Department of Energy

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

FREEDOM OF INFORMATION ACT/PRIVACY PROGRAM

March 13, 2024

In reply refer to: FOIA #BPA-2022-00999-F

SENT VIA EMAIL ONLY TO: sbatman@cosgravelaw.com

Shellice Batman
Cosgrave Vergeer Kester LLP
900 SW 5th Avenue, 24th Floor
Portland, Oregon 97204

Dear Ms. Batman,

This communication is the Bonneville Power Administration's (BPA) third partial response to your request for agency records made under the Freedom of Information Act, 5 U.S.C. § 552 ("FOIA"). Your FOIA request was received on June 28, 2022, and formally acknowledged on July 14, 2022. A first partial response to your request was sent to you on March 21, 2023, and a second partial response was sent to you on July 27, 2023.

Original Request
"Any and all documents regarding the Holiday Farm Fire that began on September 7, 2020, in Lane County, Oregon - including but not limited to Investigation documents and reports, photographs, video recording, audio recordings, and correspondence regarding the fire and its causes."

Clarification
On July 1, 2022, you communicated with the agency via phone and discussed the scope of your request. Specifically discussed were the implications of requesting, "any and all documents". FOIA office staff explained that, (1) the agency's FOIA staff is small, (2) requests are processed on a first-in, first-out basis, (3) the agency's search for a wide records scope would take a significant amount of time and resources, and (4) your FOIA request could therefore take between two and three years to process. As discussed, BPA received a similar FOIA request which also seeks a voluminous number of records related to the Holiday Farm Fire ("HFF"). The agency worked with that FOIA requester to narrow the scope of their request to focus on the HFF records of most interest to them. A summary of the results of the agency's agreement with the prior FOIA requester to re-scope their FOIA request was shared with you. You and the agency agreed that BPA would process the similarly responsive records coincidentally with the similar FOIA request response. On July 12, 2022, you replied to BPA via email and, (1) agreed to re-scope your request to that which was suggested to you on July 1, and (2) asked for additional records to be collected for your HFF request. Your re-scoped FOIA request follows.

Re-scoped Request

Section 1

1. All documents and communications concerning any faults or outages, from September 6th–8th, 2020,on BPA's transmission system or related facilities along the McKenzie River Highway (Highway 126, between Eugene and Rainbow, Oregon) or interconnected to the Cougar Dam. "Transmission system" is defined as power lines, substations, and microwave sites which support the communications network.
2. All documents and communications concerning any faults or outages, from September 6th–8th, 2020, on third party transmission systems or related facilities interconnected to BPA's transmission system along the McKenzie River Highway or interconnected to the Cougar Dam.
3. All documents and communications related to any incident reports concerning BPA's transmission system or related facilities along the McKenzie River Highway or interconnected to the Cougar Dam. Scope/Date range = Sep 6, 2020 – October 31, 2020.
4. All documents and communications related to any incident reports concerning third party transmission systems or related facilities interconnected to BPA's transmission system along the McKenzie River Highway or interconnected to the Cougar Dam. Scope/Date range = Sep 6, 2020 – October 31, 2020.
5. All documents and reports concerning any inspection of BPA's transmission system or related facilities along the McKenzie River Highway or interconnected to the Cougar Dam occurring after September 7, 2020. Scope/Date range = Sep 6, 2002 – October 31, 2020.
6. All documents, communications, and any underlying data relied upon in the creation of the document entitled: "Holiday Farm Fire Outage Sequence of Events."
7. All documents and communications related to investigations of the Holiday Farm Fire that were provide[d] to the US Forest Service fire investigator.

Section 2

1. A map or diagram of BPA's power distribution system in Oregon.
2. A map or diagram of how and where [Lane Electric Cooperative] LEC is connected to the BPA power grid.
3. Documents evidencing or relating to ownership of the transmission lines and related equipment from Trailbridge/Carman Smith Powerhouses to the Thurston Substation.
4. All agreements in place on September 7, 2020 between the BPA and [the Eugene Water and Electric Board] EWEB relating to the transmission, distribution or purchase of electricity.
5. All agreements in place on September 7, 2020 between the BPA and LEC relating to the transmission, distribution or purchase of electricity.
6. All agreements in place on September 7, 2020 between the BPA and the Army Corp of Engineers relating to the transmission, distribution or purchase of electricity generated by the Cougar Powerhouse.

7. Documents containing the name and affiliation of any individual who provided information incorporated into the document entitled "Holiday Farm Fire Outage Sequence of Events." or are referenced in the "Comments" sections of that document.

Third Partial Response
BPA continues to process your FOIA request. To both accommodate the review of the large volume of responsive records, and to provide the records expediently, within the limitations of available agency resources, BPA is releasing responsive records to you in installments. Partial records releases are permitted by the FOIA. This third partial response concerns section 2 of your request:

- **Item 1** – A map of BPA's power distribution system in Oregon is publicly available on the agency website at: bpa-transmissionlines-and-facilities.pdf

- **Item 2 –** One page was collected, the record titled "Land Electric Cooperative Transmission System Diagram."

- **Item 3** – Eight pages of responsive records were collected.

- **Item 4** – 459 pages of responsive records were collected.

- **Item 5** – 197 pages of responsive records were collected and are being withheld in full under 5 U.S.C. § 552(b)(4) (Exemption 4). See the section titled 'Explanation of Exemptions.'

- **Item 6** – 206 pages of responsive records were collected. 195 pages are released in full, contracts titled 08TX-13663 and 14-03-19250. Eleven pages are being withheld in full; these are detailed below in the section titled 'Critical Energy/Electric Infrastructure Information.'

- **Item 7 –** The author of the "Holiday Farm Fire Outage Sequence of Events," BPA Substation Operator Christopher Meloy, explained that the data for this report came from automatically-recorded sources, not individual persons. The author also provided clarification for all instances where the word "Comments" appears:

    - **Page 1** – A screenshot of the dispatching log. There are no documents that contain the names of individuals mentioned here.
    - **Page 2** – A condensed table showing loading changes. The author added these comments to provide context for non-technical readers.
    - **Page 2** – A screenshot of the dispatching log. There are no documents that contain the names of individuals mentioned here.
    - **Page 2** – A condensed table showing loading changes. The author comments to provide context for non-technical readers.

- **Pages 3 to 4** – A digital events table. The author added comments in plain text to explain the data.

The 663 pages described above accompany this communication with fifteen redactions applied under 5 U.S.C. § 552(b)(6) (Exemption 6). A more detailed explanation of the applied exemptions follows.

Explanation of Exemptions
The FOIA generally requires the release of all agency records upon request. However, the FOIA permits or requires withholding certain limited information that falls under one or more of nine statutory exemptions (5 U.S.C. §§ 552(b)(1-9)). Further, section (b) of the FOIA, which contains the FOIA's nine statutory exemptions, also directs agencies to publicly release any reasonably segregable, non-exempt information that is contained in those records.

Exemption 4
Exemption 4 protects "trade secrets and commercial or financial information obtained from a person [that is] privileged or confidential." (5 U.S.C. § 552(b)(4)). Information is considered commercial or financial in nature if it relates to business or trade. Information is considered confidential if it is customarily kept private or closely held by the submitter, *and* the information was provided under an express or implied assurance of confidentiality by the receiving agency. This exemption is intended to protect the interests of both the agency and third-party submitters of information.

Prior to publicly releasing agency records, BPA was required by Exemption 4 to solicit objections to the public release of any third-party confidential commercial information contained in the responsive records set. BPA provided each submitter with an opportunity to formally object to the public release of their information contained in BPA records. The Lane Electric Cooperative (LEC) submitted objections to BPA. BPA accepted those objections, based on guidance available from the U.S. Department of Justice, finding that the material is both commercial and confidential. Therefore, BPA is withholding LEC's commercial confidential information from public release. The FOIA does not permit a discretionary release of information otherwise protected by Exemption 4.

Exemption 6
Exemption 6 serves to protect Personally Identifiable Information (PII) contained in agency records when no overriding public interest in the information exists. BPA does not find an an overriding public interest in a release of the information redacted under Exemption 6—specifically, individuals' signatures. This information sheds no light on the executive functions of the agency and BPA finds no overriding public interest in its release. BPA cannot waive these redactions, as the protections afforded by Exemption 6 belong to individuals and not to the agency.

Lastly, as required by 5 U.S.C. § 552(a)(8)(A), information has been withheld only in instances where (1) disclosure is prohibited by statute, or (2) BPA foresees that disclosure would harm an interest protected by the exemption cited for the record. When full disclosure of a record is not possible, the FOIA statute further requires that BPA take reasonable steps to segregate and release nonexempt information. The agency has determined that in certain instances partial disclosure is possible and has accordingly segregated the records into exempt and non-exempt portions.

Critical Energy/Electric Infrastructure Information
BPA currently believes that eleven pages of records responsive to your request item six contain Critical Energy/Electric Infrastructure Information (CEII). CEII is defined by the Federal Energy Regulatory Commission (FERC) as information related to critical electric infrastructure, or proposed critical electrical infrastructure, generated by or provided to FERC, or to other Federal agencies, which is designated as CEII by FERC, or by the Secretary of the U.S. Department of Energy ("DOE"), pursuant to section 215A(d) of the Federal Power Act.

Specifically, CEII is engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that: relates details about the production, generation, transmission, or distribution of energy; could be useful to a person planning an attack on critical infrastructure; is exempt from mandatory disclosure under the FOIA; and gives strategic information beyond the location of the critical infrastructure. Critical electric infrastructure means a system or asset of the bulk-power system, (physical or virtual) the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters.

The specific records at issue discuss critical resources. A review of these records will require additional consults and processing steps. Please let us know within thirty calendar days if you would like us to continue processing these records. If you do not respond, we will assume that you are not interested in these critical resource records and we will note that in the file.

Certification
Pursuant to 10 C.F.R. § 1004.7(b)(2), I am the individual responsible for the records search and information release described above. Your FOIA request BPA-2022-00999-F remains open, with available agency records still under process.

Appeal
Note that the records release certified above is partial. Additional records releases will be forthcoming as agency resources and records volumes permit. Pursuant to 10 C.F.R. § 1004.8, you may appeal the adequacy of the records search, and the completeness of this partial records release, within 90 calendar days from the date of this communication. Appeals should be addressed to:

Director, Office of Hearings and Appeals

HG-1, L'Enfant Plaza
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585-1615

The written appeal, including the envelope, must clearly indicate that a FOIA appeal is being made. You may also submit your appeal by e-mail to OHA.filings@hq.doe.gov, including the phrase "Freedom of Information Appeal" in the subject line. (The Office of Hearings and Appeals prefers to receive appeals by email.) The appeal must contain all the elements required by 10 C.F.R. § 1004.8, including a copy of the determination letter. Thereafter, judicial review will be available to you in the Federal District Court either (1) in the district where you reside, (2) where you have your principal place of business, (3) where DOE's records are situated, or (4) in the District of Columbia.

Additionally, you may contact the Office of Government Information Services (OGIS) at the National Archives and Records Administration to inquire about the FOIA mediation services they offer. The contact information for OGIS is as follows:

Office of Government Information Services
National Archives and Records Administration
8601 Adelphi Road-OGIS
College Park, Maryland 20740-6001
E-mail: ogis@nara.gov
Phone: 202-741-5770
Toll-free: 1-877-684-6448
Fax: 202-741-5769

Next Partial Release Target Date
As mentioned, BPA awaits your response regarding the records which contain CEII. Please let us know within thirty calendar days if you would like us to continue processing these records. If you do not respond, we will administratively close this request.

Questions about this communication or the status of your FOIA request may be directed to FOIA Program Lead Jason Taylor at jetaylor@bpa.gov.

Sincerely,

CANDICE PALEN
Digitally signed by CANDICE PALEN
Date: 2024.03.13 15:28:55 -07'00'

Candice D. Palen
Freedom of Information/Privacy Act Officer

EUGENE-ALDERWOOD NO.1 115-KV LINE
ALBANY-EUGENE NO.1 115-KV LINE
EUGENE (BPA)
115 KV
T-1324
15/20/25 MVA
34.5 KV
2144 IN RMS
2145 OUT
L116
L107
759
(BPA)
(LEC)
34.5 KV
WENDSON (BPA)
MAPLETON SUBSTATION (BPA)
B535
B534
7296
7295
WALTON SUBSTATION (BPA)
B601
B959
B971
789
(EPUD)
(BPA)
NOTI CREEK (EPUD)
20/26/33 MVA AUTO-TRANSFORMER
B972
B1401
B1403
B1408
7367
7390
LANE-WENDSON NO.1 115-KV LINE
LANE (BPA)
B1608
115 KV
B1402
12/16/20 MVA
12.5 KV
L1222
FERN RIDGE (LEC)
RMS
215 OUT
X-LINE FEEDER
VENETA FEEDER
FLECK ROAD FEEDER
N.C.
CROW FEEDER
N.O.
KING ESTATE PV SOLAR
500-kW
300-kW
3283 OUT
3284 IN
RMS
RAINBOW VALLEY (LEC)
BANK NO.2 12/16/20 MVA (OLD)
BANK NO.1 12/16/20 MVA (NEW)
673 OUT
4556 IN
RMS
4557 OUT
4558 IN
RMS
CROW ROAD FEEDER
GIMPL HILL FEEDER
TO SPENCER CREEK ROAD
PINE GROVE FEEDER
BERTELSEN (EWEB)
WILLOW CREEK (EWEB)
HAWKINS (EWEB)
FOX HOLLOW (LEC)
34.5 KV
AUTO XFER CNTL
4.2/5.25 MVA
12.5 KV
"AB"-LINE FOX HOLLOW
NORTH FDR.
SOUTH FDR.
"A"-LINE
B1480
7917
B1481
(BPA)
HIDEAWAY (LEC)
B1482
115 KV
15/20/25 MVA
12.5 KV
RMS
1936 OUT
CONNECTION POINT FOR MOBILE TRANSFORMER
FUTURE FEEDER
FUTURE FEEDER
TO CRESWELL
TO DILLARD ROAD
BLUE RIVER (LEC)
8.4/10.5 MVA
SPARE
6/7.5 MVA
L1352
RMS
716 OUT
4574 IN
B1450
BLUE RIVER SWITCHING STATION (LEC)
12.5 KV
WEST FEEDER (DOWN-RIVER)
EAST FEEDER (UP-RIVER)
115 KV 0.38-MI
TRAIL BRIDGE
CARMEN-SMITH (EWEB)
18.0-MI 666-ACSR
CARMEN SMITH - COUGAR TAP 115-KV LINE
EWEB
BPA
2.12-MI
666 ACSR
COUGAR (BPA)
COUGAR POWERHOUSE (USACE)
PCB-1396
TO CURRIN, WILLAKENZIE, & MCKENZIE SUBSTATIONS (EWEB)
TO MCKENZIE SUBSTATION (EWEB)
THURSTON (EWEB)
115-KV
PCB-2360
33.38-MI 666 ACSR
BPA COUGAR-THURSTON NO.1 115-KV LINE
0.86-MI 795 ACSR
B1449
B1460
ALVEY (BPA)
15/20/25 MVA
T-1654
L994
1173 OUT
4302 IN
RMS
(PAC)
(LEC)
TO MT VERNON SUBSTATION (SUB)
LOOKOUT POINT-ALVEY NO. 2 115-KV LINE (BPA)
LOOKOUT POINT-ALVEY NO.1 115-KV LINE (BPA)
B1064
B1063
7638
B1010
B1008
PLEASANT HILL SUBSTATION (EPUD)
LOOKOUT POINT (BPA)
LOOKOUT POINT POWERHOUSE (USACE)
48 MVA
13.8 KV
GOSHEN (PAC)
CRESWELL (EPUD)
DEXTER (LEC)
FALL CREEK (NORTH)
HWY 58 (EAST)
RATTLESNAKE (WEST)
SOUTH BANK (CLOVERDALE)
L56
10/12 MVA
RMS
848 OUT
4308 IN
B1051
B1009
7515
BUPPO G/S
13 MVA
DEXTER P.H. (USACE)
CLOVERDALE (LEC)
2.5 MVA
CLOVERDALE FEEDER
BEAR CREEK
B367
B369
B366
B308
B368
7134
6/7.5 MVA BANK #2
12/16/20 MVA BANK #1
RMS
972 OUT
OAKRIDGE (LEC)
(3) 1-PHASE VOLTAGE REGULATORS
WEST FIR
HWY. EAST
BALD KNOB
WILLW41
WILL CITY FDR
LYNX HOLLOW (LEC)
2.8/3.5 MVA
NORTH LYNX HOLLOW ROAD FEEDER
SOUTH COTTAGE GROVE FEEDER
ALVEY-COTTAGE GROVE NO. 1 115-KV LINE
ALVEY-MARTIN CREEK NO. 1 115-KV LINE
CULP CREEK (LEC)
5/5.7-MVA
UPRIVER FEEDER
DOWNRIVER FEEDER
HILLS CREEK (BPA)
36 MVA
HILLS CREEK POWERHOUSE (USACE)
VILLAGE GREEN (PAC)
12/20 MVA BANK 1
12/20 MVA BANK 2
2M17
2M18
N.O.
LANE ELECTRIC 34.5-KV SYSTEM BLOCK DIAGRAM
DORENA (BPA)
139 OUT
RMS
B1578
T-1171
8.4/10.5 MVA
L1414
L1413
CONNECTION POINT FOR MOBILE TRANSFORMER
DORENA (LEC)
L-201
5/6.2 MVA
MOSBY CREEK FEEDER
ROW RIVER FEEDER
MOSBY CREEK (LEC)
4.2/5.25 MVA
SOUTH FEEDER
NORTH FEEDER
DORENA TAP (PAC)
2M34
2M35
B1577
7826
MARTIN CREEK (BPA)
TO ALVEY SUBSTATION (BPA)
TO DRAIN (BPA)
MARTIN CREEK-DRAIN NO. 1 115-KV LINE
LATHAM (EPUD)
B1833
B1834
B1835
8195
COTTAGE GROVE-DRAIN NO. 1 115-KV LINE
LATHAM TAP (BPA)
DRAIN TAP (BPA)
COTTAGE GROVE SWITCH STATION SITE (PAC) (ABANDONED)
TO DIXONVILLE (PAC) [ABANDONED]
Ver. 1.16
UPDATE Ver. 1.16
LANE ELECTRIC COOPERATIVE TRANSMISSION SYSTEM DIAGRAM
SYSTEM ONE-LINE DIAGRAM
SHEET 1 OF 1
REVISED: 4/18/2022

AUTHENTICATED Contract No. 08TX-13663

MEMORANDUM OF AGREEMENT
for MAINTENANCE AND REPAIR of
GENERATING AND TRANSMISSION RELATED FACILITIES
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION

and the

UNITED STATES OF AMERICA
DEPARTMENT OF DEFENSE
acting by and through the
U.S. ARMY CORPS OF ENGINEERS
NORTHWEST DIVISION

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This MEMORANDUM OF AGREEMENT (Agreement) FOR MAINTENANCE AND REPAIR (M&R), is entered into by the BONNEVILLE POWER ADMINISTRATION (Bonneville), and the United States ARMY CORPS OF ENGINEERS, NORTHWEST DIVISION (Corps) (hereinafter collectively referred to as "Parties" and individually as "Party"), for the maintenance and repair (M&R)of the Corps' facilities by Bonneville.

