. Consistent with the "Phase II Joint Study Report (2020-2021), Boardman to

		Hemingway (B2H) and Incremental Central Oregon Load" completed on March 23, 2021, upon notice from BPA, PAC will upgrade the existing Meridian Series Capacitor on the 500 kilovolt bus or install an electrically equivalent series capacitor on the PAC section of the Dixonville-Meridian-Klamath Falls-Captain Jack lines in southern Oregon within a reasonable time after receiving the notice. PAC shall be responsible for all costs associated with the upgrade. V. PAC and BPA agree that the proposed modifications to the Midpoint-Meridian Agreement described above are limited in scope to PAC's bidirectional scheduling rights over the Buckley-Summer Lake line under Section 4 of the Midpoint-Meridian Agreement and do not include BPA's bidirectional scheduling rights over the Summer-Lake Malin line under Section 4 of the Midpoint-Meridian Agreement. PAC and BPA do not intend to modify, change, alter, or terminate BPA's bidirectional scheduling rights over the Summer Lake-Malin line set forth in Section 4 of the Midpoint-Meridian Agreement or the General Transfer Agreement between PAC and BPA, originally executed May 4, 1982, as amended.
2.	***IPC & PAC & BPA*** ***New operational agreement between IPC, PAC & BPA*** ***Prepare First Draft – BPA: Quarter 3 of Calendar Year 2022*** ***Target Execution Date: Quarter 4 of Calendar Year 2022***	IPC, PAC and BPA agree to negotiate in good faith and draft a tri-party operational agreement that will: a. Consider Midpoint-Meridian Agreement Section 5(f); and b. Define the curtailment procedures between NW AC Intertie, Western Electricity Coordinating Council (WECC) Path 14 (Idaho to Northwest), and WECC Path 75 (Hemingway – Summer Lake); and c. Identify conditions for revising the tri-party operational agreement including, but not limited to: i. Engagement with NW AC Intertie partners;

		ii. In the event the B2H Project and the B2H Midline Series Capacitor Project are not complete and energized by 2027. The Parties will make best efforts to negotiate and target execution of the tri-party operational agreement within one year of the Effective Date of this Term Sheet, with an effective date for the tri-party operational agreement a reasonable time thereafter.
3.	***PAC & BPA*** ***Termination of Existing NITSAs:*** ***PAC Trans – BPA Merchant NITSAs (SA Nos. 746, 747)*** ***Incorporate into Agreement on Principles and Timelines under 3(a)(1)***	BPA Network Integration Transmission Service Agreements ("NITSAs") (PacifiCorp Service Agreement No. 746 and No. 747): BPA and PAC agree to terminate the aforementioned NITSAs upon (1) the completion of the asset purchase and sale between IPC and PAC as detailed in Section 3(a)(5) through Section 3(a)(7) of this table – the Goshen Area Asset Exchange, and (2) the commencement of network service as described in Section 3(b)(1).
4.	***IPC & BPA & PAC*** ***New Agreement:*** ***Longhorn Substation Agreements*** ***Prepare First Draft – BPA: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	IPC and PAC will fund a portion of the proposed Longhorn substation near Boardman, Oregon, if B2H interconnects at Longhorn. This funding will occur as specified in one or more negotiated Longhorn Substation Agreements between the Parties that is consistent with BPA's Line and Load Interconnection Business practices and allows for recovery of the network portion of these funds through incremental transmission wheeling revenue. The agreement will: a. include provisions for IPC and PAC to pay a use of facilities charge or other charge pursuant to BPA's OATT and applicable rate schedules to transact across the Longhorn bus in the future; b. include provisions for IPC and PAC to potentially own, operate and maintain B2H equipment, which shall include: the

		B2H series capacitor at Longhorn, the B2H shunt line reactors at Longhorn, any ancillary equipment required to support those devices, such as switches, bypass breakers (series cap), and insertion breakers (shunt reactor); and c. be contingent upon BPA completing its obligations and responsibilities under NEPA, NHPA, and other requisite environmental compliance laws and making a decision regarding how to proceed (including provisions for IPC and PAC funding upfront at a prorated amount based on cost allocation of Longhorn, BPA's NEPA, NHPA, and environmental compliance costs). Non-binding cost estimates identified for the potential Longhorn aspects of the B2H Project as of the Effective Date of this Term Sheet are as follows, which all Parties acknowledge and agree are preliminary and may be modified and revised prior to and upon B2H energization: *These are estimated costs, charges to be trued up with actual costs.* a. Longhorn (base substation) network costs ~\$59M. Costs subject to transmission credit. i. IPC 21% ~ \$12M (BPA to cover up to \$14M of IPC cost) ii. PAC 55% ~ \$33M iii. BPA 24% ~ \$14M (plus IPC ~ \$12M, for total ~ \$26M) b. B2H connection to Longhorn Network Bay~\$11M. Constructed/Owned/Maintained by BPA. Develop bay 3 with (2) 500kV circuit breakers & (5) 500kV disconnects. Costs subject to transmission credits. i. IPC & PAC 100% c. Customer built (not subject to transmission credits). Including civil work with the reactor and cap costs.

5.	***IPC & PAC*** ***New Agreement:*** ***Purchase and Sale Agreement for Asset Exchange -potentially utilize the previously developed Joint Purchase and Sale Agreement*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 4 of Calendar Year 2022***	PAC and IPC would purchase and sell to each other various assets to achieve the objectives identified in Section 3(a)(6) and Section 3(a)(7) of this table. PAC and IPC will seek to first balance the purchase and sale of the transferred assets through the depreciated net book value of such assets and allocation of upgrade costs and, finally, if necessary, will be balanced between IPC and PAC through cash considerations. <u>Details related to Populus – Four Corners assets</u>: These assets will provide IPC ownership on the existing PAC transmission system from Four Corners substation in New Mexico to Populus substation in Idaho. This will include 345 kV transmission lines between the following substations and assets to create a path through each substation: Four Corners, Pinto, Huntington, Camp Williams, Mona, Terminal, 90th South, Ben Lomond and Populus. Consistent with federal processes, IPC and PAC will complete required studies to determine if recent system upgrades result in a possible increase in existing transmission capacity between Borah and Populus to facilitate IPC's incremental transfer needs associated with this exchange. If determined necessary, IPC and PAC will identify revisions to the JOOA (as defined in Section 3(a)(6) of this table), upgrades, modifications, or other options to meet each party's commercial needs between Borah and Populus. <u>Details related to Borah/Kinport to Hemingway and Midpoint to Borah/Kinport assets</u>: These assets will provide PAC ownership on the existing IPC transmission system from Borah/Kinport to Hemingway and from Midpoint 500 to Borah/Kinport. This will include 500 kV and 345 kV transmission lines between the following substations and assets to create a path through each substation: Borah, Kinport, Adelaide, Midpoint and Hemingway. Upgrades are required across the Borah West and Midpoint West paths to facilitate this portion of the

		proposed asset exchange transaction. The cost of these upgrades will be determined in the course of negotiating the proposed asset exchange transaction described in this Section 3(a)(5). <u>Details related to Goshen Area assets</u>: As described in more detail in Section 3(a)(7) of this table, PAC will transfer to IPC certain to-be-determined Goshen areas transmission assets that would allow IPC to provide transmission service to all BPA customers in southeast Idaho currently served by PAC. These assets are being transferred to IPC, from PAC, as part of the negotiations between PAC and BPA as described in Section 3(a)(1) of this table, with the consideration for these assets being the transmission service provided by BPA to PAC as detailed in Section 3(a)(1) of this table. IPC and PAC intend for these Goshen assets to be incorporated into the broader purchase and sale agreement described in this Section 3(a)(5) with a goal of minimizing changes to each company's transmission rate base. This goal is intended to be facilitated through the allocation of the costs associated with the Borah West and Midpoint West upgrades.
6.	***IPC & PAC*** ***Amendment to Existing Agreement:*** ***IPC – PAC Joint Ownership and Operating Agreement ("JOOA")*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 4 of Calendar Year 2022***	As part of a transaction transferring assets described in Section 3(a)(5) of this table, IPC and PAC may expand their existing Joint Ownership and Operating Agreement, as amended and restated August 22, 2019 ("JOOA"), to include the following: I. PAC owning 300 MW of west-to-east transmission assets between Midpoint 500 and Borah (transferred from IPC); and II. PAC owning an additional 600 MW of east-to-west transmission assets between Borah and Hemingway (transferred from IPC) - total increases from the current 1,090 MW to 1,690 MW; and III. IPC owning 200 MW of bi-directional transmission assets between Populus, Mona and Four Corners (transferred from PAC); and IV. Other revisions as necessary to facilitate other asset exchanges (*e.g.*, for Goshen area, as

		described in Section 3(a)(5) and Section 3(a)(7) of this table).
7.	***IPC & PAC*** ***Goshen Area Asset Exchange*** ***Part of 3(a)(5)***	As referenced in Section 3(a)(5) and Section 3(a)(6) of this table, IPC and PAC would negotiate an asset exchange to be effective no later than (i) energization of the B2H line and (ii) commencement of the NITSA between BPA and IPC, as referenced in Section 3(b)(1), that enables BPA to to serve its loads currently in PAC's East transmission system (Lower Valley Elec., Idaho Falls, Fall River Rural Elec., Lost River Electric, Salmon River Electric, Soda Springs,) ("Southeast Idaho Load Service (SILS) Customers") with one leg of firm IPC network transmission service. As referenced in Section 3(a)(6) of this table, the Goshen area asset exchange may be wrapped into the existing JOOA framework. IPC, PAC, and BPA agree to make best efforts to plan for service to Idaho Falls that requires only one leg of network transmission from the BPA transmission system, provided such best efforts among the Parties must (1) respect and retain the existing services arranged for Idaho Falls load service between BPA and Utah Associated Municipal Power Systems (UAMPS); and (2) be in line with FERC orders in similar circumstances and accepted by FERC.
8.	***IPC & BPA*** ***New Agreement:*** ***Point to Point TSA*** ***Prepare First Draft – BPA: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	IPC will acquire up to 500 MW of PTP transmission service from Mid-C to Longhorn subject to the terms of BPA's OATT, business practices and applicable rate schedules. The duration of the new service must be for an initial service duration of at least 5 years, and sufficient to compensate BPA for BPA's revenue requirement associated with BPA capital investments to facilitate the transmission service, with the right to rollover service in accordance with the BPA's OATT and business practices in effect at the conclusion of the initial term.