WITNESSETH:

WHEREAS the Parties desire to enter into this Agreement providing procedures for the M&R of the Corps' hydro-electric power generating and transmission related facilities and payment for such services;

WHEREAS the Parties desire to enter into this Agreement under the Economy Act, 31 U.S.C. §1535, the Bonneville Project Act of 1937, 16 U.S.C. §832, and other federal law; and

WHEREAS the Parties desire to continue to cooperate with each other under other agreements and arrangements, and seek to further expand their collaboration under this Agreement;

NOW, THEREFORE, the Parties mutually agree as follows:

1. TERM OF AGREEMENT

This Agreement shall be effective at 0000 hours on **29 May 2009** (Effective Date). Any Party may terminate this Agreement upon 60 days' written notice to the other Party. All liabilities incurred under this Agreement are hereby preserved until satisfied.

2. M&R OF THE CORPS' FACILITIES BY BONNEVILLE

(a) **Initiating Work**

Bonneville, in coordination with the Corps' water management personnel, shall develop real-time outage scheduling based on proposed outage schedules at individual Corps' projects. Such real-time outage schedules shall incorporate biological opinion requirements that outline periods when certain types of outages are discouraged.

This Agreement requires the parties to coordinate and plan M&R work that Bonneville will perform at the Corps' facilities as follows:

When the Corps initially determines that they have an M&R request to submit to Bonneville, the Corps shall coordinate with Bonneville's Customer Service Engineer (CSE) for the Corps. The CSE shall coordinate with all Bonneville internal stakeholders to determine if and which Bonneville resources are available to do the work. Also the CSE will coordinate with all stakeholders (internal and external) for agreement on scope of work, costs, schedule, and contract review before contracts are signed.

When a request for M&R work under this agreement is in the process of being coordinated by Bonneville's CSE, the Corps' Project Operations Manager or designated representative requiring assistance from Bonneville will coordinate the technical requirements, delivery dates, transportation and shipping arrangements, types of spares and materials to be delivered, documentation, and schedule with the Bonneville crews and staff that will perform the M&R work. This will be done on a project-by-project basis and initiated by the Corps' Project Operations Manager or designated representative who is requesting Bonneville's assistance.

The initial request by the Corps to the CSE may be initiated verbally and then shall be collaboratively developed into a written Statement of Work (SOW) and Statement of Cost (SOC) which will become a part of the Military Interdepartmental Purchase Request (Government Order).

The Government Order shall include a Corps assigned Government Order number, the Bonneville assigned contract number, the Corps' "Facility Equipment and Maintenance (FEM) Job Number" under which the work is being performed, the Corps' Agency Location Code, and the Corps' accounting and appropriation data.

The following information will normally be included in the SOW:

(1) A statement describing "Why" the work needs to be performed by Bonneville;

(2) A statement describing "What" the work entails;

(3) A statement describing "Where" the work is to be performed;

(4) A statement describing "Who" or which Bonneville crew will perform the work;

(5) A statement setting out "How Much" the Corps will reimburse Bonneville for performing the work, or alternatively, a statement setting forth an estimate of the cost to perform the work in the form of a SOC, which would include an estimate of the labor, materials, equipment, rentals, etc. to accomplish the work called for under the SOW;

(6) A statement describing "When" the work will commence and be completed;

(7) A statement setting forth any "Optional Items" that could be performed under the SOW based on what is discovered during performance of the work;

(8) A statement describing any "Supplies or Transportation Services" to be provided under the project;

(9) A statement describing any "Close Out Documentation or Reports" required for the project.

The Corps' Project Operations Manager or designated representative requesting the work will develop the Government Order in accordance with Economy Act Order Procedures, attach the collaboratively developed SOW and SOC documentation, and submit the request to the CSE who will then process the Government Order through Bonneville's assigned Account Executive for the Corps for signature.

Bonneville shall respond in a timely fashion to reasonable written requests for M&R work submitted by the Corps' Project Operations Manager or designated representative. Bonneville shall use its best efforts to perform the requested M&R work provided that Bonneville, in its sole determination, has adequate resources available to perform the M&R work.

Upon Bonneville's receipt of a request from the Corps to perform M&R work, Bonneville will use its best efforts to schedule and perform M&R work that requires a transmission system outage at times consistent with the posted Bonneville Transmission Outage Schedule. Bonneville shall comply with applicable regional OASIS and related posting guidelines for all outages. Bonneville has the right, at its discretion, to reschedule M&R work. In that event, the Parties will agree upon a new date for Bonneville to perform the M&R work.

Bonneville's District Operations and Maintenance Manager or designated representative shall verbally provide at least five working days notice to the Corps' Project Operations Manager or designated representative, prior to the date on which Bonneville personnel will be on site at a particular project to perform M&R work under the terms of this Agreement.

The schedule (included in the SOW) for the commencement of M&R work shall be coordinated with and approved by the Corps Project Operations Manager or Corps designee prior to the arrival of the Bonneville crew on site.

(b) **Establishment of Accounting Mechanism and Invoicing**
The Corps will provide Bonneville a Government Order before the work commences except in emergency situations, as set out in Section 3 of this Agreement. Bonneville will provide an invoice for M&R work within 90 days of completion of the project and accounting for the project will be closed. Bonneville will initiate billings via the Intra-governmental Payment and Collection (IPAC) system as discussed in Section 4 below.

(c) **Replacement Parts**
Except as otherwise agreed to in writing by the Parties, the Corps shall:

(1) Provide all replacement parts and equipment to Bonneville at the Corps' expense; or

(2) Reimburse Bonneville for parts and equipment Bonneville may provide.

(d) **Capital Improvements**
This Agreement is intended to cover planned and emergency M&R work at the Corps' existing facilities, not capital improvements or construction of new facilities. Capital improvements or upgrades to the Corps' facilities shall be performed and governed by separate agreements between the Parties. Whether a particular repair constitutes a capital improvement depends upon the circumstances, and the Parties will mutually determine what constitutes a capital improvement on a case-by-case basis.

(e) **Manner of Maintenance**
Bonneville shall perform M&R work on the Corps' facilities under this Agreement in the manner and to the quality agreed to in writing by the Parties. In the absence of such an agreement, Bonneville shall perform M&R work on the Corps' facilities in the same manner and to the same quality as Bonneville maintains and repairs Bonneville facilities.

(f) **Security and Safety Practices and Procedures**
Bonneville shall perform all M&R work consistent with both Parties' safety standards and practices, and the security procedures established by the Corps' Project Operations Manager at each project. In the event of a conflict between the safety practices, the more stringent practices shall apply. In the event of a dispute over safety practices, the matter will be referred for resolution to the Corps' District Safety Officer and Bonneville's safety official responsible for the geographical area involved.

3. EMERGENCY RESPONSE AND PAYMENT

The Parties shall perform emergency M&R work subject to this section. Bonneville shall perform emergency M&R work at the Corps' facilities, so long as Bonneville determines that qualified personnel and adequate equipment are available. Such emergency requests shall be submitted by the Corps' Project Operations Manager or designated representative whenever the circumstances are such that it would cause undue hardship or delay to the Corps to dispatch its own personnel to perform the necessary emergency repairs.

Requests for emergency M&R work may be submitted orally by the Corps' Project Operations Manager or designated representative to the CSE, and the Corps shall follow-up such request with written confirmation to Bonneville within a reasonable time following the request.

The Corps will provide a Government Order to cover the work within a reasonable time after commencement of any emergency M&R work by Bonneville. However, the Corps shall be liable for payment for all emergency M&R work authorized by the Corps' Project Operations Manager or designated representative, whether or not a Government Order is in place.

(a) All such requests for emergency M&R work shall, to the extent possible, describe the details of the work needed, the type of equipment needed, the timeline for work to be made, and the number of persons necessary for the requested work. The Corps shall provide Bonneville with instructions or specialized information that will facilitate the emergency M&R work.

(b) Upon determining that qualified personnel and adequate equipment are available, Bonneville shall perform the requested emergency M&R work to the Corps' facilities. In the performance of such emergency M&R work, Bonneville shall: (i) furnish a foreman or other person who shall be directly in charge of Bonneville personnel; and (ii) abide by prudent utility practices in the manner and quality reasonably dictated by the circumstances.

(c) The Corps shall pay Bonneville as determined in accordance with Section 2(b) and (c) and Section 4.

4. PAYMENT PROVISIONS

(a) **General**

All collection transactions will be processed via the Intra-governmental Payment and Collection (IPAC) system or by other mechanisms as mutually agreed to in writing by the Parties. When Bonneville accepts the Government Order submitted by the Corps, Bonneville's accounting information and appropriation must be provided to the Corps for entry into the Corps of Engineers Financial Management System (CEFMS). This will ensure timely payment through IPAC.

Both Parties will adhere to the mandatory requirements established by the Financial Management Service and any special requirements established by each of the Parties for processing transactions via IPAC.

If there are questions about IPAC charges, the Corp should contact Bonneville and discuss the issue prior to processing an adjustment in IPAC.

(b) **Payment by the Corps**

Bonneville will provide an invoice for the M&R work in accordance with Section 2(b) and initiate an IPAC collection on the invoice due date or within 30 days of submitting the invoice.

(1) Bonneville shall collect via IPAC and include the following information:

a. Corps Government Order Number;

b. Corps FEM Job Order Number (if applicable);

c. Corps Agency Location Code;

d. Accounting and Appropriation Data;

e. Time period covered by the billing;

f. Project name.

(2) Upon written request by the Corps, Bonneville will provide the Corps an accounting of M&R work performed. Bonneville's invoice for each project shall be sent to the Corps at the address shown on the Government Order for the M&R work.

For assistance with IPAC billings, contact Bonneville Finance, Cash & Treasury Management organization at treas@bpa.gov or at (503)230-3574.

5. OWNERSHIP OF FACILITIES

The Corps shall retain ownership of the facilities and equipment it owned prior to the performance of M&R work by Bonneville. Any equipment installed by Bonneville in the Corps' facilities which is not otherwise identified by addendum to this agreement shall become the property of the Corps upon installation.

6. PERMIT

A permit for the purpose of inspecting equipment and performing M&R work under this Agreement, together with the right of ingress and egress at all reasonable times, is granted by the Corps to Bonneville, its employees, contractors and representatives during the term of this Agreement. Such permit, and access pursuant to the permit, shall be subject to the safety and security procedures specified in section 2(f) of this Agreement. Bonneville shall give the Corps reasonable oral notice prior to entering its property. Bonneville shall also have the right to inspect and copy and rely upon all records, diagrams, blueprints and other documents that pertain to the M&R work at the Corps' facility receiving the services, including without limitation those identifying prior maintenance on the facility. The Corps shall not unreasonably withhold such records. The Corps shall cooperate and assist in Bonneville's review of applicable records. All such records, diagrams, blueprints and other documents shall be considered sensitive and shall not be released by Bonneville to nonfederal entities or persons other than contractors performing work under this Agreement without the prior approval of the Corps, unless required by federal law or court order.

7. NOTICES AND CONTACTS

(a) **Notices**

Any notice, request, demand or statement which may be given to or made upon either Party by the other Party under any of the provisions of this Agreement shall be in writing, unless otherwise specified in this Agreement as verbal and shall be delivered in person; or with proof of receipt by a nationally recognized delivery service or by United States Certified Mail. Notices are effective when received. Either party may change the name or address for receipt of notice by providing notice of such change. The parties shall deliver notices to the following persons and addresses as appropriate:

If to Bonneville:

Attention: Transmission Account Executive for U.S. Army Corps of Engineers – TSE/TPP-2
Phone: (360) 619-6016
Fax: (360) 619-6940

If by First Class Mail:
Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666-1409

If by Overnight Delivery Service:
Bonneville Power Administration – TSE/TPP-2
7500 NE 41st Street, Suite 130
Vancouver, WA 98662-7905

If to the Corps:

US Army Corps of Engineers
Attn: CENWP-OD
P.O. Box 2946
Portland, OR 97208-2946

US Army Corps of Engineers
Attn: CENWS-OD
4735 East Marginal Way South
Seattle, WA 98134-2385

US Army Corps of Engineers
Attn: CENWW-OD
201 North Third Avenue
Walla Walla, WA 99362-1876

(b) **Local Contacts and Facilities**

A listing of local contacts for M&R work at the Corps' facilities, including contacts in the event of an emergency at designated facilities will be at the Corps' Hydropower Facilities within the FCRPS and/or the Corps' District Operations Division.

8. MISCELLANEOUS

(a) **Audit Rights**

(1) Bonneville shall maintain complete and accurate files and records concerning all M&R work provided and all amounts billed under this Agreement. Records regarding costs chargeable pursuant to this Agreement shall be maintained in accordance with generally accepted accounting standards. Bonneville shall maintain such files and records for at least two years after the completion of M&R work performed pursuant to this Agreement. The Corps, at its own expense, shall have the right, at any reasonable time, upon reasonable

written notice, and in conformance with generally accepted auditing standards, to inspect and audit those Bonneville records during the course of work and throughout the two-year retention period after the completion of such work. Bonneville shall accommodate such inspection and audit.

(2) If there are any inaccuracies in the billings, the necessary adjustments shall be made for inaccuracies discovered during an audit and/or the two year retention period.

(b) **Dispute Resolution**

(1) Pending resolution of a disputed matter, the Parties will continue performance of their respective obligations, including payment, under this Agreement.

(2) In the event of a dispute arising out of this Agreement, both Parties shall negotiate in good faith to reach an acceptable and timely resolution of the dispute.

(c) **Liability**

(1) The Parties agree that all non-federal personnel, including all contractor and subcontractor personnel, performing duties under this agreement on federal property, shall be required to and shall carry minimum insurance amounts, covering the Parties and the United States Government as co-insured parties, in at least the following types and sums:

a. **Workmen's Compensation Insurance and Employer's Liability**
Contractors are required to comply with applicable Federal and State worker's compensation statutes. Employer's liability coverage of at least $100,000 shall be required.

b. **General Liability**
The contractor shall provide general liability insurance of at least $1,000,000 per occurrence. Any policy aggregate limits that apply shall be modified to apply to each location and project.

c. **Watercraft Liability**
The contractor shall provide watercraft liability insurance. Limits shall be at least $1,000,000 per occurrence.

d. **Environmental Liability**
The contractor shall provide environmental impairment liability insurance of at least $1,000,000 per occurrence. Such

insurance will include coverage for the clean up, removal, storage, disposal, transportation, and/or use of pollutants.

e. **Professional Liability**
The contractor shall provide professional liability insurance. Coverage shall be at least $1,000,000 per occurrence for claims arising out of negligent acts, errors and omissions.

Before commencing work on the Corps' facilities covered under this Agreement, the contractor shall provide to Bonneville and the Corps certificates of insurance from the insurance company stating the required insurance has been obtained and is in force. The certificate(s) shall identify the contractor and the contract(s) for which coverage is provided, and shall contain a statement that the insurer will give Bonneville and the Corps notices of cancellation or any material change at least 30 days before the effective date. In addition, the contractor shall provide certificates as the policies are renewed throughout the period of the contract. If the contractor's insurance does not cover the subcontractors involved in the work, the contractor shall provide certificates stating that the subcontractors have obtained the required insurance.

(d) **Section Headings**
Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of text.

(e) **Waiver**
Any waiver at any time by any Party of its rights with respect to a default under this Agreement, or with respect to any other matters arising in connection with this Agreement, shall only be effective if given in writing and shall not be deemed as a waiver with respect to any subsequent default of any other matter.

(f) **Complete Agreement**
Existing task orders under current agreements in place prior to the execution of this Agreement shall be performed and completed pursuant to their terms. This Agreement, including documents expressly incorporated by reference, constitutes the entire agreement between the parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement. However, existing M&R work under agreements in place prior to the execution of this Agreement shall be performed and completed pursuant to their terms.

(g) **No Oral Modification**
No modification to this Agreement shall be valid unless it is in writing.

(h) **Counterparts**
This Agreement may be executed in multiple counterparts that shall each be binding.

(i) **Third Party Beneficiaries**
This Agreement is made and entered into for the sole benefit of the Parties, and the Parties intend that no other person or entity shall be a direct or indirect beneficiary of this Agreement.

(j) **Existing Rights and Authorities**
Except as specifically stated herein, nothing herein affects the existing rights, authorities, and responsibilities of the Parties, or their relationships with third parties.

9. SIGNATURES
The signatories represent that they are authorized to execute this Agreement on behalf of the party for which they sign.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of the Army

By: **/S/ WILLIAM E. RAPP**

Name: William E. Rapp, P.E.
(Print/Type)

Title: Brigadier General, US Army
Division Engineer

Date: **29 May 2009**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: **/S/ CHARLES R. SWEENEY**

Name: Charles R. Sweeney
(Print/Type)

Title: Transmission Account Executive

Date: **5/27/2009**

RKadow:slv:6060:5/20/2009 (W:\TMC\CT\US COE\Contracts (Final)\13663 MOA Maint&Repair.doc)

Contract No. 14-03-19250

11-4-70

MEMORANDUM OF UNDERSTANDING

executed by the

BONNEVILLE POWER ADMINISTRATOR

UNITED STATES DEPARTMENT OF THE INTERIOR

and the

DIVISION ENGINEER, NORTH PACIFIC DIVISION

CORPS OF ENGINEERS, UNITED STATES DEPARTMENT OF THE ARMY

(AUTHENTICATED COPY) Contract No. 14-03-19250

11-4-70

MEMORANDUM OF UNDERSTANDING

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This MEMORANDUM OF UNDERSTANDING, executed November 16, 1970, by the BONNEVILLE POWER ADMINISTRATOR (hereinafter called "the Administrator"), United States Department of the Interior, and the DIVISION ENGINEER, NORTH PACIFIC DIVISION (hereinafter called "the Division Engineer"), Corps of Engineers, United States Department of the Army,

W I T N E S S E T H:

WHEREAS certain statutes provide that various projects constructed in the States of Washington, Oregon, Idaho, and Montana by the Department of the Army shall be operated and maintained under the direction and supervision of the Corps of Engineers (hereinafter called "the Corps"); and

WHEREAS the projects set forth in Exhibit A of this memorandum ("Projects") have been or are being so constructed or have been authorized, and the responsibility for the operation and maintenance of said Projects has been delegated to the Division Engineer; and

WHEREAS the Administrator is authorized pursuant to law to dispose of the electric energy generated from said Projects, surplus to the energy required for their operation and maintenance; and

WHEREAS certain statutes provide that various projects constructed in the Pacific Northwest by the Department of the Interior shall be operated and maintained by the Secretary of the Interior and the Administrator is authorized pursuant to law to dispose of the electric energy generated from such projects; and

WHEREAS within the project limitations established by the Corps the Administrator coordinates the operation of the Projects listed in Exhibit A with certain other interconnected projects operated by the Department of

the Interior, so that all of such projects are operated as parts of a single interconnected system, known as the Federal Columbia River Power System; and

WHEREAS the Administrator coordinates the power operation of the Federal Columbia River Power System with certain non-Federal hydroelectric and thermal projects including those thermal projects to be constructed under the Hydro-Thermal Program approved by the Department of the Interior on October 27, 1969; and

WHEREAS the parties hereto in conjunction with all of the operators of the major electric plants and systems which serve the Pacific Northwest area have in the past coordinated operation of their facilities through various other contracts and arrangements which culminated on September 15, 1964, in the Pacific Northwest Coordination Agreement effective until June 30, 2003; and

WHEREAS the Corps recognizes the Administrator's responsibility under that agreement to schedule electric power and energy to and from the systems of other parties and to coordinate the power operation of the Projects; and

WHEREAS the Administrator recognizes the Corps' responsibility under that agreement to preserve the priority of nonpower uses or functions as appropriate to assure utilization of the resource for other purposes; and

WHEREAS the United States of America and Canada have entered into the "Treaty between Canada and the United States of America Relating to the Cooperative Development of the Water Resources of the Columbia River Basin;" and

WHEREAS, on September 16, 1964, Executive Order No. 11177 designated the Administrator Chairman and the Division Engineer the other member of the Unites States Entity under that Treaty; and

WHEREAS, on October 16, 1964, the Administrator and the Division Engineer by a memorandum entitled "Responsibilities of the United States Entity" agreed that matters which are exclusively related to flood control will be the primary responsibility of the Division Engineer, matters which are exclusively related to power will be the primary responsibility of the Administrator, and in the event that there should arise a question of precedence between a flood control responsibility and a power responsibility, precedence shall be given to flood control; and that other matters to be implemented in accordance with the Treaty and which affect the interests of the Department of the Interior and the Army shall be carried out jointly by the Administrator and the Division Engineer; and

WHEREAS the National Environmental Policy Act of 1969, approved January 1, 1970, affects the operations of the parties hereto and said parties shall act in compliance with the provisions of that Act; and

WHEREAS the Administrator and the Division Engineer have consulted and will continue to consult on the loads and resource requirements of the Federal Columbia River Power System; and

WHEREAS the Division Engineer and the Administrator desire to meet the above recited obligations effected since the Memorandum of Understanding cited below and that certain procedures be implemented to obtain an improved working relationship between the staff elements of the Corps and of the Administrator; and

WHEREAS the parties hereto executed a Memorandum of Understanding (designated as Contract No. 14-03-001-12730) on October 8, 1956, and said parties desire to terminate said Memorandum;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Termination of Memorandum. Contract No. 14-03-001-12730 is hereby terminated as of the time this Memorandum of Understanding takes effect.

2. Term of Memorandum. This memorandum shall be effective commencing on the date of execution and shall remain in effect until terminated upon 90 days prior written notice by either party.

3. Availability of Energy.

(a) The Division Engineer, during the term of this memorandum, shall make available to the Administrator all of the electric power and energy available at the Projects listed in Exhibit A (attached hereto and hereby made a part of this memorandum), in excess of the amounts reserved for use by the Corps, in accordance with schedules provided by the Administrator and mutually agreed upon by the Administrator and the Division Engineer. The parties hereto agree to supersede said Exhibit A with a new Exhibit A whenever it becomes necessary to do so as a result of any changes occurring with respect to an existing Project or Projects, or the addition of a new project or projects.

(b) The Corps shall make said electric power and energy available to the Administrator at mutually agreeable points at or in the vicinity of the generating plants of said Projects, as three-phase alternating current, at a frequency of approximately 60 hertz and at nominal delivery voltages within range of the facilities used by the Administrator to receive or transmit said electric power and energy, or at other mutually agreeable voltages.

(c) Subject to temporary interruption or reduction in the availability of electric power and energy which, in the opinion of the Division Engineer,

are necessary for the purpose of maintenance, replacement, installation of equipment, or investigation and inspection, and subject to emergencies, Uncontrollable Forces as defined herein, or other extraordinary conditions, the Corps shall operate the Projects so as to schedule and to make available electric power and energy as requested by the Administrator, provided that, in the opinion of the Division Engineer, compliance with such request in the operation of the Projects:

(1) would not require the safe limits of the generating, transforming and switching facilities, and appurtenant equipment of said Projects to be exceeded, or otherwise cause damage to the same;

(2) would not conflict with the statutory requirements for the operation of said Projects with regard to flood control, navigation, irrigation, recreation, or with other such purposes as said Projects are to serve;

(3) would not impair the effective operation of project fish passing facilities;

(4) would avoid, insofar as practicable, harmful effects on the environment, including established fish and wildlife resources;

(5) would not infringe upon the vested property rights of third parties; and

(6) would not be inconsiderate of the effect on downstream construction or maintenance activities.

(d) The use by the Corps of electric power and energy required for the purposes stated in section 4 hereof, and the outages contemplated by subsection (c) of this section, shall be scheduled in advance, so far as is practicable, to the end that there will be a minimum of interference

with the availability of electric power and energy to the Administrator in accordance with subsection (a) of this section.

4. Power Required in Operation of Projects. Out of the electric power and energy generated at said Projects there is reserved for the Corps such amounts of power and energy as are required for the operation of said Projects. Such reserved electric power and energy shall be available to the Corps for use by the Division Engineer for the following purposes:

(a) Construction, operation, and maintenance of dams, powerplants, locks, fishways, and appurtenant works;

(b) Domestic and commercial uses in the areas in the vicinity of said Projects now or hereafter set aside in connection with the construction, operation, or maintenance of said Projects by the Corps and for government housing, so long as such areas remain in Federal ownership or under Federal jurisdiction and are used for government housing or other purposes in connection with the construction, operation, or maintenance of said Projects; and

(c) For such other purposes as are hereafter agreed to between the Administrator and the Division Engineer.

5. Measurement of Power.

(a) Except as is otherwise provided herein, the electric power and energy to be made available hereunder to the Administrator will be measured by metering equipment furnished and maintained by the Corps. In the event that any meter or meters fail to register properly, the electric power and energy made available during such period of failure will be estimated from the best information in the possession of the Corps.

(b) The Corps will furnish the Administrator with monthly statements showing the electric power and energy made available hereunder.

6. Detailed Operating Arrangements. In order to provide for the optimum effectiveness of said Projects for power generating purposes, for other authorized project purposes, and for protection of the environment, the Division Engineer and the Administrator will establish from time to time mutually satisfactory detailed operating arrangements to be followed in the coordination of their respective responsibilities. Such detailed operating arrangements will be prepared in writing jointly by the operating staffs of both agencies as the need therefor arises, for review and written approval of the Division Engineer and Administrator. Such detailed operating arrangements when approved will be attached to this memorandum of understanding under Exhibit B (attached hereto and hereby made a part of this memorandum) and shall be subject to amendment from time to time as circumstances require with the prior written approval of the Division Engineer and Administrator.

7. Return of Power Expenses and Investment. The Administrator shall allocate to each Project sufficient revenues to pay the operation, maintenance, and interest expenses for that Project for the then current year. The consolidated financial statement for the Federal Columbia River Power System required by P.L. 89-448 will be considered to demonstrate that the Federal capital investment in the Projects will be repaid in accordance with power system repayment criteria.

8. Accounting by the Parties.

(a) The Corps will furnish the Administrator summarized financial statements, supporting schedules and operating reports with respect to

construction and operation of the Projects, and the Administrator will furnish the Corps like statements, schedules and reports with respect to the marketing of and accounting for revenues from power and energy made available to it from the Projects. Schedules for each Project will be furnished promptly after the close of each governmental fiscal year following commencement of generation and for such other periods during each year and in such form as may be mutually agreed upon from time to time.

(b) It is contemplated that the records, accounts, and reports of the Corps and the Administrator will be audited periodically by authorized representatives of the General Accounting Office.

9. License for Lines and Facilities. During the term of this memorandum the Corps will permit use by the Administrator of land under jurisdiction of the Corps in connection with the operation of the Projects necessary for the location of electric power transmission lines, control and communications lines and cables, substations, switching stations, radio stations, and appurtenances constructed or found necessary by the Administrator for construction in connection with the marketing of electric power and energy produced at said Projects. Before commencement of any construction on lands under the jurisdiction of the Corps, the Administrator will submit to the Division Engineer copies of his layout, plans, and designs, and construction activities will not be started until the Division Engineer has furnished a permit or letter to the Administrator approving the construction and the location thereof.

10. Cooperation. The Division Engineer and the Administrator will make available to each other all the information necessary for the Administrator and the Division Engineer to meet their responsibilities pursuant to law. The timely interchange of certain data and information will be necessary to

insure optimum project operation for all purposes. Accordingly, such interchange will be made promptly as pertinent data and information become available. Pertinent details and cost funding responsibility will be established by operating arrangements consummated pursuant to section 6 above. Any equipment shall be installed in such a way that there will be no adverse effect on the existing equipment of the other party. The specific information interchanged between the Administrator and the Division Engineer shall include, but not be limited to, the following:

(a) The Division Engineer will furnish data on power resources available at the Projects and data which have a bearing on loading of the plants and limitations of operation.

(b) The Administrator will furnish data on estimated Federal system load requirements, weekly issues of proposed generation assignments, and such daily loading schedules and other pertinent information as are needed permit the Division Engineer to carry out his responsibilities for ple purpose operation at the Projects.

(c) The Division Engineer and the Administrator will discuss plans for adding or changing power projects, transmission facilities, and control and communication facilities in the preliminary planning phases to ensure optimum coordination.

(d) If, in the maintenance of the respective facilities and the utilization thereof for the purposes of this memorandum, it becomes necessary by reason of any emergency or extraordinary condition for either the Administrator or the Division Engineer to request the other to furnish personnel, materials, tools, and equipment, the party so requested will cooperate with the other and render such assistance as the party so requested may determine to be available. The party making such request, upon receipt of properly

insure optimum project operation for all purposes. Accordingly, such interchange will be made promptly as pertinent data and information become available. Pertinent details and cost funding responsibility will be established by operating arrangements consummated pursuant to section 6 above. Any equipment shall be installed in such a way that there will be no adverse effect on the existing equipment of the other party. The specific information interchanged between the Administrator and the Division Engineer shall include, but not be limited to, the following:

(a) The Division Engineer will furnish data on power resources available at the Projects and data which have a bearing on loading of the plants and limitations of operation.

(b) The Administrator will furnish data on estimated Federal system load requirements, weekly issues of proposed generation assignments, and such daily loading schedules and other pertinent information as are needed to permit the Division Engineer to carry out his responsibilities for multiple purpose operation at the Projects.

(c) The Division Engineer and the Administrator will discuss plans for adding or changing power projects, transmission facilities, and control and communication facilities in the preliminary planning phases to ensure optimum coordination.

(d) If, in the maintenance of the respective facilities and the utilization thereof for the purposes of this memorandum, it becomes necessary by reason of any emergency or extraordinary condition for either the Administrator or the Division Engineer to request the other to furnish personnel, materials, tools, and equipment, the party so requested will cooperate with the other and render such assistance as the party so requested may determine to be available. The party making such request, upon receipt of properly

itemized bills from the other party, will reimburse the party rendering such assistance for all costs properly and reasonably incurred by it in such performance, including reasonable percentage for administrative and general expenses, such costs to be determined on the basis of current charges or rates used in its own operations by the party rendering assistance.

11. Uncontrollable Forces. Neither party shall be considered to be in default in respect to any obligation hereunder if prevented from fulfilling such obligation by reason of uncontrollable forces, the term "uncontrollable forces" being deemed for the purpose of this memorandum to mean any cause beyond the control of the party affected, including but not limited to flood, earthquake, storm, lightning, fire, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, proceeding by court or public authority, or act or failure to act by court or public authority, which uncontrollable forces, by exercise of due diligence and foresight, such party could not reasonably have been expected to avoid. Either party rendered unable to fulfill any obligation by reason of uncontrollable forces shall exercise due diligence to remove such inability with all reasonable dispatch.

IN WITNESS WHEREOF, the parties hereto have executed this memorandum in several counterparts.

UNITED STATES OF AMERICA

Department of the Interior

(SEAL)

By /S/ H. R. RICHMOND
Bonneville Power Administrator

Department of the Army,
Corps of Engineers

(SEAL)

By /S/ ROY S. KELLEY
Division Engineer
North Pacific Division

EXHIBIT A

PROJECTS OF THE CORPS

COMPLETED, UNDER CONSTRUCTION, OR AUTHORIZED

Albeni Falls

Asotin

Big Cliff

Bonneville

Chief Joseph

Cougar

Detroit

Dexter

Dworshak

Foster

Green Peter

Hills Creek

Ice Harbor

John Day

Libby

Little Goose

Lookout Point

Lost Creek

Lower Granite

Lower Monumental

McNary

Strube

The Dalles

EXHIBIT B
Revised 2-1-71

DETAILED OPERATING ARRANGEMENTS

Attached to this Exhibit B are the following operating arrangements, and amendments thereto:

Attachment		Effective Date
1.	Reservoir Regulation and Power Scheduling	November 16, 1970
2.	Spinning Reserve and Other Reserve Capability	November 16, 1970
3.	Powerhouse Control	November 16, 1970
4.	Dispatcher-Operator Working Relations	November 18, 1970
5.	Data Acquisition, Engineering, and Planning	December 1, 1970
6.	Relationship of Hydromet Data to Powerhouse Data System	January 1, 1971
7.	Joint Weather and Streamflow Forecasting	January 1, 1971
8.	Generation and Transmission Relationship	February 1, 1971
9.	Operation During Emergency Conditions	February 1, 1971

AUTHENTICATED COPY

Attachment No. 1 to Exhibit B of
Contract No. 14-03-19250
Effective Date: November 16, 1970

OPERATING ARRANGEMENT
(Reservoir Regulation and Power Scheduling)

SUBJECT: Principles and Procedures Relating to Reservoir Regulation and Power Scheduling of Corps of Engineers Hydroelectric Projects within the Bonneville Power Administration's Marketing Area

1. This Operating Arrangement is made pursuant to paragraph 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer.

2. General. The North Pacific Division (NPD) Reservoir Control Center and the Bonneville Power Administration (BPA) Branch of Power Supply and Scheduling have agreed upon certain principles and procedures of reservoir regulation and power scheduling of NPD hydroelectric projects within the BPA marketing area. These principles and procedures, as set forth below, are applicable to the 1970-71 Operating Year. They will be reviewed at the end of the Operating Year and revised as desired in a manner agreeable to both agencies. In the event agreement cannot be reached on desirable revisions, these principles and procedures may be terminated.