9.	***IPC & PAC***	Upon energization of the B2H Project, PAC would not renew its current 510 MW of east-to-west rights on the IPC system (which rights are found in IPC 1st Revised Service Agreement (SA) Nos. SAs 344-346 and 383-384). Consistent with and pursuant to IPC's OATT, PAC and IPC will coordinate to extend any remaining IPC SAs, enter into new SAs, or take other action as necessary to bridge any SA expiration dates until such time as the B2H project is in-service.
10.	***IPC & PAC*** ***B2H Construction Funding Agreement-related Commitments***	The B2H Construction Funding Agreement, between IPC and PAC as referenced in Section 3(d) below, and any additional agreements as the Parties determine necessary, will include terms necessary to implement the Agreement to Reimburse BPA's Removal and Replacement Related Transaction Costs, among IPC, PAC and BPA, dated March 18, 2020 (BPA Contract No. 20TX-16835). IPC, on behalf of the B2H Project, will assure that it coordinates construction of the B2H Project with BPA in a manner consistent with the terms of BPA's Use Agreement, as amended by Amendment Two (2) to NF(R)-9617, including Exhibits A, B and C, between the United States of America, Dept. of the Navy and the United States of America, Bonneville Power Administration Ptn Secs 13, 23 and 24-T2N-R25E, W.M. IPC and PAC acknowledge that the Removal and Replacement Related Transactions described in Contract No. 20TX-16835 are contingent upon (1) BPA obtaining acceptable service from Umatilla Electric so that BPA may continue to serve Columbia Basin Electric's load; (2) BPA completing its obligations and responsibilities under NEPA, NHPA, or other requisite environmental compliance laws and making a decision regarding how to proceed; and (3) IPC and PAC moving forward with construction of the B2H Project.
11.	***IPC & PAC & BPA***	In conjunction with the termination of the NITSAs identified in Section 3(a)(3) of this table (*i.e.*, PAC

	BPA Redirect and Assignment of existing PTP transmission service ***Incorporate into Agreement on Principles and Timelines under 3(a)(1)***	SAs 746 & 747), following the energization of B2H, BPA will redirect its two 100 MW PTP transmission service agreements (91629850 and 91629500, or any applicable AREFs that supersede or replace them) that it takes from IPC (*i.e.*, IPC 1st Revised SAs 324 & 342) such that the new POR of each SA will be Walla Walla and the new POD for each SA will be Borah. Consistent with and pursuant to IPC OATT, following approval of such redirects by IPC as described above, BPA will assign those redirected reservations to PAC. This redirect and assignment will be delayed by BPA if B2H energization is delayed past 07/01/2026. PAC shall be responsible to pay for all costs associated with 91629850 and 91629500, or any applicable AREFs that supersede or replace them, upon approval of such redirect by IPC and assignment by BPA.
12.	***IPC & PAC & BPA, with respect to B2H Plus Facilities Expectations*** ***IPC & PAC, with respect to B2H Construction Funding Agreement***	The B2H Project will include the installation of the B2H Midline Series Capacitor Project and development of a remedial action scheme ("RAS"). When considering BPA's study methodology, the B2H midline series capacitor reduces simultaneous interactions between the NW AC Intertie, central and southern Oregon load service, and WECC Path 14 (Idaho to Northwest). The Parties agree to funding of the B2H Midline Series Capacitor Project as follows: a. IPC: funding 45% of the cost. b. PAC: funding 55% of the cost c. BPA: funding 0% of the cost The Parties will work in good faith to have the B2H Midline Series Capacitor Project in-service when the B2H Project is energized and to document expectations of operation, maintenance, and future reinforcements and upgrades.
13.	***IPC & PAC*** ***B2H Grant or Additional Funding***	Under IPC and PAC's existing OATT rate procedures, IPC and PAC will include any United States Department of Energy ("DOE") grant or additional funding received for the B2H project in the appropriate FERC account provided such account is allocated 100% to Transmission. Nothing in this Term Sheet limits or waives any party's right to participate, review, comment, or challenge the other

		party's rate case or formula rate inputs through their respective update processes.
14.	***IPC & PAC & BPA*** ***Permit Funding Agreement Amendment***	Upon transfer of BPA's Permitting Interest to IPC identified in 3(b)(3) below, the Permit Funding Agreement will be amended to recognize the re-allocation of the Parties' Permiting Interests and related funding obligations.

b) <u>NITSA Terms and Conditions, NITSA Security Agreement, NITSA Backstop</u>

1.	***IPC & BPA*** ***New Agreements:*** ***Network Integration Transmission Service Agreement to serve BPA customers at Goshen*** ***Network Integration Transmission Service Agreement to service BPA's customer at Burley*** ***Amendment to currently effective Network Integration Transmission Service Agreements*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022***	IPC and BPA will enter into two NITSAs for IPC to provide firm network transmission service to BPA. One NITSA will serve BPA customers at Goshen (replacing what is, as of the Effective Date of this Term Sheet, provided under PAC Service Agreement 746) and one NITSA will serve Idaho Falls (replacing what is, as of the Effective Date of this Term Sheet, provided under PAC Service Agreement 747) ("New NITSAs"). The New NITSAs will be in addition to the existing NITSAs BPA currently holds with IPC for service to BPA's customers located on IPC's system ("Existing NITSAs"). The term of BPA's New NITSAs will be 20-years from energization of the B2H Project, with a renewal or rollover option at BPA's discretion as required and permitted by FERC a. The NITSA Security Agreement (as referenced in Section 3(b)(2) of this table), and any related other agreements necessary, between BPA and IPC will be updated once the energization of B2H has occurred to document the term and the repayment periods with the actual energization date. b. The New NITSAs, NITSA Security Agreement, and any related other agreements necessary, are conditioned on the Goshen Area Asset Exchange set forth in Section 3(a)(7) being completed and all associated agreements being in effect by the energization of the B2H line.

	Target Execution Date: Quarter 3 of Calendar Year 2022	The New NITSAs and the Existing NITSAs will be updated to include three Points of Receipt (PORs) over which BPA can deliver energy to its customers located on IPC's system. The three PORs are as follows: AMPS POR, LaGrande POR, and Longhorn POR. The New NITSAs shall reflect the following provisions: a. Under the New NITSAs, IPC will plan for and reserve transmission capacity for the continued network service to BPA's SILS Customers' loads and ensure that it can reliably serve the load for the term of the contract prior to BPA assigning the PTP service agreements to PAC pursuant to Section 3(a)(11) above. b. The New NITSAs between BPA and IPC will permit BPA to assign service to specific Points of Delivery (PODs) to BPA's wholesale customers who take service at those PODs. Such assigned PODs will be served by a separate NITSA agreement between BPA's wholesale customer and IPC. The New NITSA between BPA and IPC will state that the customer requesting a separate NITSA for its POD must meet credit rating standards consistent with IPC's OATT. Notwithstanding assignment of the NITS service, BPA would remain entitled to all outstanding credits associated with the Funded Amounts (as defined in Section 3(b)(2) below) as long as BPA continues to be a NITS customer. c. IPC will maintain the current practice of letting BPA choose through the annual delivery allocation process the PODs where BPA will deliver power to serve its loads. The current PODs include LaGrande and AMPS. Once B2H is in service, the PODs will include LaGrande, Longhorn, and AMPS. d. BPA would pay the NT rate as established by IPC's OATT transmission formula rate. There shall be no adders or segmentation

		like actions which result in a rate above the NT rate and the amount BPA pays to IPC under the NT service agreement will be reduced as discussed in the NITSA Security Agreement. e. IPC will not charge BPA IPC's system losses for energy from BPA's Palisades resource used to serve load behind Goshen.
2.	***IPC & BPA*** ***New Agreement:*** ***NITSA Security and Risk Backstop Agreement*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	IPC and BPA will enter into an NITSA security and risk backstop agreement ("NITSA Security Agreement"), concurrently with the New NITSA and the purchase and sale agreement referenced in Section 3(b)(3) of this table. <u>Reimbursement If IPC Receives all Permits and Certificates of Public Convenience and Necessity (CPCN) for Construction of B2H</u> IPC will reimburse BPA for the transfer of BPA's Permitting Interest under the Joint Permitting Agreement in an amount consisting of BPA's investment in B2H prior to the transfer date (~$25m). BPA will also pay to IPC an additional $10 million upon execution of the New NITSAs and the NITSA Security Agreement with the intent of offsetting overall B2H project costs in IPC's rate base. The additional $10 million plus BPA's investment in B2H will be collectively referred to as the "Funded Amount." IPC will retain the Funded Amount as follows: If and when IPC obtains all necessary CPCNs and permits for the B2H Project (and all appeals, if any, have been resolved), IPC shall have until January 1, 2026 ("Commencement Date") to commence construction of B2H or to inform BPA of its intent to not pursue construction of B2H. (1) If IPC commences construction of B2H by or before the Commencement Date, then: a. Interest on the Funded Amount (~$35m) payable by IPC to BPA will accrue from the date of energization of B2H at the rate

		established in the applicable IPC tariff for customer funded projects; b. The Funded Amount and all accrued interest will be repaid to BPA starting year 11 following the energization date (the "Refund Commencement Date"), with repayment amortized over the remaining 10 years of the New NITSAs. i. IPC and BPA will incorporate the interest schedule and payment amortization as an exhibit to the NITSA Security Agreement; ii. If during the term of the New NITSAs BPA defaults on its payment obligations under the New NITSAs, IPC will be entitled to retain for its own account an amount equal to the defaulted payment obligation not to exceed the amount not reimbursed to BPA as of the default date; iii. BPA will not be considered in default for any amount not paid subject to a billing dispute; and iv. IPC may prepay the Funded Amount and interest thereon at any time without penalty. (2) If IPC does not commence construction of B2H by or before the Commencement Date or if IPC informs BPA before the Commencement Date of its intent to not proceed with B2H, then: a. IPC shall have 180 days from the Commencement Date (or notice to BPA of its intent to not proceed, whichever is earlier) to sell its Permitting Interests in the B2H Project; b. No later than the close of the above mentioned 180 days, IPC shall i. pay to BPA BPA's proportional share of any proceeds received from the sale of its Permitting Interest in the B2H Project (if any), and

		ii. Pay to BPA the $10 million BPA provided to IPC upon execution of the New NITSAs. <u>Risk Backstop if IPC does not Receive all Permits or CPCNs Necessary for constructing B2H.</u> If IPC does not obtain all necessary CPCNs and permits for the B2H Project, or any such CPCNs or permits are overturned on appeal, then (a) IPC will return to BPA the $10 million BPA provided to IPC upon execution of the New NITSAs; and (b) BPA will reimburse IPC for funding the additional 24.24% share of all B2H Permitting and Preconstruction Costs incurred after BPA transfers its 24.24% Permitting Interest to IPC. The reimbursement obligation will not include any costs related to Right of Way option acquisition or exercising Right of Way Options. The risk backstop commitment will remain in place until IPC obtains all necessary CPCNs and permits for the Project (and all appeals, if any, have been resolved). The intent of the backstop is only to assist IPC in mitigating the risk associated with receiving the approvals for the B2H Project; not to assist in mitigating business risk. The risk backstop commitment will be as follows: a. IPC will not compensate or reimburse BPA for costs expended by BPA on B2H prior to the transfer of the Permitting Interest to IPC (*i.e.*, ~$25m BPA has expended to date); b. BPA will reimburse 24.24% of actual B2H Project Permitting Costs incurred after IPC takes over funding 45% of the project. (Current estimates for 2021-2024 – Total B2H Project estimated at $9,125,466 with 24.24% of these costs estimated at $2,212,234); and c. BPA will reimburse 24.24% of actual B2H Project Pre-Construction Costs incurred after IPC assumes funding 45% of the project. (Current estimates for

		2021-2024 – Total B2H Project estimated at $9,403,564 with 24.24% of these costs estimated at $2,279,652). Collectively, these amounts set forth in a. through c. above will be the "Risk Backstop Amount." The Risk Backstop Amount will be adjusted, as necessary, to the extent that IPC receives grants or forms of other financial assistance from sources other than BPA or PAC. For example, if IPC received a government grant that defrayed the pre-construction costs of B2H, BPA's 24.24 % share of the pre-construction costs would be reduced accordingly.
3.	***Transfer of Interest in Joint Permitting Agreement:*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	IPC and BPA will execute a purchase and sale agreement, assignment, and other applicable transfer documents, concurrently with the New NITSAs, NITSA Security Agreement, and any related other agreements necessary, to transfer all of BPA's Permitting Interest under the Joint Permitting Agreement (and all of BPA's interest in the assets associated therewith) to IPC in exchange for IPC's agreement for repayment to BPA of BPA's investment in B2H through the Joint Permitting Agreement through the effective date of the definitive purchase and sale agreement contemplated in this Section 3(b) (or other date specified therein). The proposed purchase and sale agreement contemplated in this Section 3(b)(3) will contain representations, warranties, and covenants typical of a transaction of the nature contemplated by these proposed terms. The definitive agreements transferring BPA's Permitting Interest under the Joint Permitting Agreement and related assets will be executed prior to any activities BPA has indicated could impact federal environmental regulatory requirements under NEPA, so as to prevent additional delay in the development of B2H. Following the transfer of BPA's Permitting Interest (and associated assets) under the Joint Permitting Agreement to IPC, IPC will be solely responsible for funding an additional 24.24% share of all B2H Project Costs thereafter under Joint Permitting Agreement

		(which includes permitting and preconstruction costs), and IPC will be entitled to all rights, title, and interests and assets that BPA would otherwise obtain under the Joint Permitting Agreement if it were a remaining funding party thereto.

c) Ownership, Operation, and Maintenance Agreement: Defines IPC's and PAC's capacity and property ownership, and their roles and responsibilities for operating and maintaining the B2H Project ("***Ownership and Operation Agreement***"). IPC will prepare an initial draft of the Ownership and Operation Agreement based on the ownership interests below and otherwise consistent with the terms of the JOOA between IPC and PAC. Alternatively, in lieu of a new agreement, IPC and PAC may decide to amend the existing JOOA to cover the B2H Project assets.

Idaho Power	**PacifiCorp**	**BPA**
Project ownership: 45.45%	Project ownership: 54.55%	Project ownership: 0%

d) Construction Funding Agreement: Defines IPC's and PAC's roles and responsibilities in construction of the B2H Project ("***Construction Funding Agreement***"). IPC will prepare an initial draft of the Construction Funding Agreement consistent with the following terms:

1. Project In-Service Date	June 1, 2026
2. Scope	The Construction Funding Agreement covers all work necessary to construct the B2H Project by the Project In-Service Date, including any associated residual work after the Project In-Service Date, but excluding any work already covered by the Joint Permitting Agreement.
3. Project Delivery System	A competitive process is being completed to hire a Construction Manager / Constructability Consultant ("CM") for the B2H Project in 2022 to: (1) provide constructability feedback to the design engineer; and (2) collaborate with PAC and IPC to complete the BLM Construction Plan of Development and the Oregon Energy Facility Siting Council's Site Certificate amendments. The hiring process of the CM will be structured such that the CM may be retained to construct the B2H Project.

	IPC and PAC may mutually agree to modify the CM's role through the Construction Funding Committee (as defined in Section 10 below -***Project Funding and Committee***) without amending the Construction Funding Agreement.
4. Project Manager	IPC is the overall Project Manager for all B2H Project permitting, design, procurement, construction, except that BPA will be responsible for designing, procuring, and constructing the Longhorn substation as described in Section 3(a)(4) and relocating and replacing the BPA 69 kV line off Navy property as described in Section 3(a)(10). Although IPC is the Project Manager, PAC is not precluded from taking project management responsibilities for all or selected tasks associated with the B2H Project; provided that these delegations must be made by the Construction Funding Committee.
5. Construction Project Manager	IPC's role as Construction Project Manager will be generally consistent with the roles and responsibilities of the Permitting Project Manager set forth in Article IV of the Joint Permitting Agreement, provided that the permitting responsibilities not relevant to construction will be removed. IPC, as the Construction Project Manager, will provide monthly project updates, including updates on project activities, financials, forecasts, and invoices detailing costs incurred with breakdowns demonstrating all Parties' cost responsibilities based on their percentage shares. To provide the necessary flexibility to avoid delay/additional costs, the Construction Project Manager will administer and oversee all work necessary to construct the B2H Project within the approved budget, schedule and scope, and also have authority to approve any non-material changes to the B2H Project resulting in a price difference of less than $500k, so long as the overall B2H Project costs remain within the approved budget with the price change. All changes to the B2H Project resulting in a change in the approved budget, will require approval of the Construction Funding Committee.

6. Component Specifications	All B2H Project construction specifications shall meet or exceed all applicable state and federal design requirements and standards; provided that, such specifications may be modified by the Construction Funding Committee so long as the project complies with all applicable state and federal design requirements and standards.
7. Real Property Ownership	<u>B2H real property, except Longhorn substation</u>: IPC will acquire rights of way, grants, easements, or other interests in real property necessary to construct, operate and maintain the B2H transmission line and grant to PAC perpetual and sufficient rights of access, to be set forth in the Ownership and Operation Agreement. <u>Longhorn Substation</u>: Upon completion of BPA's obligations and responsibilities under NEPA, NHPA, and other requisite environmental compliance laws and if BPA decides to proceed with construction of Longhorn substation, BPA will continue to own all real property associated with the Longhorn substation, and in relation to the B2H Project equipment BPA shall grant to IPC and PAC perpetual and sufficient rights of access, to be set forth in one or more Longhorn Substation Agreements as described in Section 3(a)(4).
8. Equipment and Facilities Ownership	Equipment and facilities ownership will be consistent with the Ownership and Operation Agreement. <u>B2H equipment/facilities, except Longhorn substation</u>: IPC and PAC will jointly own as tenants in common the transmission line and all associated facilities and equipment, including all associated facilities located in Hemingway Substation as well as supporting communication facilities and B2H Project substation equipment. <u>Longhorn Substation</u>: Upon completion of BPA's obligations and responsibilities under NEPA, NHPA, and other requisite environmental compliance laws and if BPA decides to proceed with construction of Longhorn substation, BPA will own all equipment and facilities in the Longhorn substation, except the B2H specific equipment and facilities which will be jointly owned by IPC and PAC as tenants in common. BPA will grant IPC and PAC access rights to the equipment

	and facilities in Longhorn substation that are constructed as part of and necessary to the operation of the B2H transmission line facilities, to be set forth in one or more Longhorn Substation Agreements as described in Section 3(a)(4).
9. Material Procurement	All material specifications shall be in accordance with IPC's procurement policies and standards, unless otherwise agreed by the Construction Funding Committee to exceed the same.
10. Project Funding and Committee	Funding: IPC and PAC will fund the B2H Project consistent with their respective ownership shares. Construction Funding Committee: The Construction Funding Agreement shall create a Construction Funding Committee consistent with IPC and PAC's ownership interests in the B2H Project, and generally consistent with the Permit Funding Committee created by the Joint Permitting Agreement (Article III). The Project Manager's reporting requirements set forth in the above Section 5 (***Construction Project Manager)*** will be delivered to all members of the Construction Funding Committee prior to, and discussed during, each of the Committee's regularly-scheduled monthly meetings. Obligations, disputed amounts, and audit rights will be generally consistent with Article III of the Joint Permitting Agreement. The Project Manager will have flexibility to make day-to-day decisions associated with construction of the Project but will be required to seek resolution/approval from the Construction Funding Committee on larger dollar/impact decisions, consistent with that set forth in the above Section 5 (***Construction Project Manager***). BPA will be responsible for designing, procuring, and constructing the Longhorn substation as described in Section 3(a)(4) and relocating and replacing the BPA 69 kV line off Navy property, as described in Section 3(a)(10).
11. Payment Schedule	Costs Accrued Prior to Agreement Execution: Prior to executing the Construction Funding Agreement, IPC