3. Principles. The BPA Branch of Power Supply and Scheduling and the NPD Reservoir Control Center are in agreement on the following principles:

(a) BPA has the responsibility for marketing and transmitting power generated at NPD projects.

(b) NPD Corps of Engineers has the responsibility for operation of its projects for all authorized purposes.

(c) In order to market power from NPD projects, BPA must prepare daily schedules of the desired power generation of NPD projects.

(d) In order to obtain the best overall project operation for all authorized purposes, NPD must plan the daily regulation of its reservoirs.

(e) The daily power scheduling and reservoir regulation planning normally requires more than a single working shift and the two agencies have power scheduling and reservoir regulation personnel on duty until at least 2100 hours of each work day during the storage control season.

(f) BPA coordinates the power operation of NPD projects with certain hydroelectric projects of the Bureau of Reclamation and with hydroelectric and thermal plants owned and operated by the Washington Public Power Supply System and the City of Seattle and will coordinate such projects with thermal projects to be constructed under the Hydro-Thermal Program.

(g) NPD is responsible for the electrical generation at each of its projects.

(h) Both BPA and NPD are parties to the Pacific Northwest Coordination Agreement, and:

(1) NPD recognizes BPA's responsibility under that agreement to schedule power to and from the system of other parties in order to coordinate the power operation of NPD projects.

(2) BPA recognizes NPD's responsibility under that agreement to preserve the priority of nonpower uses or functions as appropriate to [illegible]zation of the resource for other purposes.

(i) BPA has entered into contracts to deliver power over the Pacific Northwest-Pacific Southwest Intertie and is entering into contracts to supply peaking power and forced outage reserves under the Hydro-Thermal Program; and the obligations assumed by BPA under such contracts depend, in part, upon the power output from NPD projects.

(j) Power scheduling and reservoir regulation planning for the large system of projects involved requires the rapid interchange of large quantities of data. The two agencies have provided a telephone line interconnection between terminals on their two computers to facilitate such exchange on a limited basis with existing facilities. This interconnection will be improved within the coming year in order to make possible the interchange of larger quantities of data.

(k) BPA and NPD have consulted and will continue to consult on the loads and resource requirements of the Federal Columbia River Power System.

4. Procedures. To enhance the working relationship between the NPD Reservoir Control Center and the BPA Power Scheduling Section, the following procedures will be implemented:

(a) NPD will prepare and make available to BPA an interim tabulation of Normal Operating Limits for each of the NPD hydroelectric projects within the BPA marketing area. NPD will undertake a comprehensive review of all project Normal Operating Limits. Subsequent changes of and additions to the Normal Operating Limits will be transmitted by letter from the Division Engineer to the Bonneville Power Administrator.

(b) The NPD Reservoir Control Center will notify the BPA Power Scheduling Section of any Special Operating Limits which in the opinion of NPD are necessary to achieve the best overall multiple purpose operation of its projects. Such notification will be made as soon as each Special Operating Limit becomes known to NPD. Written or teletype confirmation of each Special Operating Limit will be transmitted by NPD to BPA. Such notifications and confirmations will include: the nature of the limit; the firmness of the limit; its probable duration; and the reason for the limit. Whenever time permits, the NPD Reservoir Control Center will consult with the BPA Power Scheduling Section before each Special Operating Limit is established and will discuss alternative actions, benefits, and reasons for establishing each limit. NPD will make every effort to review the Special Operating Limits currently in effect and make available to BPA by 1000 hours each normal working day any other Special Operating Limits for the following day's power schedule. Changes or additions to Special Operating Limits which arise after 1000 hours may be made by NPD until 1600 hours, after which no changes or additions will be made except for emergencies. In the event any Normal or Special Operating Limit is significantly exceeded as a result of power operation, BPA will notify NPD by teletype of the reason therefor no later than two working days after such event.

(c) By 1000 hours each normal working day, the BPA Power Scheduling Section will consult with the NPD Reservoir Control Center on both the current and the near-future power situations. At the time the BPA Power Scheduling Section will also provide the NPD Reservoir Control Center with

a preliminary estimate of their system energy and peaking generation requirements for the next day; the current and scheduled loadings of the Hungry Horse, Boundary, Hanford, and Grand Coulee Projects, and the status of the Grand Coulee pumps and the Pacific Northwest-Southwest Intertie; and other significant items that may affect the immediate power situation. Until such time as the BPA Power Scheduling Section is able to provide sufficient staff to update a plant scheduling study at the beginning of each work day, the preliminary estimates provided to the NPD at 1000 hours each day will, of necessity, be based on the BPA plant scheduling study made the day before. NPD will take into consideration the preliminary nature of such estimates and will govern their use accordingly. In addition, the BPA Power Scheduling Section will inform the NPD Reservoir Control Center of the changes in the scheduled loadings of these projects, pumps, and intertie. The NPD Reservoir Control Center will use such information to estimate the next day's hydraulic operation of each NPD project and the resulting downstream flows and river stages.

(d) The BPA Power Scheduling Section will make available via computer terminal data transmission facilities a complete, detailed listing of the input and output from the BPA plant scheduling computer run. Such listing will be made available each normal working day as soon as it is completed. BPA will make every effort to have such listing available for transmission by 1800 hours.

(e) The NPD Reservoir Control Center will review the BPA Computer listing. The NPD Reservoir Control Center may modify the BPA plant loading schedules for NPD projects provided such modifications do not result in

decreased load-carrying capability of the Federal system. However, modifications which affect load-carrying capability may be made in such schedules when required by emergency conditions which were unforeseen at the time the Special Operating Limits were prescribed. The NPD Reservoir Control Center will telephone any required modifications in plant loading schedules to the BPA Power Scheduling Section within two hours of receipt of the BPA plant scheduling run.

(f) Information will normally be exchanged between working-level personnel in the BPA Power Scheduling Section and the NPD Reservoir Control Center. In the event that there is a conflict between the hydraulic operation of a NPD project desired by the NPD and that operation that would result from following the plant loadings which BPA desires to schedule, that conflict will be referred immediately by the working-level personnel in each agency to the representative or his alternate listed below under Level One. The person in each agency to whom the conflict is referred will consult by telephone with his counterpart. Every effort will be made by both representatives to resolve the conflict to the satisfaction of both agencies. However, should the conflict fail to be resolved after 15 minutes of telephone consultation, the conflict will be referred to the representative or his alternate listed under Level Two. Again, the agency representatives will consult by telephone in an attempt to resolve the conflict. Failing resolution within one hour of referral, this conflict will be referred within the NPD to the Division Engineer and within BPA to the Administrator.

Level One	North Pacific Division	Bonneville Power Administration
Representative:	C. Hildebrand	L. Bissell
Alternate:	M. Larson M. Nelson D. Lewis	H. Nystrom C. Blake L. Dean
Level Two		
Representative:	Gordon Fernald	Bernard Goldhammer
Alternate:	Robert Baunach	Hector Durocher

APPROVED /S/ H. R. RICHMOND
Administrator
Bonneville Power Administration

APPROVED /S/ ROY S. KELLEY
Division Engineer
North Pacific Division

AUTHENTICATED COPY

Attachment No. 2 to Exhibit B of
Contract No. 14-03-19250
Effective Date: November 16, 1970

OPERATING ARRANGEMENT
(Spinning Reserve and Other Reserve Capability)

SUBJECT: Principles and Procedures for Scheduling Spinning Reserve and Other Reserve Capability and for Establishing Methods of Controlling Spinning Reserve

1. This Operating Arrangement is made pursuant to paragraph 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer.

2. General. The North Pacific Division (NPD) Operations Division and the Bonneville Power Administration (BPA) Branch of System Operations have agreed upon certain principles and procedures for controlling reserve generating capacity of NPD hydroelectric projects within the BPA marketing area. These principles and procedures, as set forth below, are applicable to the 1970-71 operating year. They will be reviewed at the end of each operating year and revised in a manner agreeable to both agencies.

3. Principles. The BPA Branch of System Operations and the NPD Operations Division are in agreement on the following principles:

A. BPA has the responsibility for maintaining reserve generating capacity in accordance with criteria established by:

(1) The Northwest Power Pool,

(2) The WSCC Operations Committee, and

(3) The Pacific Northwest-Pacific Southwest Intertie parties.

B. NPD will provide BPA with reserve generating capacity from its projects with due consideration for equipment limitations, operating efficiencies and nonpower constraints.

C. Reserve generating capacity available from NPD projects (Operating Reserve) shall consist of:

(1) Spinning reserve - that unloaded generating capacity (using maximum overload ratings designated) connected to the power system and on the BPA load frequency controller, and

(2) Nonspinning reserve - that generating capacity (using any extra-overload capacity designated) available within a 5-minute period from:

(a) Generators already carrying load but not on the controller, and

(b) Generators on "standby," capable of being started upon call, synchronized to the system, and loaded.

D. NPD has agreed to provide BPA with current information on the amount of each type of reserve generating capacity available from each NPD project.

4. Procedures.

A. NPD normally operates its generating units at each project within best efficiency range and connected to the load controller. This operation normally provides spinning reserves in excess of minimum system requirements. Generating units will normally be added to or removed from the system to maintain operation in the best efficiency range. For situations requiring greater spinning reserve than normally provided by generating units operating within their best efficiency range, NPD will allow the operation of additional units, providing equipment limitations and nonpower constraints are observed.

B. When all available units are in service, the BPA dispatcher will limit loads to assure the maintenance of adequate spinning reserve capacity. This spinning reserve capacity will include the extra-overload capacity available from specific projects that have units capable of exceeding their normal overload ratings. The amount of extra-overload capacity depends upon the net head at each project. Extra-overload capacity will be used only during system emergencies that occur during very heavy load periods. It will be used only on an immediate basis to allow time for other measures to be taken. BPA has made necessary adjustments in its operation of the existing generation allocation console to make this extra-overload capacity usable. NPD has made adjustments in unit and plant limits to make extra-overload capacity available as follows:

Chief Joseph	16 Units (83.2-80)	=	50 MW
McNary	12 Units (90 - 80)	=	120 MW
The Dalles	14 Units (97 - 90)	=	100 MW
John Day	To be determined		
Lower Monumental	To be determined		
Little Goose	To be determined		

C. BPA will maintain at all times a minimum spinning reserve capacity on the controller ready to assume load. This minimum spinning reserve capacity is to be equal to 25 percent of the maximum first contingency outage plus 1 percent of estimated daily peak generation for regulating margin.

D. NPD will furnish BPA the following information from each NPD project:

(1) Total number of units connected to the power system (on the line).

(2) Number of units on line and on control.

(3) Number of units off line, on standby, and available for service.

(4) Capacity (including extra-overload) of units on line and on control plus load of units on line but not on control (BPA computes spinning reserve using this quantity and the total plant load quantity which is presently telemetered to BPA).

(5) Reserve capacity of units on line but not on control, and

(6) Capacity of units available but not on line. (The quantities in (5) and (6) provide BPA with the amount of non-spinning reserve available.)

E. At the present time, this information is provided by hourly telephone calls or teletype messages.

F. As soon as logic equipment presently on order by both agencies can be placed in service, the above information will be transmitted to BPA by telemetry. This information in part or in total will, at this stage, still be manually input from some NPD projects.

G. As soon as the necessary design and construction can be completed by NPD (est. 6-8 months) in the projects connected to the load controller, the information in D(1) and D(2) above will be automatically telemetered from the projects which are capable of being

controlled from the BPA load controller to the BPA Operations computer and will be in digital form so that the BPA computer can automatically calculate an updated spinning reserve capacity.

H. The John Day and the Lower Snake plant computers are presently receiving all of the above information. As soon as BPA can obtain the necessary equipment to interface with NPD plant computers, the above information will be telemetered to BPA.

I. NPD is planning to install plant computers for The Dalles (December 1972) and Chief Joseph (FY 1976) and has plans for others in the future. The details of the computer interfacing will be worked out. Use of other NPD plants (those not equipped for load control) to supply spinning reserve will await future decisions.

APPROVED /S/ H. R. RICHMOND
Administrator
Bonneville Power Administration

APPROVED /S/ ROY S. KELLEY
Division Engineer
North Pacific Division

AUTHENTICATED COPY

Attachment No. 3 to Exhibit B of
Contract No. 14-03-19250
Effective Date: November 16, 1970

OPERATING ARRANGEMENT
(Powerhouse Control)

SUBJECT: Principles and Procedures Relating to Powerhouse Control Including Load-Frequency Control of Individual Powerhouses and Groups of Powerhouses

1. This Operating Arrangement is made pursuant to paragraph 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer.

2. General. The North Pacific Division (NPD) Operations Division and Engineering Division and the Bonneville Power Administration (BPA) Branches of System Operations, Power System Control, and Power Supply and Scheduling have agreed upon certain principles and procedures relating to Powerhouse Control. These principles and procedures, as set forth below, are applicable to the 1970-71 operating year. They will be reviewed at the end of each operating year and revised in a manner agreeable to both agencies.

3. Principles. BPA and NPD are in agreement on the following principles:

(a) The efficient operation of the Federal Columbia River Power System requires that operation of the various resources available to the system be coordinated through a central entity which can monitor and control them in response to the dynamic state of power loads, natural streamflows, reservoir storage and transmission line loading as appropriate. The BPA System Control Center will be responsible for such coordination.

(b) NPD and BPA are in continuing agreement, along with the Bureau of Reclamation, on the use of tie-line bias control as the method for providing load-frequency control (LFC).

(c) NPD has the responsibility for multipurpose operation of its projects and for procedures relating to the regulation of generation within the various powerplants.

(d) BPA and NPD will continue to cooperate in developing generation and load-dropping schemes, system damping controls, and voltage control schemes as required to provide power system stability and integrity.

(e) BPA recognizes the position of NPD with respect to group control of the Lower Snake plants and will cooperate in developing procedures to control these plants remotely through the McNary powerhouse computer so as to provide LFC from the BPA System Control Center.

(f) NPD recognizes the need of BPA to have generating capacity at reservoir powerhouses available for spinning reserve even though certain plants may be unsuitable for normal LFC.

4. Procedures.

(a) The BPA-NPD Coordination Task Force No. 2 completed documentation of five functional control schemes applicable to powerhouses. Historical references are included, as are the requirements and methods for both present procedures and planned future improvements for:

(1) External load-frequency control.

(2) Internal regulation of generation.

(3) Emergency dropping of generation and loads.

(4) Providing system damping.

(5) Voltage control.

Copies of this documentation are attached hereto as Exhibits 1 through 5 and adequately set out the procedures for this function.

(b) To provide for the control of the Lower Snake River plants as a group from the McNary process computer, BPA and NPD agree to proceed as follows (see Exhibit 6):

(1) Generation schedules and inflow forecasts for individual Lower Snake River plants will be developed by the BPA Power Scheduling Section after consultation with the NPD Reservoir Control Center in accordance with provisions of Attachment No. 1.

(2) The total generation schedule and inflow forecast for the Lower Snake System will be transmitted to McNary as soon as possible after 1800 each day preceding the schedule with updating as may be developed subsequently.

(3) The McNary computer will allocate generation among the plants in the most efficient manner possible in accordance with:

(i) The single instantaneous load control deviation signal from the BPA System Control Center.

(ii) The schedule of total generation including any updating.

(iii) Operational limits.

(4) NPD will make every effort to complete its initial program for control of the Lower Snake River plants by December 31, 1970, in order to provide automatic control from, and reserve generating capacity information to, the BPA System Control Center.

(c) To provide for use of generating capacity at reservoir powerhouses as spinning reserve, BPA and NPD will cooperate in developing a method of automatically loading such plants during system emergencies (see Exhibit 7).

APPROVED /S/ H. R. RICHMOND
Administrator
Bonneville Power Administration

APPROVED /S/ ROY S. KELLEY
Division Engineer
North Pacific Division

Exhibit No. 1 to
Attachment No. 3 to Exhibit B of
Contract No. 14-03-19250

SYNOPSIS OF TASK 1.1

EXTERNAL LOAD-FREQUENCY CONTROL OF POWERHOUSES

The general objective of load-frequency control is to match generation to the changing electrical load, while conforming to hourly scheduled generation levels. Load-frequency control (LFC) in the Federal power system is based on tie-line bias control, in which the sum of frequency deviation and the total power interchange deviation constitute the system error signal. The system error signal is allocated to each of the Federal Columbia River plants and to the Snake River projects as a single plant.