	and PAC will have the opportunity to audit all accrued construction-related expenses included therein that have not otherwise been funded under the Joint Permitting Agreement. IPC and PAC will align on ownership shares prior to execution of the Construction Funding Agreement and pay their respective portions of accrued expenses within 30 days of the effective date of the Construction Funding Agreement. Until which time BPA fully divests its ownership interest in the B2H Project, the Parties acknowledge that the B2H Project is bound to compliance with NEPA, NHPA, and other environmental laws associated with federal agency action. Costs Incurred After Execution: Following execution of the Construction Funding Agreement, the Project Manager will invoice the Construction Funding Agreement participants monthly, requiring payment within 30 days of the invoice date.
12. Transfer/Assignment of Rights/Interests *(Some or all of these terms may be instead placed in the Ownership Agreement)*	IPC and PAC may sell some or all of their respective ownership interests in the B2H Project, together with associated capacity, subject to the Construction Funding Committee's agreement and approval of the terms of any such transaction; provided that, such approval will not be unreasonably withheld. IPC will not transfer or assign rights or interests in the B2H Project that would materially impact the BPA load service commitments set forth in Section 3(b) of this Term Sheet.
13. Term ***Early Termination*** ***Withdrawal***	Term: The term of the Construction Funding Agreement will extend through completion of B2H Project construction, as well as final billing and any reconciliation or mitigation associated with the final expenses, unless otherwise agreed by the Construction Funding Committee. Early Termination/Withdrawal: Absent approval of the Construction Funding Committee, no Party shall have a right to withdraw from the Construction Funding Agreement following the earlier of (1) awarding the B2H Project construction contract, or (2) commencing procurement of long-lead items and equipment.

	Assignments of IPC's or PAC's rights and obligations under the Construction Funding Agreement shall be managed pursuant to the above Section 12 (***Transfer/Assignment of Rights/Interests***).
14. Event of Default	Generally consistent with Article VIII of the Joint Permitting Agreement.
15. Force Majeure	Generally consistent with Article IX of the Joint Permitting Agreement.
16. Reps and Warranties	Generally consistent with Article X of the Joint Permitting Agreement.
17. Common Defense & Limitation of Liability	Generally consistent with Article XI of the Joint Permitting Agreement, except that the Article will be expanded to address construction claims.
18. Proprietary Information/Confidentiality	Generally consistent with Article XII of the Joint Permitting Agreement, except that the Article will provide IPC the ability to share information as necessary to work with potential and selected engineers and contractors.
19. Dispute Resolution	Generally consistent with Article XIII of the Joint Permitting Agreement.
20. Miscellaneous	Generally consistent with Article XIV of the Joint Permitting Agreement and including any standard terms that are necessary for PAC agreements (e.g. assignment and jury trial waiver provisions).

4. Additional Agreements. The Parties agree that they may consolidate any or all of the above-described Agreements and are not precluded from pursuing additional agreements, or amending existing agreements as needed, related to the B2H Project besides those discussed herein.

5. Expenses. Each Party will bear its own expenses (including attorneys' fees) incurred in connection with preparation, negotiation, and execution of this Term Sheet, including preparation, negotiation and execution of the Agreements described herein.

ACKNOWLEDGED AND AGREED TO BY THE PARTIES:

IDAHO POWER COMPANY

Signature: Ryan N. Adelman

Printed Name: RYAN N ADELMAN

Title: VP, POWER SUPPLY

Date: 1/18/22

PACIFICORP

Signature: Rick Link Digitally signed by Rick Link Date: 2022.01.18 11:11:21 -08'00'

Printed Name: Rick Link

Title: Senior Vice President, Resource Planning, Procurement and Optimization

Date: 01/18/2022

Signature: Rick Vail Digitally signed by Rick Vail Date: 2022.01.18 11:59:50 -08'00'

Printed Name: Rick Vail

Title: Vice President, Transmission

Date: 01/18/2022

BONNEVILLE POWER ADMINISTRATION

Signature: TINA KO Digitally signed by TINA KO Date: 2022.01.18 04:25:04 -08'00'

Printed Name: Tina Ko

Title: Vice President, Transmission Marketing a

Date: 1/18/2022

Signature: Digitally signed by KIM THOMPSON Date: 2022.01.18 07:32:28 -08'00'

Printed Name: Kim Thompson

Title: Vice President, Requirements Marl

Date: 1/18/2022

REDACTED
Docket No. 20000-___-EN-23
Witness: Rick A. Vail

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Rick A. Vail

February 2023

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp.

A. My name is Rick A. Vail. My business address is 825 NE Multnomah Street, Suite 1600, Portland, Oregon 97232. My present position is Vice President of Transmission. I am responsible for transmission system planning, customer generator interconnection requests and transmission service requests, regional transmission initiatives, asset management, capital budgeting for transmission, and administration of the Company's Open Access Transmission Tariff ("OATT"). I am testifying on behalf of PacifiCorp d/b/a Rocky Mountain Power (the "Company").

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science Degree with Honors in Electrical Engineering with a focus in electric power systems from Portland State University. I have been employed at the Company since 2001, and have had a range of management responsibility within the asset management group, including capital planning, maintenance policy, maintenance planning, and investment planning. I served as Director of Asset Management from 2007 to 2012. I became Vice President of Transmission in December 2012.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony supports the Company's application for waiver or approval of a non-situs certificate of public convenience and necessity ("CPCN") for Energy Gateway Segment H, the Boardman to Hemingway 500-kilovolt ("kV") transmission line ("B2H" or the "Project"). My testimony also supports waiver or approval under the advanced review process set forth in the stipulation approved in Docket

No. 20000-384-ER-10, Record No. 12702 ("Advanced Review Process").

B2H is an approximately 300-mile-long 500-kV electric transmission line with a western terminal at a proposed new switching station near Boardman in north-central Oregon and an eastern terminal at the existing Hemingway substation in southwest Idaho. Twenty-four miles of B2H will be located in Owyhee County in Idaho with an additional 274 miles located in five Oregon counties: Malheur, Baker, Union, Umatilla, and Morrow Counties. The Project consists of:

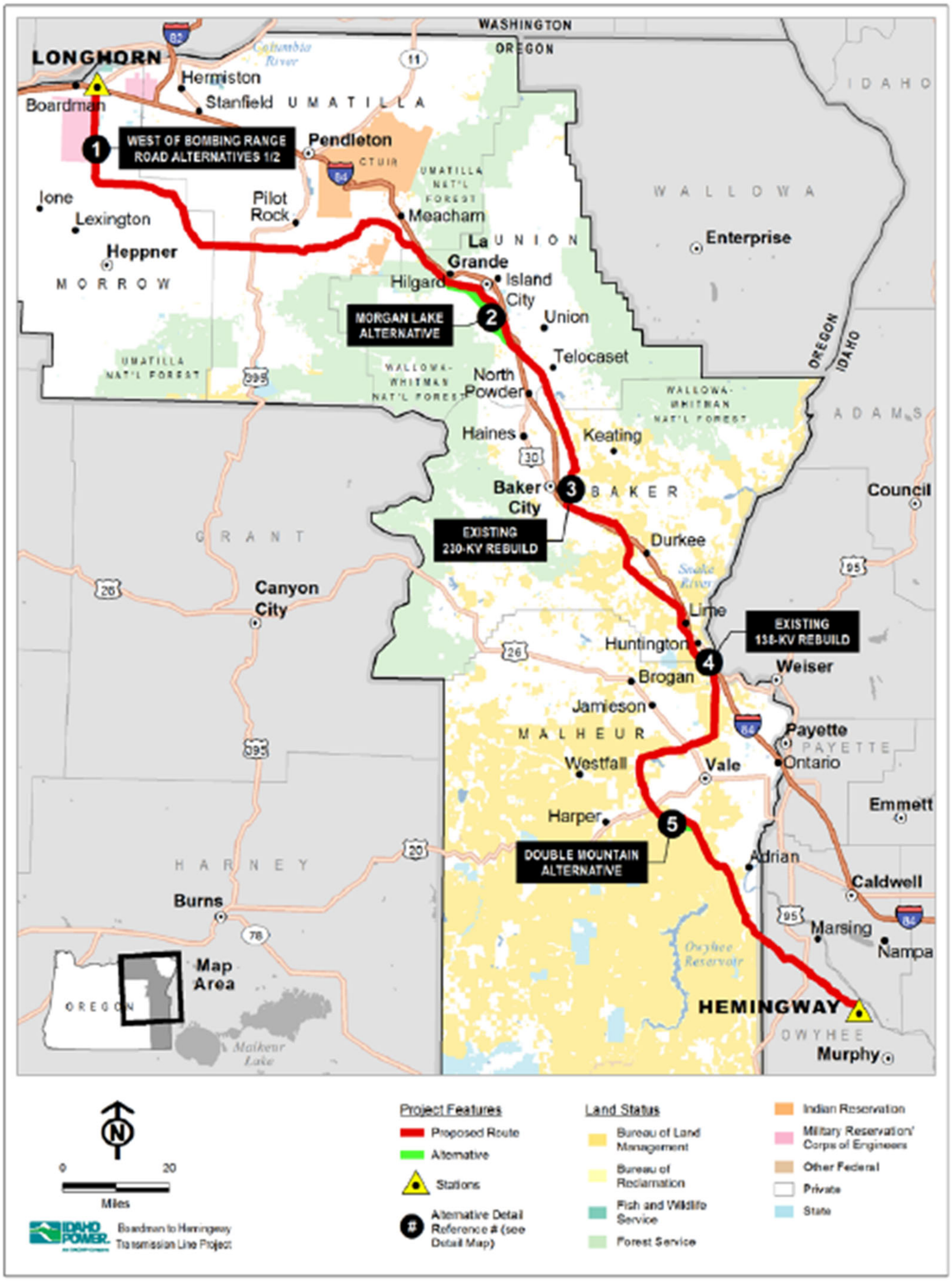
1. Construction of approximately 274 miles of single-circuit 500-kV transmission line in Oregon;
2. Construction of approximately 24 miles of single-circuit 500-kV transmission line in Idaho; and
3. Removal of 12 miles of existing 69-kV transmission line.

Additionally, construction of B2H will require the following ancillary facilities:

1. A newly constructed switching station proposed to be constructed near Boardman, Oregon;
2. Construction of the Midline Series Capacitor substation;
3. Ten communication stations constructed within the right-of-way of the transmission line;
4. Construction of approximately 206 miles of new access roads; and
5. Substantial modification of approximately 223 miles of existing roads.

The following graphic, which Idaho Power Company ("IPC") prepared in its application for a site certificate from Oregon's Energy Facility Siting Council

("EFSC"), shows the general location of B2H, including the alternative route segments approved by EFSC:



My testimony and exhibits provide information required by Wyoming Public Service Commission ("Commission") Rules Chapter 3, Section 21(c)(i), Wyoming

Statute § 37-2-205.1, related to applications for CPCNs, and information for the Advanced Review Process.

Q. Please summarize your testimony.

A. B2H is necessary, reasonable, and in the public interest. The Project is necessary for the Company to meet its customers' short- and long-term energy demand and will strengthen the overall reliability of the existing transmission system. While B2H has long been recognized as an integral component of the Company's long-term transmission planning, its construction by 2026 is both necessary and beneficial for customers, as B2H will enable the Company to efficiently deploy new generating facilities and better utilize existing resources to meet projected resource needs.

B2H will provide a much-needed transmission connection between the Company's eastern balancing authority area ("BAA"), PacifiCorp East ("PACE"), and its western BAA, PacifiCorp West ("PACW"). This connection is vital because currently the Midpoint-to-Summer Lake 500-kV transmission line is the only line connecting PACE and PACW. Increasing connections between the Company's BAAs will enable the Company to more efficiently serve customers in both areas using the most cost-effective generation available. Additionally, construction of B2H will provide regional benefits by strengthening the interconnected transmission grid in the West and enhancing resource adequacy.

In addition to construction of B2H, IPC and the Company have agreed to exchange several existing transmission assets. These asset exchanges will enable both the Company and IPC to develop more interconnected transmission systems to serve their respective customers. I discuss the asset exchanges and the agreements that the parties intend to execute to implement these exchanges below.

III. DESCRIPTION OF B2H

Q. Please briefly describe PacifiCorp's transmission system.

A. PacifiCorp owns and operates approximately 17,000 miles of transmission lines ranging from 46-kV to 500-kV across multiple western states. PacifiCorp has over two million customers with approximately 142,000 customers located in Wyoming. Wyoming is located (along with Idaho and Utah) in PacifiCorp's eastern BAA, PACE, which has over 12,640 circuit-miles of transmission lines and a record peak demand of 9,700 megawatts ("MW"). A new record peak was reached in PacifiCorp's overall system on July 28, 2022 at 13,195 MW. The PACE peak at that time was 9,290 MW.

Q. Is PacifiCorp's transmission system interconnected with any third-party systems?

A. Yes. PACE alone is interconnected with 17 other systems, including Arizona Public Service, Bonneville Power Administration ("BPA"), NV Energy, Los Angeles Department of Water & Power, NorthWestern Energy, Western Area Lower Colorado-Phoenix, IPC, Western Area Colorado Missouri-Loveland, Western Area Power Administration, Black Hills Power, Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Power Electric Cooperative, Basin Electric Power Cooperative, Intermountain Power Agency, Tri-State Generation & Transmission Association, and Public Service Company of New Mexico.

Q. Please describe B2H.

A. B2H is a high voltage single-circuit 500-kV alternating current transmission line that extends approximately 300 miles from north-central Oregon to southwest Idaho. B2H is also referred to as Segment H of Energy Gateway.

Q. Have the parties identified the necessary agreements for B2H?

A. Yes. On January 18, 2022, the parties executed a non-binding Term Sheet as the framework for future agreements, which is included as an exhibit to Mr. Rick T. Link's testimony. I discuss several of the agreements identified in the Term Sheet in detail below.

Q. Where does B2H begin and end?

A. B2H begins at the proposed Longhorn substation near Boardman, Oregon. From there B2H extends south and east through Morrow and Umatilla Counties before entering Union County. B2H parallels the corridor for Interstate 84 ("I-84") through Union and Baker Counties. In Malheur County, the route briefly turns to the southwest before finally returning southeast and eventually terminating at the existing Hemingway substation in Owyhee County, Idaho.

Q. Please describe B2H's proposed route.

A. After leaving the proposed Longhorn substation, the transmission line runs south for approximately 19 miles, paralleling existing transmission and pipeline rights-of-way for the first 13 of those miles. At that point, B2H turns east-by-southeast through Morrow and Umatilla Counties and enters Union County.

Beginning at approximately milepost 90, B2H begins to parallel the I-84 as it approaches the city of La Grande, Oregon. B2H roughly parallels I-84 for the next 110 miles through Union and Baker Counties.

Shortly after entering Malheur County, B2H turns south for approximately 12 miles primarily through land that is managed by the Bureau of Land Management ("BLM"). At approximately milepost 212 the transmission line turns to the southwest through agricultural and BLM land for approximately 14 miles. Finally, the transmission line turns to the southeast and continues primarily through BLM-managed lands. At approximately milepost 253, B2H enters the BLM's Vale District Utility Corridor, which the transmission line then follows for much of its remaining path through Malheur County as it approaches the Oregon-Idaho state line.

After crossing into Owyhee County, Idaho, the transmission line continues in a southeastern direction until finally terminating at the existing Hemingway substation.

Q. What types of towers and conductors will be used to construct B2H?

A. For the B2H project, structures will primarily be steel lattice tower structures, which provide an economical means to support large conductors for long spans over long distances. These lattice towers will range in height from 109 to 200 feet, with a typical structure height of 160 feet. In select areas tubular steel H-frame towers will be deployed with a height range of about 65 to 105 feet to mitigate potential impacts to visual resources. A structure will be located roughly every 1,400 feet on average.

For a single-circuit transmission line, such as B2H, power is transmitted via three phase conductors (a phase can also have multiple conductors, called a bundle configuration). These conductors are typically comprised of a steel core to give the conductor tensile strength and reduce sag of the aluminum outer strands. Aluminum is used because of its high conductivity to weight ratio. The conductors will have a non-specular finish to reduce visual impacts. Shield wires, typically either steel or aluminum and occasionally including fiber optic cables inside for communication, are the highest wires on the structure. Their main purpose is to protect the phase conductors from a lightning strike.

Q. Will B2H require modifications to any substations?

A. Yes. B2H will require construction of the proposed Longhorn substation near Boardman, Oregon. The existing Hemingway substation in Owyhee County, Idaho will also require upgrades. Finally, B2H will require construction of a Midline Series Capacitor substation.

Q. Please describe the proposed work at the Longhorn substation.

A. The western terminus for B2H requires the new Longhorn substation to tap into the existing BPA 500-kV transmission network. BPA owns the land for the Longhorn substation and intends to construct the substation to integrate certain wind projects in the immediate area once all environmental compliance laws are met. As agreed under the Term Sheet, BPA will own all equipment and facilities in the Longhorn substation, except B2H-specific equipment and facilities, which will be jointly owned by IPC and the Company.

Q. Please describe the proposed work at the Hemingway substation.

A. The IPC-owned existing Hemingway substation is designed to accommodate the B2H line terminal but will require the addition of new equipment. IPC, as project manager for construction of B2H, is responsible for these upgrades.

Q. Please describe the proposed work at the Midline Series Capacitor substation.

A. The Midline Series Capacitor substation is necessary to reduce simultaneous interactions between the Northwest ("NW") Alternating Current ("AC") Intertie, central and southern Oregon load service, and Path 14 (Idaho to Northwest). The Midline Series Capacitor station was added to the project scope between the 2019 Integrated Resource Plan ("IRP") and 2021 IRP to facilitate the operational needs of the parties, and at this time consists of only a fenced yard and series capacitor.

Q. Will any other stations be constructed as part of B2H?

A. Yes. Ten communication stations will be constructed along the route of B2H. These stations will be built within the right-of-way of the transmission line itself. The typical communication station site will be 100 feet by 100 feet, with a fenced area of 75 feet by 75 feet. A prefabricated concrete communications structure with dimensions of approximately 11.5 feet by 32 feet by 12 feet tall will be placed on the site and access roads to the site and power from the local electric distribution circuits will be required. A standby generator with a liquefied propane gas tank will be installed at the site inside the fenced area. Two separate conduit (underground) or aerial cable routes will be used for each fiber optic cable bundle between the transmission line and communication station. Conduits will be 2-inch-diameter polyvinyl chloride and will be buried three feet below the surface extending from the communication shelter to two different legs of the transmission structure maintaining a 10-foot separation between the cables. All work will occur within the disturbance footprint for either the communication station or the transmission structure to which the cables will attach.

Q. What is the total cost estimate for the Company's share of B2H?

A. The Company estimates that its in-service cost of B2H will be [redacted], including allowance for funds used during construction ("AFUDC"). This is the cost estimate used in the Company's economic analysis sponsored by Mr. Link.

Q. Has the Company put in place any cost controls for B2H?

A. While the Company and IPC have not yet finalized the definitive terms of the B2H construction funding agreements, the Company is working with IPC, the B2H project manager, to ensure provisions are put in place to control costs.

As explained in testimony IPC filed in support of its own application for a CPCN, IPC has strict project cost controls for internal and external personnel. Regular monthly forecast updates, including the tracking of budgets and schedules, are part of the project controls suite that the project management team employs. During the current preconstruction phase, IPC constructability consultant, Quanta Infrastructure Solutions Group, aided in certain preconstruction reviews and tasks. This early integration of the construction team allows for constructability feedback, identification of risks, and opportunities to economize the design. As the B2H project transitions into the construction phase, all material and construction services will be competitively bid and be pulled into a guaranteed maximum price ("GMP") that will serve as the construction pricing if awarded. This GMP is tied to a schedule that IPC and the construction manager will have developed together that IPC, in consultation with the Company, and as a result of the contract, the construction manager will be responsible for meeting that schedule. Milestone dates will be tied to monetary penalties for the construction manager if key dates slip.[1]

Q. Will the cost of B2H be included in PacifiCorp's transmission rates?

A. Yes. B2H will be considered a network transmission asset under the Company's OATT, and Federal Energy Regulatory Commission ("FERC") precedent for ratemaking supports rolling in the costs of these assets into the Company's transmission rates. Through inclusion in the Company's OATT, part of the costs of B2H will be recovered from third-party transmission customers and included as an offset to the benefit of retail customers.