A central controller at BPA in Portland transmits a continuous control signal to each controlled plant, and receives the continuous value of each plant's total output, via dual-path analog telemetering. Snake River allocation is performed from a USCE computer at McNary.

Occasional gross errors in power interchange data constitute the most serious problem of the present LFC system. BPA has several solutions to this problem in the developmental stage. Most other problems are also faced singly by BPA or by the USCE. Problems which are amenable to solution by joint effort are:

- Incorrect data from powerhouses (not a serious problem)
- Control failure due to dead-band (not a serious problem)
- Lack of schedule change feedback to the USCE. Automatic feedback to the Corps' Reservoir Control Center is recommended.

Improved LFC and other functions will eventually be accomplished by computers at the control center and at the powerhouses. Also, digital telemetering of LFC quantities including powerhouse generation and control signals may be accomplished. The expected benefits include more accurate control and protection against system malfunctions.

EXTERNAL LOAD-FREQUENCY CONTROL OF POWERHOUSES

1.1 External Load-Frequency Control of Powerhouses

1.1.1 Introduction and Background

1.1.1.1 Objectives

The general objective of load-frequency control (LFC) is to match generation to the changing electrical load. Part of the "load" consists of power transfers to other electric utilities, and the "generation" consists of several large interrelated powerhouses. Therefore, the objective must be restated more completely as a set of primary objectives:

(1) Control the total (net) power interchange of the BPA control area to conform to schedule.

(2) Compensate for unscheduled load fluctuations or disturbances within the BPA control area, thus performing the BPA control area's share of the regulation of system frequency.

(3) Allocate the regulation of generation among the controlled power sources (powerhouses or groups of powerhouses), so as to conform to scheduled generation levels. The schedules are prepared to provide optimum utilization of the hydraulic resources for power generation and for the nonpower uses of the river and its system of dams.

1.1.1.2 Historical Background

In earlier times, the Federal Columbia River Power System was interconnected only with the utilities of the Pacific Northwest

Region. The Federal system then had the responsibility of holding the frequency constant, while the interconnected utilities maintained scheduled total power flow in their tie lines. Now, the region is connected into a grid that covers almost all of the United States and parts of Canada. Constant ("flat") frequency control is no longer acceptable even during failure of the normal controller. System trouble elsewhere in the country could cause an intolerable increase or decrease of generation here if constant-frequency control were in use.

1.1.1.3 Tie-Line Bias Control

Load-frequency control of the Federal power system is now based on "tie-line bias" control. In this control, the error signal (actual total generation minus desired total generation) is a composite of two quantities: the deviation of total power interchange from schedule, and the deviation of system frequency from its scheduled value. The frequency deviation is multiplied by a "bias" coefficient to convert it into an equivalent megawatt quantity. Tie-line bias control is in general use throughout the United States. It was agreed to by the USCE, USBR, and BPA in 1961 for use in the Northwest Federal system. The agencies are in continuing agreement on the use of tie-line bias control. Tie-line bias control requires knowledge of power flows at all interconnection points of the control area. Multiplant control requires knowledge of the actual generation at each of the controlled power sources. Therefore, such control must emanate

from a central control point where the needed information is available on an essentially continuous basis. It is not practical to conduct tie-line bias control from individual powerhouses.

Each controlled power source is expected to conform to its "desired" total generation as determined by the load-frequency controller, on a minute-by-minute basis. It is not necessary that all power sources be under LFC because generation changes at uncontrolled plants are compensated by response in the controlled power sources.

1.1.2 Requirements

1.1.2.1 A central controller is needed to assemble all Federal system loads, tie-line power flows and generation quantities on an essentially continuous basis; digest these data and produce an area control requirement signal; and distribute the control requirement among the controlled power sources in accordance with a predetermined operating plan.

1.1.2.2 An essentially continuous control signal from the central controller to the controlled power sources is needed.

1.1.2.3 An essentially continuous feedback signal to the central controller from the controlled power sources is needed.

1.1.2.4 Adequate generator capacity on control to handle normal, expected, load-frequency control signals is necessary.

1.1.2.5 Adequate protection and limits are needed to protect the plants and the power system when LFC system malfunctions.

1.1.2.6 Backup methods for control are needed.

1.1.3 Present Load-Frequency Control Process

The present method is a semi-automatic process using analog techniques. Direct inputs to the process are both automatic and manual. Additional information input indirectly affects the load-frequency control.

1.1.3.1 Inputs, Direct, Automatic

(1) Locally measured system frequency. System frequency is also telemetered from Ross Substation as a backup.

(2) BPA-Utility power interchange quantities telemetered from each tie point.

(3) Total generation telemetered from each of the controlled power sources.

(4) Standard frequency and time signals from WWVB.

1.1.3.2 Inputs, Direct, Manual

(1) Hourly schedules of power interchange with directly connected utilities, obtained daily or oftener from BPA scheduling engineers, and set manually into the Area Control Error Console by the BPA dispatchers.

(2) Controlled power source allocator (breakpoint) settings, obtained daily or oftener as output from an off-line generation scheduling computer program. The breakpoints are set manually into the Generation Allocator Console by the dispatchers.

(3) Notifications for time correction procedures or for system time deviation adjustment are received from

American Electric Power, Canton, Ohio, or from Southern California Edison Company, Los Angeles. These notices may result in changes of scheduled system frequency.

(4) Settings for frequency bias and other control parameters, obtained annually or oftener from BPA System Operations' technical staff. The appropriate control console dials are set by the dispatchers.

(5) Estimated power flow at interchange points from which telemetering is absent or temporarily out of service, obtained by telephone from substation operators, and set manually into the Area Control Error Console by the dispatchers.

1.1.3.3 Inputs, Indirect

(1) Information used by dispatcher in his operation of LFC equipment:

- Special instructions obtained daily or oftener from the scheduling engineers.
- Notification of observed abnormal conditions, obtained directly or by telephone from field personnel.
- Requests for special operating conditions from other utility dispatchers, powerhouse operating personnel, test engineers, and others.

(2) Information used by dispatchers and scheduling engineers to predict the need for schedule changes, and to compute the changes:

- Actual hourly power generation at each major power source.
- Actual water surface elevation readings at critical locations such as forebays of controlled powerhouses.
- Target forebay elevations, obtained daily or oftener as output from the generation scheduling process.
- Requests for interchange schedule adjustments, obtained from other utility dispatchers.

(3) Information used by dispatchers and maintenance personnel for checking the operation of the LFC system:

- Actual hourly power interchange at each tie point.
- BPA-Utility inadvertent interchange.

1.1.3.4 Method of Operation

Load-frequency control consoles at the BPA system control center at Portland now control the total power output of each Federal Columbia River powerhouse, and also control the output of the Lower Snake River powerhouses as a group. Allocation of generation for the individual Lower Snake River plants is performed by the USCE, utilizing a computer at McNary.

Analog-telemetered power interchange quantities, system frequency, and manually set schedules of interchange and frequency are combined in a control console which computes a continuous value of Area Control Error. The A.C.E. is "filtered" to remove the useless cyclic component of the signal. The A.C.E. is used in combination with scheduled generation levels, actual generation as telemetered and totalized, and participation as scheduled, to derive a "Station Control Error" quantity for each controlled power source. This quantity is telemetered to each control power source to regulate generation.

At the controlled power sources the error signals are converted to control pulses which operate the governor speed-setting motors to change unit generation. Another control system simultaneously keeps outputs of all controlled units at each plant approximately uniform.

1.1.3.5 Problems of Existing System

The following paragraphs discuss items that have been the subject of concern in operation of the existing LFC system. The intent is to explore each item in sufficient detail to determine if a solution is necessary as part of future developments.

(1) Incorrect data from tie points - The summation of power flows at the approximately 90 BPA-utility tie points is one of the principal quantities used in generation control. Errors in individual tie-line telemetered quantities produce errors in generation which in turn result in frequency errors and high

inadvertent power flows. Several safeguards exist at present against gross errors, but many instances of trouble still occur. In addition, small measurement and telemetering inaccuracies need to be reduced to a minimum. This problem is BPA's responsibility, however, and not amenable to solution by this joint task force.

(2) Incorrect data from powerhouses - Input data from powerhouses with present LFC system consists of total plant generation. This information is obtained by summing high-response thermal converter or watt transducer outputs for each unit and inputting the resultant MV signal to an analog telemetering system for transmission to the load-dispatcher's office. Overall accuracy of the data is in the range of 1 to 2 percent. Although necessary to properly divide the total load among the controlled plants, this data is not directly involved in the regulating process. Such errors are therefore not considered serious by this Task Force with the type of LFC now in use. Complete loss of signal will result in improper division of load among the other controlled plants, and experience has indicated that dual communication links are necessary. Reliability of other portions of the equipment has not been a serious problem.

(3) Control failure due to dead-band - The DIAT control at the powerhouse contains a dead-band of several megawatts, within which no control action is taken. If an Area Control Error

signal is not very large, the resulting Station Control Error signals leaving the Generation Allocator console may be within the dead-band at several or all stations. The Task Force believes that this problem is without serious consequences, as the actual Station Control Error signals typically change sign quite frequently, particularly when they are small. However, the potential exists for substantial dead-band error among the plants on control. Reduction of the overall dead-band to a practical minimum is therefore desirable as a future aim.

(4) Frequent manual adjustment of breakpoints - At present, computer output listings of console breakpoint settings are obtained only once each normal workday; however, adjustments, based upon actual and anticipated hydrologic conditions and to correct errors, are made several times each day by the dispatchers or by the scheduling engineers. Because these adjustments are based upon rules-of-thumb and scratch-paper computations, they constitute a continual additional chance for error and a degradation of the concept of computer-directed generation scheduling. Future developments should include methods of automatic readjustment to changing conditions.

(5) Lack of schedule change feedback to Corps - As a result of the frequent changes made during the day, as described in (4) above, the originally scheduled breakpoint settings which are transmitted over the CBTT are of little value to the Corps in estimating future project loadings. Since this knowledge is

necessary for proper planning of operations, accurate updating of breakpoint settings and revised station load forecasts should be furnished to the Corps' Reservoir Control Center. This updating should preferably be automatic.

(6) Incorrect station reallocation - Excess deviation of a station's total generation from the desired value presently automatically drops that station from control. The remaining plants on control are then reregulated on an allocation curve resulting from summing their station breakpoint settings into new system breakpoints. The resulting percentage participation rates are often unrealistic, and if not reset within a short time, could cause serious hydrologic unbalance in the river. In addition, design limits of the console are occasionally exceeded, degrading equipment reliability. A better method of providing for this condition is desired.

(7) Maintenance costs - The cost of maintaining the load-frequency control system in good operating condition at Chief Joseph and The Dalles averages $4,000 per year per plant. Costs at McNary and Bonneville run less than $2,000 per year per plant because they contribute less to system regulation. The major maintenance requirements are repair and adjustment of filter relays, contacts and balancing slidewires in the unit controllers. The DIAT controller has required relatively little maintenance. In considering future LFC systems, the unit controller equipment should be eliminated and balancing of load among units accomplished by some other means.

(8) Cyclic control signals - Cyclic components of the Area Control Error quantity are filtered by an "Error-adaptive Control Computer" (EACC) before the A.C.E. is sent to the Generation Allocator. However, cyclic actions by mechanical governors at the generators cause cyclic Station Control Error signals in the Generation Allocator-powerhouse feedback loop. These cyclic signals are not large, nor do they constitute a serious problem. However, they do partially defeat the purpose of the EACC which is to minimize the number of controller actions at the powerhouses, and should be eliminated if practicable.

(9) Lack of "overcontrol" limiters at powerhouses - At present, no automatic means are provided for monitoring or preventing long-term overcontrol of a project. This could result in violation of maximum or minimum station generation, discharge, or rate of change of water level limits. Such protection should be built into future systems, including provisions for operator override.

(10) Space requirements - The Area Control Error and Generation Allocator consoles are bulky and occupy increasingly valuable space in the system control center. New designs being considered should simplify the equipment and reduce physical requirements.

1.1.4 Future Developments

Both the Corps and BPA are independently planning and implementing new developments and modifications of the LFC system. Present and

possible future plans are discussed below to assist in anticipating possible conflicts.

1.1.4.1 At Powerhouses

As part of the transition from manual attended to remote automatic control of the Corps of Engineers' powerhouses, digital computers are being installed in major plants. Among the functions being assumed by this device is the load-frequency control interface. In this role, the computer will act in the capacity of the present DIAT and unit controller in accepting the control signal (either analog or digital) from the telemetering system and converting it into appropriate control signals to the governor speed level motors. This arrangement will provide solutions to the previously discussed problems of cyclic control and automatic limits through proper programing. The inherent flexibility of the computer should be ideally suited to coping with any additional problems which may arise. Ultimately, the computer will also collect the MW signals from the unit transducers, sum them and provide for outputting the totalized value to a register. This register can then be interrogated as required by the telemetering system. Present plans also include provisions for analog totalizing and telemetering of plant generation.

1.1.4.2 Developments at the System Control Center

As a part of the BPA Advanced Control and Dispatch Program, the central load-frequency control function is being developed into an all-digital process. The development is expected to occur in several phases:

(1) A digital computer program to determine Area Control Error. The most important benefit is the opportunity to apply logical data-validity checks to the power interchange information. The computer will also make the routine computations and corrections which are now performed by the dispatcher.

(2) A digital computer program to allocate generation among the several stations in accordance with a predetermined plan. This program may automatically adjust breakpoints, or it may abandon the breakpoint concept and allocate generation according to actual and predicted river and reservoir conditions, as modified by transmission system requirements. The existing problems of station dead-band, station reallocation, and correct use of the "EACC" control principle also can be solved by software methods.

(3) Digital telemetering of tie-point power flow and elimination of field subtotalization is expected to enhance both the accuracy and the reliability of these important telemetered quantities.

(4) Digital telemetering of station control signals may be accomplished at a later time, along with general development of digital equipment at the system control center and at the powerhouses.

(5) An earlier concept of hybrid analog/digital controllers at the system control center is not actively being worked on at this time. The development program includes redundancy or backup support which may include standby digital computer capability, a simplified analog controller, or both.

1.1.5 Conclusions and Recommendations

1.1.5.1 The present load-frequency control system meets the primary objectives as outlined in 1.1.1.1 in a reasonably adequate manner although considerable manual surveillance and intervention is required. It also meets the requirements listed in 1.1.2 except for 1.1.2.5; i.e., the present system does not include adequate protection and limits that are needed to protect the plants and the power system when the LFC system malfunctions. The major problem with the present LFC system is that of maintaining correct input data from tie points. A telemetering error in any one of the approximately 90 tie points introduces an error in the whole system. This is primarily a BPA problem. Other errors present lesser problems because they are either compensated for within the system or their effect is minor. Problems of major concern to the Corps are the need for breakpoint settings or anticipated loading information and the need for limit setters for functions such as maximum hourly changes in discharge. This last item could be reduced by programing such limits into the control computers presently installed or planned for all Corps plants participating in the LFC system.

1.1.5.2 Future plans of BPA and USCE in the field of load-frequency control appear compatible to this Task Force and provide potential for solution to the problems discussed above. Continued coordination and cooperation is necessary to insure successful development of the advanced system.

March 14, 1969

Exhibit No. 2 to
Attachment No. 3 to Exhibit B of
Contract No. 14-03-19250

INTERNAL REGULATION OF GENERATION

1.2 Internal Regulation of Generation

1.2.1 Introduction and Background

Regulation of generation within a powerplant has historically been the duty of the powerplant operators. In the early years of operation of Bonneville powerhouse, one operator was assigned and stationed adjacent to each pair of generating units to regulate load and monitor the performance of the units. Other than normal governor control, this was largely a manual operation. McNary was originally designed to be operated in the same way as were Chief Joseph and The Dalles except that four generating units were assigned to a local operator instead of only two. At smaller plants, such as Detroit, Lookout Point, and Albeni Falls, two operators were assigned to perform these functions. With the continued growth of the Federal power system and continued improvement in maintenance and reliability, it became feasible to centralize the operating functions in the powerhouse control room and reduce the number of attended stations on the generator floor. With centralized powerhouse control, a control room operator can start and stop units, synchronize, adjust load and voltage, and monitor the performance of all generating units. Reliability of generating units has now been improved to the degree that the control room is presently the only continuously manned station in Corps of Engineers' main-stem Columbia River plants. A staff

of three operators per shift takes care of all powerplant operation and switching, and also operates navigation facilities, inspects and adjusts fish facilities, and inspects power facilities.

1.2.2 Requirements

The requirements for internal regulation of generation are as follows:

(1) Maintain sufficient generating capacity on line to meet load, voltage, and reserve requirements.

(2) Maintain available standby generating capacity to meet system reserve requirements.

(3) Operate generating units in best efficiency range for conservation of energy during storage control season and for protection of migrating fish.

(4) For plants on LFC to respond adequately to control signals without overshooting or hunting.

1.2.3 Present Methods

(1) The control room operator in Corps of Engineers' major plants is responsible for having a sufficient number of machines on line to meet load requirements, and for maintaining machine operation within established limits. Corps of Engineers' policy is to load machines in the best efficiency range until all available machines are on line. Normally, all machines operating at a given plant which is participating in LFC are on external control. Unit load controllers are used to balance loads among machines.