Q. When does the Company expect construction of B2H to be complete?

A. As mentioned above, the Company expects construction to be completed by 2026.

IV. NECESSITY OF B2H

Q. What is the standard for issuing a non-situs CPCN in Wyoming?

A. I am not an attorney, but my understanding is that the Commission may issue a CPCN if an applicant demonstrates that the present or future need for the non-situs resource is prudent and in the public interest.[2]

Q. Does the Company have an identified need for the construction of B2H?

A. Yes. B2H is necessary for the Company to cost-effectively serve its growing Oregon loads. Additionally, B2H will increase grid reliability and increase transferability between PACE and PACW.

[1] *In re Idaho Power Company's Application for a Certificate of Public Convenience and Necessity for the Boardman to Hemingway 500-kV Transmission Line*, Case No. IPC-E-23-01, Direct Testimony of Lindsay Barretto at 40-41 (Jan. 10, 2023).
[2] Wyo. Stat. §37-2-205.1(a).

Q. Has the Company addressed the benefits of B2H in prior filings with the Commission?

A. Yes, the Company has identified the expected benefits of B2H in its IRPs, which are discussed in more detail in the testimony of Mr. Link. To continue to provide reliable and cost-effective service, the Company must invest in a robust transmission system to move resources across and between both PacifiCorp balancing areas. As Mr. Link explains in his testimony, B2H has repeatedly been identified as the most cost-effective means to serve customer demand.

Q. Has the Company further analyzed the cost benefits of B2H since the 2021 IRP?

A. Yes. The Company conducted extensive economic analysis of B2H in preparation for this CPCN filing. That analysis is summarized in the testimony of Mr. Link. As Mr. Link explains, the Company's recent economic analysis further supports the reasonableness of B2H.

Q. How does B2H enhance grid reliability?

A. The Hemingway-to-Summer Lake 500-kV transmission line currently is the only line connecting PACE and PACW.[3] The loss of the Hemingway-to-Summer Lake line has the potential to reduce transfers between the Company's BAAs by 1,090 MW. B2H will provide redundancy by adding an additional 1,000 MW of capacity between the Hemingway substation and the Pacific Northwest.

Because it is the only 500-kV connection between the Pacific Northwest and Idaho Power, the loss of the Hemingway-to-Summer Lake 500-kV transmission line

[3] PacifiCorp, 2021 IRP, Volume 1 at 90 (Sept. 1, 2021) (available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf) (last visited Jan. 25, 2023) [hereinafter "2021 IRP"].

during peak summer load is one of the most severe possible contingencies the Idaho Power transmission system can experience. Once Hemingway-to-Summer Lake 500-kV disconnects, the transfer capability of the Idaho to Northwest path is reduced by over 700 MW in the west-to-east direction. After the addition of B2H, there will be two major 500-kV connections between the Pacific Northwest and Idaho Power and as a result the Hemingway-to-Summer Lake 500-kV outage would become much less severe to Idaho Power's transmission system.

Additionally, under current conditions the loss of the Hemingway-to-Summer Lake 500-kV line with heavy east-to-west power transfer out of Idaho to the Pacific Northwest would result in significant system impacts. In this disturbance, an existing remedial action scheme (power system logic used to protect power system equipment) would disconnect over 1,000 MW of generation at the Jim Bridger Power Plant to reduce path transfers and protect bulk transmission lines and apparatus. Due to the magnitude of the generation loss, recovery from this disturbance can be extremely difficult. After the addition of B2H, this enormous amount of generation shedding will no longer be required.

Q. If a transmission line connecting PACE and PACW already exists, is B2H proposed merely as redundancy for that line?

A. No. As I stated above, in addition to the extremely important redundancy benefits, B2H will also provide the Company additional transmission capacity to serve customers. The Project will provide the Company 300 MW of additional west-to-east capacity and 600 MW of east-to-west capacity.[4] Additionally, the original permit funding agreement

[4] 2021 IRP at 89.

between B2H stakeholders left 400 MW of east-to-west capacity unassigned. The Company and IPC have agreed to divide this unassigned capacity consistent with each company's respective ownership share of B2H. As discussed above, the Company will own 54.55 percent of B2H. As a result, the Company will obtain 218 MW of the unallocated east-to-west capacity. This increases the Company's total east-to-west capacity in B2H to 818 MW.

Q. Are there any other reasons that B2H is necessary?

A. Yes. In addition to the benefits the Company and its customers will receive, B2H will enhance regional reliability by improving the Western transmission grid. NorthernGrid—a planning association aiming to facilitate regional transmission planning across the Pacific Northwest and Intermountain West—has repeatedly identified B2H as a regionally significant project in its biennial regional transmission plans.[5] From a regional perspective, the Project resolves possible system issues as identified in the NorthernGrid 2021 draft regional plan.

Relatedly, the Company is participating in the ongoing effort to evaluate and develop a regional resource adequacy program with other utilities that are members of the Northwest Power Pool. B2H is anticipated to provide incremental transmission infrastructure that will broaden access to a more diverse resource base, which will provide opportunities to reduce the cost of maintaining adequate resource supplies in the region.

[5] *See* NORTHERNGRID, *Regional Transmission Plan for the 2020-2021 NorthernGrid Planning Cycle* at 31 (Dec. 8, 2021) (available at https://www.northerngrid.net/private-media/documents/2020-2021_Regional_Transmission_Plan.pdf) (last visited Jan. 25, 2023).

V. BENEFITS OF B2H

Q. Is B2H a reasonable means of addressing the needs you discussed above?

A. Yes. As explained by Mr. Link in his testimony, B2H is the most cost-effective means of serving PacifiCorp's customers. In addition, B2H will provide several benefits to the Company's existing transmission system. These benefits include improved system reliability, redundancy between PACE and PACW, and improved economic dispatch of generation resources.

Q. Please summarize the benefits of a robust transmission system.

A. PacifiCorp's bulk transmission network is designed to reliably transport electric energy from a broad array of generation resources to load centers. There are many benefits associated with a robust transmission network, including:

- Reliable delivery of a diverse energy supply to continuously changing customer demands under a wide variety of system operating conditions;
- Access to some of the nation's best wind and solar resources, which provides opportunities to develop geographically diverse low-cost renewable assets; and
- Protection against market disruptions where limited transmission can otherwise constrain energy supply.

Q. Please describe in more detail how B2H will improve overall system reliability.

A. The transmission grid can be affected in its entirety by what happens on an individual transmission line or path. A single outage on any individual line or line segment due to storm, fire, or other interference can and does cause significant reductions in transmission capacity and can negatively impact the Company's ability to serve customers. Line outages require the Company to significantly curtail generation resources to stabilize system voltages and require less efficient re-dispatch of system resources to meet network load requirements.

In the event of a line outage, particularly an outage on the Hemingway–Summer Lake 500-kV line discussed above, the redundancy provided by B2H will allow the Company to continue to meet native load service obligations and continue to meet other contractual obligations to third parties. Strengthening this transmission and increasing system redundancy with B2H will benefit all customers by reducing the risk of outages and inefficient dispatch resulting from those outages.

In addition, B2H will improve the Company's ability to perform required maintenance without significant operational impacts to the system and will reduce impacts to customers during planned and forced system outages. Transmission line and substation maintenance windows are currently limited because the system is highly used. By relieving congestion and providing additional transmission paths, B2H will allow greater flexibility for the Company.

Moreover, as discussed in a recent paper from Grid Strategies titled "Transmission Makes the Power System Resilient to Extreme Weather," transmission lines can provide extraordinary benefits to regions experiencing extreme weather.[6] During Winter Storm Uri alone, the paper identifies seven different transmission connections that each could have provided over $80 million of benefits per 1,000 MW of transmission capacity for that single event, with one specific connection that would have provided nearly $1 billion in benefits per 1,000 MW.[7] Extreme events, such as

[6] Michael Goggin, GRID STRATEGIES, LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (July 2021) (available at https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf) (last visited Jan. 25, 2023).
[7] *Id.* at 11.

the 2021 Pacific Northwest heat dome, are increasing in frequency, and transmission lines provide a significant regional diversity, reliability, and resilience benefit.

Finally, through the asset exchanges discussed below, the Company will achieve additional capacity to southeast Idaho by receiving from IPC a percentage of the assets that make up the existing 500-kV and 345-kV transmission lines between the Borah, Kinport, Adelaide, Midpoint and Hemingway substations.

Q. Please describe the reliability benefits specific to B2H.

A. Construction of B2H will provide a parallel transmission path from southwest Idaho to the Pacific Northwest connecting generation resources to be transferred to PacifiCorp customers throughout the Company's service area. If one path is out of service, the other path will provide backup transmission service capability, within the limits of the remaining path. This is particularly important in the case of B2H, because currently the Hemingway–Summer Lake 500-kV line is the only 500-kV transmission path connecting Idaho and the Pacific Northwest. Adding a parallel path will improve system reliability by reducing the number and magnitude of transmission schedule reductions during line outage conditions.

Q. Please describe how B2H can provide cost savings in the form of reduced energy and capacity losses.

A. Reduced energy and capacity losses on the transmission system have the potential to provide significant cost savings over time. Generally, the addition of a new transmission path in parallel with existing lines, like B2H, will reduce the energy and capacity losses by reducing the impedance of the transmission system. Reduced line losses mean more efficient delivery of energy and capacity at reduced costs.

Additionally, B2H will reduce electrical losses. Losses on the power system are caused by electrical current flowing through energized conductors, which in turn creates heat. By constructing B2H, the Company may relieve less efficient, lower voltage transmission lines with very large transfers, which will reduce the electrical current through these lines and dramatically reduce the losses due to heat.