Typically, Kaplan turbine units have best efficiency in the range of 70 to 90 percent of nameplate ratings. All such units, except those at Bonneville powerhouse, are capable of at least 115 percent of rated load. Therefore, operating at best efficiency provides about 25 percent on-line reserve capacity to handle load changes. System requirements under abnormal conditions may require certain plants to operate without reserve requirements and other plants below best efficiency. Operators manually adjust the set-point of voltage regulators to maintain the voltage schedule at the switchyard and to equalize reactive loading on machines. Conflicts between efficiency requirements and voltage requirements occur fairly frequently during the light load hours of the early morning. For example, if the generation required from The dalles goes down to 400 MW, only six generators would be used to efficiently supply this generation. With only six generators on the line, under-excited reactive available from this plant to control transmission voltage would be only about 210 MVAR. Presently, reactive needed to hold the 230 KV bus voltage down to scheduled voltage at The Dalles during the light load hours frequently exceeds 350 MVAR. Additional reactive capacity can be obtained by putting more machines on the line, but this results in inefficient operation and may be detrimental to downstream fish migration. A decision therefore must be made, based upon the needs of the moment, to sacrifice either efficiency or voltage control. For the small plants which do not participate in LFC, the requirements for load

and voltage control are met in a simple straightforward way. Generation is scheduled by hours at least one day in advance, based on the amount of water expected to be available and the desired load shape. Voltage schedules are published in advance and repeat on a weekly cycle. Powerhouse operators adjust generation and voltage to meet these schedules. The two plants with considerable reactive capability, Detroit and Lookout Point, are operated as synchronous condensers to maintain transmission voltage on schedule even when they are not generating power. The energy losses associated with this mode of operation are apparently assumed a reasonable price for the voltage control obtained.

(2) Corps of Engineers' policy is to maintain maximum availability of generating units for service. Units not in service or not out of service for a specific maintenance job are in "standby" status and are available to start immediately. When maintenance work is completed on a unit out of service, the unit is returned to "standby" status or placed in service if needed.

(3) As noted in (1) above, Corps of Engineers' policy is to operate machines in the best efficiency range until all available machines are on-line. Control room operators are supplied with tables showing number of machines needed for best efficiency for the entire range of plant load and head. They are also furnished instructions for maintaining plant operations within any other required limits. For example, at the plants on the Lower Columbia and Lower Snake Rivers, the needs of migratory fish constitute an

additional constraint on plant operation. Tests have shown that mortality of fingerlings passing through the turbines is reduced considerably when turbines are operated at flows equal to or greater than that required for best efficiency. For this reason, generating units in the Lower Columbia and Snake plants are not operated at loads below best efficiency from about April through October of each year.

(4) Response of load-frequency control systems is checked periodically. BPA technicians in the load dispatch office and CE technicians cooperatively make these tests. CE technicians also test and adjust response rates on individual machines to balance response of all machines in the plant.

1.2.4 Future Methods

(1) The John Day plant now under construction and the plant expansions now being planned for The Dalles, Chief Joseph and Bonneville will include local control computers which will perform some of the internal regulation functions now being performed by operators or present LFC equipment. Jobs assigned to the computers will include adjusting unit generation to meet LFC requirements, balancing loads among units, adjusting voltage to meet schedules and balancing reactive among units. In addition, the computers will automatically monitor plant operation to insure it is within established limits. Operation outside of limits will only be possible through manual intervention by the operator. Under present plans, starting or stopping units to maintain

operation in the best efficiency range will still be performed by the control room operator. The control computers will have expansion capability to perform these functions if and when it is found desirable and economically justified.

(2) The Corps' present plans are to provide all the above functions for Ice Harbor and the other Lower Snake River plants now being constructed from a control computer now installed at McNary. This operation is discussed fully in Section 2. The McNary computer may also eventually perform these functions for the McNary plant.

1.2.5 Summary and Conclusions

Internal regulation of generation to meet system requirements has always been the responsibility of the plant operating staff who are accountable for plant integrity. This function has evolved to a highly centralized one at the Columbia River plants with full automation capability if and when found necessary and economically justified. Full automatic computer control is presently being implemented on the Lower Snake River plants. The established internal procedures for efficient operation normally provide substantial spinning reserve and maximum possible standby capacity at major plants. However, external scheduling may produce conflicts with the internal procedures. Future plans appear to provide the capability for adapting to any future needs.

April 29, 1969

EMERGENCY DROPPING OF GENERATION AND LOADS

1.3 Emergency Dropping of Generation and Loads

1.3.1 Introduction and Background

Automatic reduction of powerhouse generation and customer loads for protection of the transmission system has been an operating practice for many years. Most of these protective schemes are designed to avoid overloading certain transmission lines when other lines have relayed open automatically, due to faults. The development of the Extra High Voltage (500 kv) grid and the California Interties have added a requirement for temporary dropping of generation to protect against large power swings in the system. Several alternative methods of providing this protection are currently being studied.

Customer load dropping is closely related to generator dropping and is briefly summarized in this report.

When certain areas are heavily loaded, and a fault occurs on one of the transmission lines, specific loads are dropped to prevent cascading outages and blackouts.

When system breakups occur and isolated portions of the system have insufficient generation and low frequency, certain loads are dropped to prevent additional outages and to assist the restoration of normal conditions.

1.3.2 Requirements

Requirements for all of these schemes include:

1. Positive operation for protection of the system.
2. Reliable protection against incorrect or improper operation.
3. Procedures for safe, properly synchronized restoration of normal service as soon as conditions permit.

1.3.3 Existing Methods

NOTE: Details of these schemes are subject to change. There is a continuing process of improvement and expansion.

1.3.3.1 Chief Joseph Generation Dropping

Faults on the Hanford-Lower Monumental-John Day 500-kv line cause transmission system power swings which endanger the operation of the California Interties. Rapid reduction of generation can minimize these swings, and the generating units can be restored to normal service immediately.

Computer studies have shown that Chief Joseph is an effective and reasonable place to drop generation for this scheme. When a fault occurs, powerhouse lines No. 2 and 4 open, and the eight generating unit breakers also open. Standing orders call for immediate manual closing at the switchyard, followed by re-synchronizing at the powerhouse.

The relay scheme is taken out of service whenever the Hanford line is open by prearranged outage, or if a portion of the protected line is still open after a relay operation. The scheme is also disabled if there is a reactor scram at the Hanford thermo-nuclear generating station, because that event results in a requirement for additional, not lessened, hydro generation in the area.

1.3.3.2 Boundary Generation Dropping

Boundary, a 650-mw plant on the Pend Oreille River, is owned by Seattle City Light and is regulated by BPA. Faults on either of the Bell-Boundary 230-kv lines (from Spokane to the plant) automatically drop one to three units at Boundary, depending on the pre-fault line loading and the number of units in service. Restoration of normal service is at BPA dispatchers' direction.

1.3.3.3 McNary Generation Dropping

The generation dropping scheme at McNary is not for protection against system power swings, as at Chief Joseph. Rather, it protects against overloading the transmission lines from McNary when one of them is faulted. The protective scheme is in service whenever the combined loading on the McNary-Ross 345-kv line and the McNary-Big Eddy 230-kv line exceeds a preset limit. Under this condition a fault on the Ross line automatically drops the Powerhouse Line No. 5 and its four unit breakers, and a fault on the Big Eddy line or either of the McNary-Santiam 230-kv lines will automatically drop Powerhouse Line No. 2 and its two unit breakers. Resynchronizing and restoration to normal service is at BPA dispatchers' direction.

1.3.3.4 Logic Load Dropping

BPA operates a number of automatic schemes which protect the system by dropping customers' loads to protect large load centers whenever the area loads are heavy, and faults occur in the transmission lines feeding the area. Because these logic-operated

relay schemes are only indirectly related to powerhouse control, only very brief descriptions are included here.

Loads in the Puget Sound area are protected by dropping aluminum-reduction loads when heavy area loads are accompanied by transmountain line faults. Similarly, aluminum potline loads at Spokane are dropped for loss of any of the power lines from Grand Coulee.

In the Bellingham area, protection against complex conditions of line loads and faults is provided by dropping potlines.

The Conkelley load-dropping scheme drops some potlines to protect against loss of the entire Anaconda Aluminum plant when the lines from Hot Springs and Noxon are open, and when generation at Hungry Horse is inadequate to carry the load.

In the Portland area, aluminum potline loads at any or all of three locations can be dropped by combinations of loads, lines in service, and lines faulted.

Most of these protective schemes remain deenergized except when area load conditions indicate that they should be placed in service. Restoration of normal conditions is by BPA dispatchers' direction.

1.3.3.5 Underfrequency Load Shedding

A cooperative program for shedding loads when frequency drops to low values has been in existence in the Northwest Power Pool for many years. This program is designed to help restore normal service after a serious disturbance. The frequencies for

load-shedding are not experienced in the interconnected system, but only in portions of the system which have become isolated. Automatic load-shedding occurs at from 57.0 to 59.55H_z with additional, dispatcher-directed load-shedding below 57H_z. Restoration of normal conditions is by dispatchers' direction.

1.3.4 Future Developments

The number and scope of the generation and load-reduction schemes continually change as the power system changes. In addition, developmental work is in progress or planned for the near future in these areas:

Excitation control and other system damping controls, to supplement or perhaps replace those generation-reduction schemes whose purpose is the control of transient swings.

Pattern recognition techniques to determine the need for generation and load reduction with less need for telemetered data and/or greater protection against false or unnecessary tripping.

1.3.5 Conclusions

Generation and load-dropping schemes enable safe operation of the power system without expensive overbuilding of transmission facilities. As the system and its control develop, these schemes will also develop, to reduce the possibility of misoperation or failure to operate, and to provide more nearly optimum amounts and locations for the power to be tripped.

May 13, 1969

1.4 Providing System Damping

1.4.1 Introduction and Background

As it has expanded, the primarily hydroelectric power generating system in the Northwest has historically experienced periods of oscillatory behavior due to insufficient system damping. This was evidenced by frequency deviations around 60 hertz occasionally building up in a random fashion. These oscillations produced corresponding power and voltage oscillations in the transmission network which severely limited effective use of tie line capabilities in many cases. Such behavior was initially of low frequency (3-5 cpm) and was attributed to improper adjustments of turbine governors. Proper individual compensation of this equipment provided relief for some time. However, as interconnections grew, inherent oscillation frequencies increased to about 6 cpm and periods of build-up reappeared. By utilizing special derivative controls on selected turbine governors, these problems were again temporarily suppressed. With subsequent completion of ties to the Southwest (500 kv), natural oscillation frequencies further increased to about 12 cpm and governor control became ineffective. At about this same time, large scale digital computer stability studies of the proposed California intertie system were also indicating a lack of sufficient system damping. This generated investigation of supplemental controls for plants with continuously

acting (no deadband) excitation systems and has led to development of appropriate hardware. Application is presently being implemented at both new and existing generating stations.

1.4.2 Requirements

The requirements for providing system damping from generating stations are as follows:

(1) Because of the inherent destabilizing effect of water inertia in a hydroelectric plant and its interaction with the mechanical characteristics of the turbines and generators, governor systems must be carefully adjusted. This is necessary to provide adequate response to speed changes and load-frequency control without contributing to system hunting.

(2) High-gain continuously acting voltage regulating systems employing amplidynes, magamps, or silicon-controlled rectifiers (SCR's) must also be properly adjusted to prevent them from providing abnormal amounts of negative system damping.

(3) Such excitation systems at major plants and strategic locations should be provided with supplementary control equipment to generate positive system damping under both normal and transient disturbance conditions. This equipment is designed to produce changes in generator magnetic flux in phase with fluctuations in machine speed or frequency thereby promoting decay of such oscillations.

1.4.3 Present Methods

(1) A maintenance procedure has been established for checking and adjusting governors at each generating station. This

procedure includes setting the governor dashpots so as to insure stable operation when on isolated load while still allowing optimum response to system frequency changes and load-frequency control system signals.

(2) Voltage regulating systems are initially adjusted by the manufacturer to factory specifications. This normally provides fairly stable operation while still producing reasonable response to system voltage errors.

(3) Prototype supplementary excitation control equipment is presently installed at The Dalles, Chief Joseph, and John Day powerhouses. This equipment consists of a single device at each plant connected to a number of excitation systems which have been adjusted to act as a team. The equipment is basically composed of a frequency transducer to obtain a suitable signal and a series of operational amplifier stages to provide proper phase compensation. John Day generator 7 also presently has an experimental high speed SCR excitation system installed for evaluation purposes. It includes supplementary signal equipment.

1.4.4 Future Developments

(1) It is anticipated that a routine maintenance program will be established at powerhouses throughout the region to insure uniform adjustment of continuously acting excitation systems. This will be similar to that now used for turbine governors.

(2) All new major generators are being procured equipped with individual supplementary control devices for system damping.

Additional devices are planned at other existing plants as feasible, practicable, and found desirable.

1.4.5 Summary and Conclusions

The present state of the art indicates that system damping can most effectively be obtained and augmented through local controls at powerhouses. Toward this objective, maintenance procedures have been established for governors and are being developed for excitation system adjustments. In addition, supplemental controls are being added to appropriate excitation systems. At this time, there appears no need for real-time interchange of information between the Corps and BPA for this particular purpose.

May 29, 1969

VOLTAGE CONTROL

1.5 Voltage Control

1.5.1 Introduction

System voltage is one of the critical parameters in the continuous planning and operation of the electric power system. Voltage control equipment consists of transformer taps, shunt capacitors, shunt reactors, and generator and synchronous condenser excitation systems.

1.5.2 Present Voltage Scheduling

Voltage schedules are established for powerhouses and for a number of substations. These schedules are derived by BPA, USCE, USBR, and the NWPP utilities to meet customer needs and to assure equipment safety. They attempt to minimize transmission losses and make effective use of reactive sources. The schedules are based on A-C load flow studies. Voltage schedules are established for each part of the day, repeating on a weekly cycle. The schedules are changed seasonally, or oftener if required. Schedule changes are communicated verbally to the powerhouses by the BPA dispatcher.

1.5.3 Present Voltage Control

(1) Within equipment reactive capabilities, powerhouse operators manually adjust the generator voltage regulators to establish adjacent transmission system voltages to conform to the schedule. Voltage-sensitive relays at many substations

automatically switch capacitors or change transformer taps, to keep the station on schedule or within the approved tolerance.

(2) During abnormal operating conditions, deviations from schedule are allowed, to provide maximum transmission capability. For extended abnormal conditions, new system voltage schedules and operating conditions are determined.

1.5.4 Present Input Requirements

At present, schedules and schedule change information are transmitted by telephone from the system control center to the powerhouses. Total MVAR of most plants is telemetered back to the System Control Center as information to the dispatchers and displayed on recorders.

1.5.5 Future Voltage Scheduling

BPA has recently developed an improved power flow solution which is capable of producing better voltage schedules by a computer simulation technique. These "better" schedules will minimize transmission losses and effectively utilize reactive sources. The program will utilize real-time loads and scheduled loads, transmission system status, and eventually weather conditions and other factors which influence the solution. By making frequent recomputations, the program should minimize violations of voltage limits. As at present, the new "better" voltage schedules will be subject to equipment operating limits and the constraints agreed upon by the customers, the other utilities, and the three governmental agencies. Although the feasibility of the program

has been demonstrated, implementation will require development of a load predictor, improved power system models and software programs.

1.5.6 Future Voltage Control

(1) A coordinated voltage schedule will be telemetered to the powerhouses from the system control center on a periodic basis with additional information during abnormal operating conditions. The plant operator will use these signals to adjust the voltage regulators within the reactive capabilities of the generators. In those powerhouses which have internal computer control, the adjustment will be automatic as often as required.

(2) Substation voltage control devices will be adjusted automatically to maintain the schedules and thereby effectively utilize reactive sources on an area or system-wide basis.

1.5.7 Future Input Requirements

(1) Inputs to the real-time voltage scheduling program at the system control center will include hourly actual loads and schedules, system status as it changes, and eventually weather and other load-prediction information. Feedback information required may include plant total MVAR's from the powerhouses and voltages from adjacent switchyards.

(2) At the powerhouses and substations, the normal update time for voltage schedules will be one hour. A special interrupt signal may be required to provide faster updating when required or to provide voltage control support during system emergencies.

1.5.8 Conclusions

Present voltage scheduling and control methods are reasonably adequate and present no data-transmission or control problems. The future optimum scheduling and automatic control of voltages are expected to:

(1) Minimize violations of voltage limits.

(2) Reduce transmission system losses.

(3) Reduce operators' workload.

(4) Contribute to power system reliability during abnormal or emergency conditions.

(5) Minimize wear on control equipment by eliminating improper and unnecessary voltage adjustments.

Future input data requirements at the system control center include hourly load and load-prediction data and powerhouse-transmission system feedback information. Input at the powerhouses will consist of voltage schedules, updated every hour or as required by special conditions.

July 28, 1969

Exhibit No. 6 to
Attachment No. 3 to Exhibit B of
Contract No. 14-03-19250

PROBLEMS OF GROUP CONTROL OF POWERHOUSES

2.0 Problems of Group Control of Powerhouses

Efficient operation of the Northwest Federal power system requires that operation of the various resources available to the system be coordinated through a central entity which can monitor and control them in response to the dynamic state of power loads, natural streamflows, reservoir storage, and transmission line loadings as appropriate. The real-time operation of the large Federal Columbia River Power System requires continuous monitoring and frequent adjustment of prescribed generation and anticipated schedules to compensate for these factors and for nonpower contingencies.