Q. Has B2H been recognized as providing reliability benefits to the broader Western Interconnection?

A. Yes. B2H has undergone an extensive process to be formally included in Western Electricity Coordinating Council ("WECC") path rating studies, which was a critical milestone for the projects, and one that can only occur if a new transmission facility can, at a minimum, reliably operate at its approved rating without negatively impacting other neighboring systems. B2H is not only considered minimally reliable, but regarded as an important transmission project that is necessary to support the long-term transmission expansion planning established in the Western Interconnection plans and in the most recent NorthernGrid regional transmission plan.[8]

Q. What is involved in the WECC path rating study process?

A. The WECC path rating studies follow a three-phase process established by the Planning Coordination Committee, the predecessor to the existing Reliability Assessment Committee, which uses peer review study groups, made up of the project sponsor and other interested WECC members, to establish a path rating for a given transmission path or set of transmission paths, which may exhibit simultaneous interactions with each other. Path rating studies use a transmission model of the Western Interconnection

[8] *Regional Transmission Plan for the 2020-2021 NorthernGrid Planning Cycle* at 31.

and will take multiple months to evaluate the performance of the new transmission facilities and to demonstrate that the proposed transmission project will have no negative impacts on previously established transmission path ratings. The path ratings that are established following this process represent the "Maximum Path Transfer Capability" of a transmission path.

Once projects complete the second phase of the path rating studies, they are granted an "Accepted" rating and placed in Phase 3 (construction phase) status. After the Accepted status is granted, other projects currently going through the WECC path rating process must recognize the project in their studies and cannot negatively impact the path rating for the project.

Q. Please describe the WECC path rating study process for B2H.

A. As project manager for B2H, IPC led B2H through the WECC path rating study process. Early in the B2H project development, IPC coordinated with other utilities in the Western Interconnection via the WECC Path Rating Process. IPC worked with other western utilities to determine the maximum rating (power flow limit) across the transmission line under various stresses, and system flow conditions on the bulk power system. Based on industry standards to test reliability and resilience, IPC simulated various outages, including the outage of B2H, while modeling these various stresses to ensure the power grid was capable of reliably operating with increased power flow. Through this process, IPC also ensured the B2H project did not negatively impact the ratings of other transmission projects in the Western Interconnection. IPC completed the WECC Path Rating Process in November 2012 and achieved a WECC Accepted Rating of 1,050 MW in the west-to-east direction and 1,000 MW in the east-to-west direction. It was determined that the B2H project would add significant reliability, resilience, and flexibility to the Northwest power grid.

VI. ASSET EXCHANGES

Q. Will there be additional modifications to the Company's transmission system relating to B2H?

A. Yes. In addition to the transmission capacity added through the construction of B2H, the Company's transmission system will be modified due to agreed upon asset exchanges with IPC.

Q. What are these asset exchanges?

A. IPC has agreed to transfer to the Company a percentage of the assets that make up the existing 500-kV and 345-kV transmission lines between the Borah, Kinport, Adelaide, Midpoint and Hemingway substations.[9] Similarly, as defined in the JPSA, the Company has agreed to transfer to IPC a percentage of the assets that make up the existing 345-kV transmission lines connecting the Populus substation to the Four Corners substation.[10] Finally, the Company has agreed to transfer to IPC certain Goshen area transmission assets, which would allow IPC to provide transmission service to all BPA customers in southeast Idaho currently served by the Company.[11]

Q. Has the Company executed agreements for these asset exchanges?

A. No, the Company is finalizing the terms of the agreement with IPC that will memorialize this asset exchange, which is referred to as the Joint Purchase and Sale

[9] Term Sheet at 13-14.
[10] *Id.* at 13.
[11] *Id.* at 14.

Agreement ("JPSA"). The parties anticipate finalizing and executing this agreement in March 2023.

Q. Is the Company requesting approval of these asset exchanges in this case?

A. No. The asset exchanges will not take effect until energization of the B2H Project which is expected to occur in 2026. The Company does not request approval of these asset exchanges at this time. The Company plans on seeking all necessary regulatory approvals relating to the disposition of property once the agreements are finalized.

Q. Please summarize the asset exchanges between Borah/Kinport, Hemingway, Midpoint, and Borah/Kinport.

A. The transfer by IPC to the Company of Borah/Midpoint West assets will provide ownership to PacifiCorp on the Company's existing transmission system from Borah/Kinport to Hemingway (east-to-west) and from Midpoint 500 to Borah/Kinport (west-to-east), including 500-kV and 345-kV transmission lines creating a path between the Borah, Kinport, Adelaide, Midpoint and Hemingway substations.

Q. Will the Company be responsible for upgrading those transmission facilities?

A. Upgrades will be required across the Borah West and Midpoint West paths to facilitate this portion of the proposed asset exchange. This includes the installation of a series capacitor bank on the Kinport-Midpoint 345-kV transmission line. However, IPC will be responsible for these upgrades under the to-be-executed Kinport Capacitor Bank Construction Agreement. I discuss this agreement in greater detail below.

Q. Please summarize the Populus to Four Corners asset exchanges.

A. The Company will assign to IPC ownership of a percentage of the assets that make up the existing PacifiCorp transmission system from Four Corners substation in New

Mexico to Populus substation in Idaho. This will include 345-kV transmission lines between the following substations and assets to create a path through each substation: Four Corners, Pinto, Huntington, Camp Williams, Mona, Terminal, 90th South, Ben Lomond and Populus.[12]

Q. Will the Populus to Four Corners asset exchange require upgrades?

A. The Company has not yet determined whether upgrades will be necessary. Consistent with federal processes, the Company and IPC will complete required studies to determine whether recent system upgrades result in a possible increase in existing transmission capacity between Borah and Populus to facilitate IPC's incremental transfer needs associated with this exchange. If determined necessary, the parties will identify revisions to existing agreements, upgrades, modifications, or other options to meet each party's commercial needs between Borah and Populus.

Q. Please summarize the Goshen area asset exchange.

A. The Company will transfer to IPC certain Goshen area transmission assets that will allow IPC to provide transmission service to all BPA customers in southeast Idaho currently served by the Company. The Company and IPC will make best efforts to allow IPC to serve these customers with only one leg of firm IPC network transmission service.[13]

Q. Will the Company implement an agreement for the Goshen area asset exchange?

A. The Goshen area assets to be exchanged are part of the JPSA discussed above that is being finalized for execution in March 2023.

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[12] *Id.* at 13.
[13] *Id.* at 15.

VII. AGREEMENTS RELATING TO B2H

Q. Do agreements relating to B2H remain outstanding?

A. Yes. The Term Sheet identifies the remaining agreements between the Company, IPC, and BPA. In my testimony, I will discuss eight of these agreements. Four additional agreements are discussed in Mr. Link's testimony.

Q. Which agreements will you be discussing in your testimony?

A. I will discuss the Second Amended and Restated B2H Joint Permit Funding Agreement; the JPSA; the Second Amended and Restated Joint Ownership and Operating Agreement ("JOOA"); the B2H Joint Construction Funding Agreement; the Longhorn Substation Funding Agreement; the Midpoint 500/345-kV Transformer Project Construction Agreement ("Midpoint Transformer Construction Agreement"); the Kinport – Midpoint 345-kV Series Capacitor Bank Project Construction Agreement ("Kinport Capacitor Bank Construction Agreement"); and the Coordination Agreement for the Meridian Series Capacitor Bank Project.

Q. Are there any agreements relating to B2H that neither you nor Mr. Link address in your testimonies?

A. Yes. Neither Mr. Link nor I discuss the agreements to which only BPA and IPC are parties. These agreements include: Network Integration Transmission Service Agreement ("NITSA") for Goshen Load; NITSA for Idaho Falls Load; and the Purchase, Sale, and Security Agreement.

Q. Please summarize the Second Amended and Restated B2H Joint Permit Funding Agreement.

A. The Second Amended and Restated Joint Permit Funding Agreement provides definitive terms and conditions by which the Company, IPC, and BPA will jointly support and contribute funds to the processes associated with obtaining necessary governmental authorizations and completing other necessary work to permit, site, and acquire rights-of-way for B2H.

The parties executed the initial Joint Permit Funding Agreement on January 12, 2012. The second amendment recognizes the reallocation of the parties' permitting interest and related funding obligations following the transfer of BPA's permitting interest to IPC. As discussed above, IPC's interest will increase because IPC will assume the ownership interest that had previously been assigned to BPA. Upon execution, IPC's permitting interest will increase to 45.45 percent and PacifiCorp's permitting interest will remain at 54.55 percent.

Q. When does the Company expect to execute the Second Amended and Restated B2H Joint Permit Funding Agreement?

A. Because BPA is a party to the Second Amended and Restated B2H Joint Permit Funding Agreement, the agreement must be submitted through BPA's public notice process. BPA's public process typically concludes within three months of BPA's provision of notice to the region, and the public process for B2H is expected to be complete by March 2023, and the parties will execute the agreement shortly thereafter.

Q. Has BPA begun the public process for their proposed new role in the B2H project?

A. Yes. On January 9, 2023, BPA released its Letter to the Region via their Tech Forum platform to customers and stakeholders announcing their completion of B2H project negotiations and releasing the customer engagement schedule, identifying dates for the comment period, customer workshop, and an expected final decision in March 2023.

Q. Please summarize the JPSA.

A. The JPSA implements the asset exchanges discussed above. The Company and IPC desired to exchange undivided ownership interests in certain transmission assets to provide transmission capacity that better aligns with the current configuration of the parties' respective future needs following the addition of B2H. The JPSA facilitates these asset exchanges and is contingent upon regulatory approvals for both parties.

Q. Which sale provisions are governed by the JPSA?

A. Under the proposed JPSA:

1. The Company will convey to IPC an ownership interest in identified Four Corners/Populus assets;
2. The Company will convey to IPC an ownership interest in identified Goshen area assets,
3. IPC will convey to the Company an ownership interest in identified Borah/Midpoint West assets, and
4. The purchase price of the assets being conveyed will be equal to the conveying party's net book value.

Q. When does the Company expect to execute the JPSA?

A. Although BPA is not a party to the JPSA, the JPSA reflects BPA's decision to remove its ownership interest of B2H. For that reason, the Company and IPC expect to execute the JPSA following the completion of BPA's notice proceedings in March 2023.