Interrelations between interconnected power systems brought about by power sales and exchange contracts and the multiple ownership of hydraulically coupled hydroelectric plants on the same river system complicate the resource scheduling process. These complications presently introduce an "iterative" loop in the scheduling process which is handled by voice communication between the power scheduling personnel of the various systems. This procedure slows down the scheduling process which, in times of critical power supply, requires so much time that schedules are often based on very rough estimates. This, in turn, is reflected in individual plant schedules which, more often than not, results in an imbalance of pondage between plants which

severely limits subsequent peaking capability of the hydro projects. It has been the dispatchers' job to try and keep the ponds in better balance either by adjusting the plant participation schedules on the controller or by voice communication to the various plants not on load-frequency control.

This procedure can be improved by making use of real-time computers to automatically adjust the schedules and allocate generation. Performance of this operation in an "optimal" manner is a tremendously complicated mathematical as well as physical problem although its solution is considered only a matter of time and experience. As various approaches are tried, it has become a point of question between the Corps and BPA as to whether powerhouses must be individually controlled by the central controller. The Corps contends that, in certain cases where there is a closed relationship between contiguous plants, group central control is not only feasible but desirable if properly done and coordinated. Such a situation is believed to exist where a logical group of closely interdependent plants are under common control from a single process computer for economy of capital and operating expenses. In this case, the local computer would perform instantaneous allocation of loading between its group of plants in accordance with a single total generation deviation signal and schedule from the system control center. This would reduce the loading of the central controller and its communication linkages to form a master-satellite

arrangement. The Corps believes that this could allow more efficient use of control facilities and more direct response to changing local conditions. Alternately, BPA contends that overall operation of the total system would be enhanced if the loading of each major plant was controlled individually from a common control center. The BPA position is strongly influenced by the severe time deadlines in the power scheduling process made necessary by the "voice loops" required to coordinate the mid-Columbia multiple ownership powerplants. BPA believes this should be avoided in setting up procedures for scheduling and controlling the Federal plants.

2.1 Lower Snake

2.1.1 Problem

The Lower Snake River plants are an excellent example of the above "group control" question. Since the four plants involved (Lower Granite, Little Goose, Lower Monumental, and Ice Harbor) are adjacent and similar, the Corps many years ago adopted a plan of common remote operation from the existing McNary powerplant. This was principally because of staffing economics. To take advantage of the common control facilities, a process computer was also installed to normally automatically operate this closed system. The functions of the computer included load control operation wherein a single signal and load schedule was to be used from the LDO and subdispatched by the computer to the four plants. Construction and programing have proceeded on this

basis, and the Lower Snake River computer control system provides an excellent opportunity to test this concept and provide guidance for future work. It should be noted that "scheduling" per se is not included in the McNary computer but only dispatching in accord with actual conditions to correct for changes from forecasted flows and loads. Such operation should eliminate the present inefficient "voice loop" and automatically maintain pool balances and operation limits.

2.1.2 Recommendations

To provide a factual basis for determining if the "group control" concept has merit and will actually provide an improved type of operation, it is recommended that BPA and the Corps take the following action with respect to the forthcoming placing of Snake River projects on control from McNary:

(1) Generation schedule and inflow forecasts for individual Lower Snake River plants will be developed by the BPA Power Scheduling Section after consultation with the Corps Reservoir Control Center.

(2) The total generation schedule and inflow forecast for the Lower Snake System will be transmitted to McNary as soon as possible after 1800 each day preceding the schedule with updating as may be developed subsequently.

(3) The McNary computer will allocate generation between the plants in the most efficient manner possible in accordance with:

(a) The single instantaneous load control deviation signal from the LDO.

(b) The schedule of total generation including any updating.

(c) Operational limits.

(4) The McNary computer programing will proceed to place the Snake River plants on control from the BPA System Control Center by December 31, 1970.

(5) The computer programing will be subsequently developed to include:

(a) Provisions for action when sustained deviations from the schedule are in excess of plus or minus approximately 5 percent. This will consist of:

1. Computation and printout of predicted pool levels at end of scheduled period resulting from sustained deviation operation.

2. Printout to notify operator if any operating constraints are endangered. This will allow the plant operator and dispatcher to make adjustments to the schedule if necessary.

(b) On demand or time controlled printout of available generation resources including available KWH's for remainder of period and capacity (peaking) availability for predetermined time period.

(c) Computation of spinning reserve available on the plants which can be picked up by controller action. This information should be telemetered to the BPA load dispatch office to be added to the main-stem data in order to assure sufficient operating reserve.

This operation will provide some actual experience. After a suitable test period, the concept should then be reexamined and a decision made on whether it should be modified or discontinued and a procedure initiated similar to BPA's proposal.

2.2 Columbia River and Other

The possibility of "group control" of powerhouses at other locations is considered irrelevant at the present time pending experience with the "Snake River" system as described above. The Task Force, therefore, does not propose to expend any effort at this time in discussing such speculative items.

November 9, 1970

Exhibit No. 7 to
Attachment No. 3 to Exhibit B of
Contract No. 14-03-19250

PROBLEMS OF CENTRALIZED CONTROL OF RESERVOIR POWERHOUSES

3.0 Problems of Centralized Control of Reservoir Powerhouses

Large powerplants constructed in conjunction with storage reservoirs present different problems in respect to coordination of operation with the power system than main stem run-of-river plants. This section is intended to explore this different relationship and determine necessary interface facilities.

3.1 Need for Centralized Control of Generation at Reservoir Powerhouses

The need for centralized control of generation, as distinguished from scheduling of generation, is to continually match generation to load including scheduled interchange with other utilities. To effectively perform this function, an adequate amount of generation should be on centralized control at all times to be capable of responding to load changes in a stable manner. Response rates of individual controlled plants should not be set so high as to induce excessive overshoot or instability in the power system. Moreover, since maintenance outages and river flows approaching or exceeding a plant's hydraulic capacity will, at times, make certain plants incapable of performing this function, an adequate reserve of generating capacity capable of performing the load-frequency control function should be available.

3.1.1 The Federal system needs sufficient generation on centralized control to cover short-term operating requirements such as normal

load fluctuations, changes in schedules with other utilities, spinning reserve to cover loss of generation, or loss of lines or loads.

3.1.2 The NAPSIC (North American Power System Interconnection Committee) Operating Manual defines the spinning reserve requirement in Operating Guide No. 10 as follows:

> "The spinning reserve capacity available to any coordinated area shall be sufficient to meet its largest instantaneous hazard without unduly jeopardizing other coordinated areas' reliability of operation. Since no unit can respond instantaneously to provide its full reserve capability, even though it is on line and spinning, it is essential that each coordinated area determine the rate of response of its units and the manner in which its reserve is distributed throughout the area to assure that its spinning reserve capacity is fully effective."

3.1.3 At the present time, the Federal system occasionally operates with less than 1000 mw of unloaded continuous capacity at Bonneville, The Dalles, John Day, McNary, Chief Joseph, Grand Coulee, and the two existing Lower Snake plants on centralized control. This amounts to about 10 percent of the Federal generation. Additional generation now planned or under construction at Grand Coulee, Chief Joseph, John Day, The Dalles, Bonneville, and the Lower Snake plants will also be on centralized control.

3.1.4 From the power system standpoint, generation responding to centralized load-frequency control should ideally be limited in its response only by the physical limitations of the equipment. However, other multipurpose constraints are imposed by Federal operating agencies on the projects which restrict their ability to automatically follow variations in power demands. Because of these constraints, it is necessary for the Federal system to maintain a higher level of spinning reserve than would be necessary for a hydro system without such multipurpose constraints.

3.1.5 Another factor which influences the need for a relatively high level of spinning reserve is the large area covered by the Federal generation and transmission system. There is a large diversity in streamflow throughout the Columbia River Power System. Hydro plants on the eastern edge of the system, such as Hungry Horse, Libby, and Dworshak, will generally be operating at low energy outputs during the refill-hold period of the year. During this period power flow is toward the east. In the event of a loss of transmission capacity into the area, hydro plants in the area should be available to automatically respond and pick up load.

3.2 Problems of Centralized Control of Generation at Reservoir Powerhouses

A primary problem of centralized generation control at many powerhouses is the limitation on rate of change of water released. This problem is accentuated at the two reservoir powerhouses being considered, namely Dworshak and Libby, because the limits are very stringent. However, short-term limitations, applicable

only during specified conditions, could be defined and utilized. Other problems involve the small generating capacity of the plants and the relative difficulty of keeping units within operating range if centralized control is applied. In some cases this means that the availability of the plant for centralized control is limited to certain portions of the year.

3.2.1 Dworshak

The basic problem using Dworshak units on centralized control is the relatively limited usable operating range on each unit. The characteristics of high head Francis turbines are such that they operate smoothly and efficiently at full load and above, but not at partial loads. Based on preliminary information available at this time, we expect the usable operating ranges for the Dworshak units will be as follows:

	Pool Elevations		
	1600	1535	1450
Units 1 or 2	75 - 103 MW	70 - 103 MW	55 - 77 MW
Units 1 and 2	150 - 206 MW	140 - 206 MW	110 - 154 MW
Unit 3	190 - 266 MW	170 - 250 MW	140 - 190 MW
1 or 2 plus 3	265 - 369 MW	240 - 353 MW	195 - 267 MW
1 + 2 + 3	340 - 472 MW	310 - 456 MW	250 - 344 MW

From this tabulation, it is apparent that the only operating range which would be usable for load control participation is the range in which Unit 3 and at least one additional unit are operating. This condition will occur only during a portion of the year. Therefore, it is apparent that the Dworshak plant is not suitable

for participation in continuous year-round load control. However, other possible schemes could be used to meet the objective of adding spinning reserve to the system, so as to pick up available unloaded generation automatically in response to system abnormal conditions. Within the limits on rate of change of tailwater at least one and sometimes two units could be started automatically in response to a requirement signal and be brought up to full load. The duration of this full-load operation should be limited, but it would be long enough to cover the system needs as defined by the dispatcher, up to a preset time limitation. The requirement signal could be developed at McNary--possibly from an LFC deviation signal greater than 50 MW--or could be transmitted from BPA dispatch office, by specific action of the dispatcher.

3.2.2 Libby

The primary problem with including Libby on centralized generation control is the limitation on rate of change of water released. At present the limits in rate of change of discharge are established as:

- Summer 1 ft. (60 mw) per hour
  4 ft. (240 mw) per day
- Winter 2 ft. (120 mw) per hour
  6 ft. (360 mw) per day

These very stringent limits on rate of change of generation at Libby will restrict the effectiveness of the plant insofar as

load-frequency control of generation is concerned. As at Dworshak, however, special constraints for short-term fluctuations (substantially less than one hour) could be defined and used.

3.3 Summary

The objective in the daily operation of reservoir projects such as Libby and Dworshak is threefold:

(1) Obtaining a predetermined average daily discharge;

(2) Shaping the available energy to help meet peak loads at times when peaking help is needed; and

(3) Picking up the available unloaded generation automatically in response to specified system conditions.

It would not be necessary to have Libby and Dworshak on centralized control as far as items (1) and (2) are concerned, but it is necessary in order to achieve item (3).

3.4 Recommendation

The application of normal load-frequency control to Libby and Dworshak is not recommended because of the limitations and difficulties involved. Instead, the following is our recommendation:

(1) Establish short-term limits for load variation;

(2) Establish automatic or semi-automatic circuitry to utilize the reserves at these plants as required and within the limitations.

February 9, 1970

AUTHENTICATED COPY

Attachment No. 4 to Exhibit B of
Contract No. 14-03-19250
Effective Date: November 18, 1970

OPERATING ARRANGEMENT
(Dispatcher-Operator Working Relations)

SUBJECT: Principles and Procedures for Maintaining Effective Working Relations between Power System Dispatchers and Power Project Operators

1. This Operating Arrangement is made pursuant to paragraph 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer.

2. General. The North Pacific Division (NPD) Operations Division and the Bonneville Power Administration (BPA) Branch of System Operations have agreed upon certain principles and procedures for maintaining effective working relations between power system dispatchers and power project operators. These principles and procedures, as set forth below, are applicable to the 1970-71 operating year. They will be reviewed at the end of each operating year and extended or revised as appropriate.

3. Principles. The BPA Branch of System Operations and the NPD Operations Division are in agreement on the following principles:

A. BPA power dispatchers have the responsibility for meeting power system loads and for maintaining reliable operation of the power transmission system.

B. NPD power project operators have the responsibility for supplying the generation required by schedule and participation in load-frequency control, from their respective plants within the constraints imposed by nonpower considerations and within the limitations of powerplant equipment.

4. Procedures. The problem areas of dispatcher-operator relationships basically fall into one of the following categories:

Reservoir Regulation

Equipment Limitations

Voltage Control

Load-Frequency Control

Navigation and Fish Passage

A. The power project operators and system power dispatchers will observe the following procedures when problems arise:

(1) Thoroughly discuss the problem, examine alternatives, and attempt to identify the best overall solution.

(2) If necessary to violate any operating limits, the power project operator or system dispatcher shall report the problem and action taken through his appropriate command channels.

B. In the event of an emergency, either in the powerplant or on the transmission system:

(1) Each party (powerplant operator and system power dispatcher) will do all within his power to assist the party in trouble. This may include temporary suspension of any hydraulic or electrical limitations in effect at the time.

(2) If it is necessary to violate any hydraulic or electrical limitations, the powerplant operators or system power dispatchers shall report through their appropriate command channels.

C. NPD and BPA will mutually schedule periodic visits of dispatchers to powerplants and project operators to the BPA System Control Center. These visits will provide sufficient time for in-depth exploration of problem areas and full exchange of views for maintaining an atmosphere of mutual trust and understanding.

APPROVED /S/ H. R. RICHMOND
Administrator
Bonneville Power Administration

APPROVED /S/ ROY S. KELLEY
Division Engineer
North Pacific Division

(AUTHENTICATED COPY)

Attachment No. 5 to Exhibit B of
Contract No. 14-03-19250
Effective Date: December 1, 1970

OPERATING ARRANGEMENT
(Data Acquisition, Engineering, and Planning)

SUBJECT: Principles and Procedures Relating to Powerhouse Data Acquisition, Engineering, and Planning Including Interchange of Data with the Power System Control Center

1. This Operating Arrangement is made pursuant to paragraph 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer.

2. The BPA-NPD Coordination Task Force No. 3 documented information on present data and control characteristics, procedures therefor, and deficiencies. Other documentation was produced on general design objectives, criteria for improved data and control communications, and data system configurations. Copies of this documentation are attached hereto as Exhibits 1 and 2. Included in this Operating Arrangement are priorities and implementation schedules for the required data systems.

3. Principles. Methods for planning, budgeting, scheduling, designing, and constructing these facilities will be developed cooperatively in accordance with the separate requirements of the NPD and BPA pursuant to paragraph 10 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer.

4. Procedures.

A. It has been agreed that data representing power project operation originating at NPD facilities is needed by BPA for system operation. In accordance with the basic Memorandum of Understanding

and Attachments 1, 2, and 3, the present definition of these data are listed below (single asterisk, *, indicates data between the Reservoir Control Center and the System Control Center; double asterisk, **, indicates data between the project and the System Control Center; triple asterisk, ***, indicates data between substation and project):

(1)	Normal operating limits	*
(2)	Special operating limits	*
(3)	Modifications of plant loading schedules	*
(4)	Number of units on line	**
(5)	Number of units on LFC control	**
(6)	Number of units off line (available)	**
(7)	Capacity of units on LFC control plus load of units on line but not on LFC	**
(8)	Reserve capacity of units on line but not LFC	**
(9)	Capacity of units available but not on line	**
(10)	Forebay and tailrace water levels	**
(11)	Total project generation in kwh	**
(12)	Discharge	**
(13)	Project total generation in MW	**
(14)	Project total generation in mvar	**
(15)	Hydrometeorological data	*

BPA and NPD will establish automatic data and control (bi-directional) communications between the Power System Control Center and key power projects important to load regulation and capacity resources of the region. Projects included in this category which will require interchange of all listed data (paragraph 4.A and 4.B) are as follows:

Bonneville
The Dalles
John Day
McNary
Lower Snake
    Ice Harbor
    Lower Monumental
    Lower Granite
    Little Goose
Chief Joseph

The amount of listed data exchanged for other projects depends on the relationship of the project to the centrally coordinated operation of the system. Projects in this category are as follows:

Dworshak
Libby
Detroit-Big Cliff
Lookout Point-Dexter
Foster-Green Peter
Hills Creek
Cougar
Albeni Falls

B. It has been agreed that data representing power system operation originating at BPA facilities is needed by NPD for project or multiple project operation. In accordance with the basic Memorandum of Understanding and Attachments 1, 2, and 3, the present definition of these data are listed below (refer to definitions under 4A; also triple asterisk, ***, indicates data from substations to projects):

(1) Preliminary system loading information including non-NPD projects and Intertie *

(2) Changes in B(1) *

(3) Complete input and output of plant schedule computer runs *

(4) NPD projects schedule changes *

(5) Lower Snake total generation schedule **

(6) Lower Snake River inflow forecast **

(7) Generation dropping signals ***

(8) Project voltage schedules **

(9) Reserve capacity loading signal **

(10) Changes in project schedule breakpoints *

(11) Project load frequency control deviation signal (MW) **

(12) Hydrometeorological data *

BPA and NPD will establish automatic data exchange (bi-directional) communication between the Power System Control Center and the Reservoir Control Center. All of the data items in paragraphs 4.A and 4.B marked with a single asterisk * may not be included in this data exchange depending on acceptability of alternative means such as voice communication.