Q. Please summarize the Second Amended and Restated JOOA.

A. The Company and IPC will expand the existing JOOA, as amended and restated August 22, 2019, to include ownership, operation and maintenance provisions associated with the B2H project. In addition, the Second Amended and Restated JOOA will include:

1. Operation and maintenance provisions associated with the assets acquired by both parties under the JPSA;
2. The transfer of ownership by IPC to the Company for 300 MW of west-to-east transmission assets between Midpoint and Borah;
3. The transfer of ownership by IPC to the Company for an additional 600 MW of east-to-west transmission assets between Borah and Hemingway; and
4. The transfer of ownership by the Company of 200 MW of bi-directional transmission assets between Populus, Mona and Four Corners.

Q. What will be the expected effective date of the Second Amended and Restated JOOA?

A. The Company and IPC expect the Second Amended and Restated JOOA to take effect upon energization of B2H.

Q. Please summarize the B2H Joint Construction Funding Agreement.

A. This agreement will provide definitive terms and conditions by which IPC and the Company will jointly support and contribute funds for the procurement, construction, and commissioning of B2H to allow for energization of the project by the earliest in-service date needed by the parties. In addition, it appoints IPC as the construction project manager for development and construction of the B2H project.

Q. Which B2H stakeholders are parties to the B2H Joint Construction Funding Agreement?

A. The Company and IPC will execute the B2H Joint Construction Funding Agreement.

Q. Has the scope of the B2H Joint Construction Funding Agreement expanded?

A. Yes. The Midline Series Capacitor Project Funding Agreement identified in § 3(a)(12) of the Term Sheet was initially identified as a separate agreement but construction of the Midline Series Capacity was subsequently incorporated into the overall construction plan for B2H. The work will include installation of the Midline Series Capacitor substation, which is necessary to reduce simultaneous interactions between the NW AC Intertie, central and southern Oregon load service, and Path 14 (Idaho to Northwest).

Q. What will be the expected execution date of the B2H Joint Construction Funding Agreement?

A. The Company and IPC expect to execute this agreement in July 2023, prior to construction of B2H.

Q. Please summarize the Longhorn Substation Funding Agreement.

A. The Longhorn Substation Funding Agreement is an agreement between the Company, IPC, and BPA detailing the conditions for construction of the proposed Longhorn substation, which is the expected western terminal of B2H. The substation will be constructed on land currently owned by BPA.

Provisions will include:

1. A use-of-facilities charge or other charge pursuant to BPA's OATT to be paid by IPC and the Company to allow the parties to transact across the Longhorn bus in the future; and
2. Ownership, operation, and maintenance of B2H equipment by IPC and the Company, including:
   a. A B2H project-related series capacitor at the Longhorn substation;
   b. The B2H project shunt line reactors at Longhorn; and
   c. Any ancillary equipment required to support the B2H project series capacitor and shunt line reactors.

The agreement will be contingent upon BPA completing its obligations and responsibilities under various environmental compliance laws.

Q. Please summarize the Midpoint Transformer Construction Agreement.

A. The Midpoint Transformer Construction Agreement is an agreement between IPC and the Company detailing the terms for upgrading the Midpoint transmission assets. As discussed above, IPC will transfer to the Company a percentage of the assets that make up the existing Midpoint transmission lines. Under the Midpoint Transformer Construction Agreement, IPC will make capital upgrades to the Midpoint 500-kV and

345-kV transmission substations, including a second 500/345-kV transformer bank and 345-kV tie line. The parties will jointly own the assets in accordance with the JPSA and the Second Amended and Restated JOOA.

Q. Please summarize the Kinport Capacitor Bank Construction Agreement.

A. The Kinport Capacitor Bank Construction Agreement will be a contract between the Company and IPC detailing improvements to the Kinport transmission assets. As discussed above, IPC will transfer these assets to the Company. Under the Kinport Capacitor Bank Construction Agreement, IPC will make capital upgrades to the Midpoint 345-kV transmission line, by installing the Kinport-Midpoint 345-kV Series Capacitor Bank. The parties will jointly own the assets in accordance with the JPSA and the Second Amended and Restated JOOA.

Q. Please summarize the Coordination Agreement for the Meridian Series Capacitor Bank Project.

A. This is an agreement between the Company and BPA. The Company and BPA will draft a coordination agreement that sets forth the agreed process for the Company's intended upgrade, upon BPA notice, of the existing Meridian series capacitor banks on the Company's segment of the Dixonville-Meridian-Klamath Falls-Captain Jack lines in southern Oregon, as detailed in March 2021 report titled "Phase II Joint Study Report (2020-2021), Boardman to Hemingway (B2H) and Incremental Central Oregon Load."

VIII. ADVANCED REVIEW PROCESS REQUIREMENTS

Q. Are you familiar with the Advanced Review Process for certain transmission assets in Wyoming?

A. Yes, I am.

Q. What does the Advanced Review Process require?

A. Under the Advanced Review Process, the Company agreed to ask the Commission to "rule on whether the proposed construction of the transmission line is reasonable and in the public interest in advance of the line being constructed."[14] The Company also agreed to provide certain additional information in support of its CPCN application, including a "detailed analysis and quantification of the benefits of the facilities to both the overall PacifiCorp system and to Wyoming customers in particular in terms of increased reliability or relatively lower net power costs, increased generation alternatives and the benefits of generation diversity."[15]

Q. Is B2H reasonable and in the public interest?

A. Yes. For the reasons discussed above, B2H is necessary to enable the Company to efficiently deploy new generating facilities and better utilize existing resources to meet projected resource needs. The Project is a reasonable means of meeting these needs because, as Mr. Link explains in his testimony, B2H is the most cost-effective means of serving the Company's customers.

Q. Is there specific information that the Company must provide for purposes of the Advanced Review Process?

A. Yes. The Advanced Review Process includes specific information requirements. These requirements include: a description of the proposed facility; an estimated cost to construct the facility; a discussion of the impact on access to renewable generation resources; the proposed cost allocation between federal and state jurisdictions (i.e., the amount of revenue that will be received from third-party transmission customers taking

[14] 2010 Wyoming GRC Stipulation at ¶13(a)(ii).
[15] *Id.* at ¶13(a)(iii)(3).

service under the Company's OATT); and a discussion of any sage grouse habitat in the vicinity of the Project.

I have already discussed several of these requirements in my testimony. In Section III, I provided a description of the Project. Additionally, as I discussed above, the Company estimates that its in-service cost of B2H will be [redacted], including AFUDC. Finally, as I explained above, B2H will be considered a network transmission asset under the Company's OATT and a portion of Project costs will be incorporated into the Company's transmission rates, which will be recovered from third-party transmission customers and included as an offset to the benefit of retail customers. Mr. Link's testimony explains that the expected revenues from third-party transmission customers will account for roughly 20 percent of the project costs.

Q. Please describe the impact on access to renewable generation resources.

A. B2H will connect PACE and the Mid-Columbia ("MidC") trading hub. This connection with the Mid-C markets will provide the Company greater access to diverse hydro, wind, and solar resources located in the Pacific Northwest.

Q. Please summarize the sage grouse habitat located within the vicinity of the Project.

A. Much of the sage grouse habitat located in the vicinity of the Project is in Oregon. It is my understanding that to obtain a site certificate from Oregon EFSC, IPC was required to demonstrate compliance with Oregon's Greater Sage-Grouse Conservation Strategy, which sets population and habitat management objectives and advances sage-grouse population and habitat protection through a mitigation hierarchy and the establishment of a mitigation standard for impacts from certain types of development actions in sage-grouse habitat. Oregon EFSC determined that IPC has demonstrated compliance with the Greater Sage-Grouse Conservation Strategy by minimizing impacts to sage grouse habitat to the extent possible and mitigating unavoidable impacts. The site certificate for B2H further includes multiple conditions ensuring protection of sage grouse habitat.[16]

IX. RECOMMENDATION AND CONCLUSION

Q. Please summarize your recommendation to the Commission.

A. I recommend that the Commission grant the Company's waiver request or, alternatively, approve its Application. B2H will provide substantial benefits to its customers and the construction of B2H is necessary, reasonable, and in the public interest. I recommend that the Commission grant the Company a non-situs CPCN and issue Advance Review approval no later than June 30, 2023, to ensure IPC may begin timely construction of B2H in time to complete the Project by the expected 2026 in-service date.

Q. Does this conclude your direct testimony?

A. Yes.

[16] *In re Application for Site Certificate for the Boardman to Hemingway Transmission Line*, Final Order, Attachment 1: Site Certificate at 53-55, 60, 65 (Sept. 27, 2022) (available at https://www.oregon.gov/energy/facilities-safety/facilities/Facilities%20library/2022-09-27-Attachment-1-Site-Certificate.pdf) (last visited Jan. 4, 2023).

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A WAIVER OF THE NON-SITUS CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR GATEWAY SEGMENT H, THE BOARDMAN TO HEMINGWAY TRANSMISSION PROJECT	)	DOCKET NO. 20000-___-EN-23 (RECORD NO. ______)

AFFIDAVIT, OATH AND VERIFICATION

Rick A Vail (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is the Vice President of Transmission for PacifiCorp, which is a party in this matter.

Affiant prepared and caused to be filed direct testimony in this proceeding. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant's knowledge, all statements and information contained within the testimony and all of its associated attachments are true and complete and constitute the recommendations of the Affiant in his official capacity as Vice President, Transmission.

Further Affiant Sayeth Not.

Dated this 2nd day of February, 2023

Rick A. Vail
825 NE Multnomah
Portland, OR

STATE OF OREGON)
) SS:
COUNTY OF MULTNOMAH)

The foregoing was acknowledged before me by Rick A. Vail on this 2 day of FEBRUARY, 2023. Witness my hand and official seal.

Notary Public

My Commission Expires: 9/7/2026

OFFICIAL STAMP
SCOTT ASHLEY MEASE
NOTARY PUBLIC - OREGON
COMMISSION NO. 1028167
MY COMMISSION EXPIRES SEPTEMBER 7, 2026