C. It has been agreed that the BPA-Corps Coordinating Group should consider other data requirements not specifically defined or agreed to by Attachments to Exhibit B of Contract No. 14-03-19250. A partial list of such data follows:

(1) Data originating at NPD projects for transmitting to BPA facilities:

(a) Abnormal limit alarms

(b) Project off load frequency control

(c) Load frequency control opposition

(d) Project spill

(e) Generation overload operation

(f) Generation extra overload operation

(2) Data originating at BPA facilities for transmission to NPD projects:

(a) Desired project generation level

(b) Changes to voltage schedules (special conditions)

(c) Changes to daily load schedule

D. The NPD and BPA recognize that data needs as established by past practices are changing and they will continue to develop plans and programs for implementing computerized data acquisition and control systems for improving power project and power system operation.

E. The BPA Branch of Power System Control and the NPD Hydroelectric Design Branch are in agreement that the following procedure will be followed to maintain liaison between the two Branches.

(1) Policy guidance will be established through the BPA-NPD Coordination Group.

(2) The two Branches will:

(a) Expedite the energization of the interim data acquisition facilities now on order to comply with information requirements defined in Attachment 2 to Exhibit B of Contract No. 14-03-19250, "Operating Arrangement" (Spinning Reserves and other Reserve Capabilities).

(b) Proceed with definitive planning and engineering for implementation of the complete automatic data systems (paragraph 4.A and 4.B above).

(c) Exchange information and discuss plans for future control functions and methods of operation as required, to develop necessary additional data exchange and control systems.

5. System Configuration. To accomplish the stated requirements for data exchange and control, the NPD and BPA agree that the data and control update and response times will not exceed the capability of one full audio channel (bi-directional-full duplex, four-wire characteristics) between each project and the System Control Center, and between the System Control Center and the Reservoir Control Center. Additional studies are planned to determine if a wider bandwidth channel is required between the two control centers.

The basis for this agreement is that the present evaluation indicates that all requirements for data and control rates, with consideration for data volume, will not require more than a 2400 baud data channel between any two points of the system configuration.

6. Priority and Projected Schedule for Implementation.

A. The interim data acquisition facilities for spinning reserves and other reserve capabilities are under construction and will be energized in early 1971. These interim data channels will be installed between the present BPA Portland System Control Center and the NPD Bonneville project, The Dalles project, John Day project, McNary project, Lower Snake projects (via McNary) and the Chief Joseph project.

B. Planning, design, and construction of bi-directional data and control communications between the BPA Dittmer System Control Center

computers and the NPD Lower Snake projects computer (at McNary), the John Day project computer, The Dalles project computer, and the Portland Reservoir Control Center computer (Custom House) is proceeding. These facilities will be scheduled to be energized by January 1973.

C. Automated data facilities are not scheduled for the NPD Bonneville project and Chief Joseph project before fiscal year 1976. To provide data critical to the coordinated power system operation, the NPD and BPA will plan, design, and construct bi-directional data channels between the BPA Dittmer System Control Center computers and data acquisition terminals at Bonneville and Chief Joseph projects. These facilities will be scheduled to be energized by January 1973.

D. The NPD plans to expand the Lower Snake projects computer (at McNary) to include operating functions for the McNary project. Under this plan bi-directional data and control communications requirements between the BPA Dittmer System Control Center computer and the NPD McNary project will be included in the one circuit to the Lower Snake projects computer. If this is not feasible a separate circuit and data acquisition terminal will be provided at the McNary project as in paragraph C. Under either plan these facilities will be scheduled to be energized by January 1973.

E. The NPD and BPA agree that generation, reserves, and reservoir level data from the Willamette Valley projects will be automatically transmitted directly to the Reservoir Control Center computer. The NPD agrees that these data will be available to BPA via the Reservoir

Control Center to Power System Control Center data link. These systems will be scheduled to be energized between 1973-75.

F. The Dworshak and Libby Reservoir projects now under construction will have automatic control facilities for utilization of reserve capacity directly from the System Control Center in lieu of LFC equipment. These control circuits together with other data exchanges will be placed in operation in accordance with the power generation schedule for these projects.

G. Additional studies are planned to determine the implementation plan and schedule for data acquisition from the Albeni Falls project.

APPROVED /S/ DONALD PAUL HODEL
Acting Administrator
Bonneville Power Administration

APPROVED /S/ ROY S. KELLEY
Division Engineer
North Pacific Division

Exhibit No. 1 to
Attachment No. 5 to Exhibit B of
Contract No. 14-03-19250

BPA - Corps Coordination Task Force No. 3

Task 1.0 Develop policy for acquisition and transmission of powerhouse data (sub-items 1.1, 1.2, 1.3, and 1.4)

1.1 Classification of Powerhouse Data and Control Information.

Powerhouse Data - Data which has been classified in this report is limited to information of interest external to the powerhouse by the Corps or BPA or other agencies. Powerhouse data includes information to allow control, operating, and scheduling decisions to be made; and may be grouped in six general classifications as follows:

Electrical

Hydraulic

Status

Developed (Computed)

Event or Alarm

Other

1.1.1 Electrical data consists of generator watts, watthours, volts, amperes, vars, excitation voltages and currents, total watts and vars, frequency, load control deviation, and total project watthours.

1.1.2 Hydraulic data includes river and reservoir information necessary for maintaining multipurpose stream operation and for operation

within defined constraints. These data include forebay and tailwater elevations and, where pertinent, upstream and downstream level elevations.

1.1.3 Status data defines the operating condition of project equipment. It includes the following generating unit information:

On load control from power system control center

On load control from powerhouse control room

Out of service

On standby (ready to start)

Motoring

Generation dropping system

Units selected for generation dropping

Other project status information includes spillway gate positions, status of plant auxiliaries, and positions of all major circuit breakers.

1.1.4 Developed data must be computed by either the control room operator or the project computer from electrical, hydraulic, or status data. Date developed consists of the following:

Reservoir inflow

Reservoir outflow

Power discharge

Spillway discharge

Other discharges (fishways, lockages)

Head

Reservoir storage

1.1.5 Event or alarm data is developed by abnormal operations. This information is either displayed on flashing annunciator windows or printed out in English by the project computer. The primary purpose of this information is to allow the operator to take corrective action. Generator protective relay operations leading to load rejection and shutdown and main power transformer relay operations which result in loss of generation are included along with project auxiliary equipment troubles.

1.1.6 Other Data - The powerhouse control room acts as a collection point for miscellaneous information of interest to several agencies. These data include weather information, number of navigation lockages, fish count, and water quality.

1.2 Present Procedures - The Columbia and Willamette River Basin projects have been constructed over a period of 30 years. The normal evolution of equipment and procedures such as staffing changes and electrical signal conditioning equipment has resulted in a wide range of installation types; however, some general conclusions may be made which apply to all. Table 1 has been prepared to show a summation of reading accuracy for various data. Table 2 lists instrumentation rated by project engineers as exhibiting less than good reliability. Table 3 lists data which is transmitted from the project by duplicate means.

1.2.1 Electrical Data

(1) Generator watts for individual units are displayed on switchboard instruments and on recording wattmeters in all control

rooms. The generator potential transformer and current transformer (PT and CT) circuits are routed to the control room on all projects constructed prior to John Day. Wattmeter and summation circuits are shown in Fig. 1 for projects of this type. Transducers are of the thermal converter type with output in the millivolt range. John Day and Lower Snake River projects starting with Lower Monumental and new units added to existing projects will make use of transducers in the unit switchboards (on the turbine floor) to provide a 0-5 volt d-c signal proportional to watts for control room indication as shown in Fig. 2. Each unit is provided with a single high-level watt transducer which supplies a 0-5 volt d-c signal proportional to watts for the following functions:

Control console wattmeter

Graphic switchboard unit watt recorder

Input to totalizing circuit for plant total watt recorder

Input to totalizing circuit for total watt signal to telemetering transmitter

Input to computer analog to digital converter

In general, the operator is able to read the nondigital read/out wattmeter indication from 2 to 4 percent of the unit rating. The reliability of the instruments is good to excellent.

(2) Generator Watthours are monitored in three different ways. A unit watthour meter is provided for each generator and may

be located on the unit switchboard, or on the control room switchboard. Watthour meters located on the control room switchboard are individually read hourly by the operator and totalized. Totalizing relays or the project computer is used to obtain the total watthour quantity where the watthour meters are located on the unit switchboards. Totalizing is accomplished by impulse contacts driven by the watthour meter registers. The location and manner of totalizing is determined by an engineering study at the time of control system design or when staffing changes are being made. The study takes into account factors such as staffing, availability of PT and CT circuits, and future automation requirements. Automatic totalizing is provided at the following projects:

Chief Joseph

McNary

John Day

Ice Harbor

Lower Monumental

Hills Creek

Detroit

Lookout Point

All other projects rely on the control room operator for the totalized quantity. Individual watthour meters are readable to one megawatthour at most projects.

(3) High-Voltage Bus instrumentation is normally provided by a switchboard indicating instrument in the control room. Reading accuracy varies from project to project and ranges from 0.2 to 10.0 percent. A wide variation exists in circuitry. The following table indicates the sources for bus potential:

Project	Bus KV	Capacitor Potential Device	Potential Transformer	Powerhouse Transformer Bush. P.D.**
Chief Joseph	230		*	
McNary	230		*	
John Day	500			X
The Dalles	230		*	
Bonneville	115/230	X(115 KV)	230 KV*	
Lookout Point	115		X	
Dexter	115	None		
Hills Creek	115	None		
Cougar	115			X
Green Peter	115	None		
Foster	115			X
Albeni Falls	115	X		
Ice Harbor	115		X	
Lower Monumental	500			X
Little Goose	500			X

* 115 KV and 230 KV bus voltmeters are connected to potential sources in the BPA switchyard.

** P.D. = Bushing Potential Device.

(4) Frequency is indicated on a recording frequency meter at major projects, and is also available at all projects on manual synchronizing panels. Reading accuracy varies from 0.02 Hz. to 0.1 Hz. on the recorders. Reliability is considered good to excellent at all projects.

(5) Station Service Watthours - Station service watthour meters are located either on the station service switchboard, station service switchgear, or on a station service control panel located in the control room. This quantity is normally read once each 24-hour period when the meters are located external to the control room. Hourly station service watthour information is transmitted on the CBTT from major projects. This is estimated if the meters are not in the control room or read if the meters are available. Station service watthour reading accuracy varies from 40 KWH to 1000 KWH (least significant digit), and reliability is rated good to excellent by the projects.

(6) Project Total Watts - Project total watts is indicated on a recording wattmeter in the control room at all major projects. The recording wattmeter quantity is developed by summation of the individual unit transducer outputs as shown in Figs. 1 and 2. Reading accuracy is from 5 MW to 20 MW, and is in general a function of the total project capacity. Total project watts can be displayed on a four-digit read/out at McNary for the Lower Snake River projects. Project total

watts for all projects on load control is telemetered to BPA by analog telemetering transmitters. The telemetering quantity is developed by summation of the individual generator transducer outputs on all projects except for the Green Peter-Foster signal. The Green Peter signal is converted to an analog signal by a digital to analog converter at Foster, and summed with the Foster watt transducer output for telemetering to BPA. The total watt quantity for each project is transmitted to BPA as follows:

Albeni Falls	- Telemetered directly to BPA
Chief Joseph	- Telemetered directly to BPA
McNary	- Telemetered directly to BPA
John Day	- Telemetered directly to BPA
The Dalles	- Telemetered directly to BPA
Bonneville	- Telemetered directly to BPA
Lookout Point	- Generation determined at Alvey Sub.
Dexter	- Generation determined at Alvey Sub.
Hills Creek	- Generation determined at Alvey Sub.
Cougar	- Telemetered directly
Foster	- Combined with Green Peter and telemetered
Green Peter	- Combined with Foster and telemetered
Detroit	- Telemetered directly to BPA (includes Big Cliff)

(7) Project Total VARS - This quantity is not displayed in the control room at all projects. It is not a basic quantity for "in plant" control and, in general, has been added to the

control room instrumentation as a part of total VAR telemetering. Reading accuracy is from 1 to 10 MVAR's where displayed. The following projects telemeter total VAR generation to BPA:

Chief Joseph

McNary

The Dalles

John Day

Bonneville

Foster

Detroit

(8) Load Control Deviation - This quantity is recorded on one pen of a two-pen recorder in project control rooms where load frequency control is a project function. The deviation signal can be read from 1 to 5 MW and reliability is rated good to excellent. The signal is telemetered to the projects via the BPA microwave system (with an alternate carrier-microwave backup communication channel). Projects under load frequency control or scheduled for load frequency control are as follows:

Chief Joseph

McNary

The Dalles

John Day

Bonneville

Lower Snake River Projects:

Ice Harbor

Lower Monumental

Little Goose

Lower Granite

(9) Project Total Watthours - Methods of obtaining this quantity were discussed under paragraph 1.2.1 (2) Generator Watthours.

1.2.2 Hydraulic Data

(1) Forebay and Tailwater Levels - Forebay and tailwater elevations are continuously recorded in all project control rooms. Elevation is readable in the range of 0.01 to 0.1 feet. Reliability of water level information varies from poor to excellent. Forebay and tailwater elevations are transmitted by CBTT and are also phoned to BPA.

(2) Project Upstream and Downstream Water Levels - Water levels other than forebay and tailwater elevations are collected and transmitted externally from the following projects:

Albeni Falls	- Upstream level - Hope, Idaho
Cougar	- Upstream level - USGS Gage - Downstream level - USGS Gage
Lookout Point	- Upstream level - 15 miles
Hills Creek	- Upstream - 11 mi., Mid-Fork Willamette - Upstream - 5 mi., Hills Creek - Downstream - 1½ mi. from dam
Dexter	- Downstream - 2 miles from dam
Foster	- Upstream - Cascadia - Downstream - Foster

Upstream and downstream water levels are transmitted both by CBTT and by voice to BPA.

1.2.3 Status Data - Status of generation of Columbia River projects is transmitted via CBTT and voice to BPA hourly. Loss of generation caused by equipment malfunction is reported to the dispatcher by voice at the earliest opportunity; generally within 5 to 10 minutes of the occurrence. No automatic transmission of status exists to either the Portland Office of the Corps of Engineers or to the BPA System Control Center.

(1) On Load Frequency Control from Power System Control Center - This is determined from switch positions in the control room. External transmission of the number of units on load frequency control is by CBTT.

(2) On Load Control from Powerhouse - Status determination by operator from switch positions with total number of units in this status included in CBTT hourly report.

(3) Out of Service - Status information developed by operator based upon clearance procedure or by alarm display in the case of unplanned outages. External transmission is by voice to System Control Center.

(4) On Standby - Status determined by control room operator based upon his knowledge of operating condition of unit. Report of status of total number of units on standby included in hourly CBTT.

(5) Motoring - Status determined by operator from control room instrumentation. Information transmitted by voice to Portland on status.

(6) Spillway Gate Position - The method of obtaining spillway gate position in the control room depends upon the type of spillway gate, the size of the project, and the expected number of spillway gate operations. Spillway gates which are operated by gantry cranes and are of the multiple leaf type do not lend themselves to remote control or position indication. Albeni Falls, McNary, and Bonneville projects all have gates of this type. No remote control or position indication is provided in the Albeni Falls or Bonneville control rooms. Control and position indication is provided at McNary for five pre-selected bays. Complete spillway gate position is provided in the following control rooms:

The Dalles

John Day

Chief Joseph

Ice Harbor

Lower Monumental

Cougar

Foster

Lookout Point

Spillway gate positions are not transmitted from the project. The spillway gate discharge (total) is included in CBTT information.

(7) Switchyard - Powerhouse Line Breaker Positions - Breaker positions of the BPA switchyard breakers associated with

powerhouse lines are normally displayed in the powerhouse control rooms.

1.2.4 Developed Data - Developed data is calculated by the project computer or control room operator from primary data.

(1) Inflow - This is computed from upstream gaging stations (if available) or the discharge of the next project upstream is used. It is transmited by CBTT if computed from upstream gages.

(2) Outflow - This is the total of power discharge, spill discharge, and miscellaneous discharge as calculated by the operator. Hourly values and a 24-hour value are transmitted on the CBTT.

(3) Power Discharge - This value is determined by the project computer or by the operator from watthour generation. This is reported both on the hour and for the 24-hour period on the CBTT.

(4) Spillway Gate Discharge - Either the control room operator or the computer computes spillway discharge from the spillway gate positions. Hourly computations and a 24-hour computation are made and reported on the CBTT

(5) Other Discharge - This miscellaneous discharge is made up of lockage water, fishway discharge, and other discharge that is not included in power or spill. The miscellaneous discharge is included in the total outflow transmitted by CBTT.

(6) Head - The mean daily head is calculated by the operator and transmitted by the CBTT as a daily value. This head is determined by averaging the forebay and tailwater elevations for the 24-hour period.

(7) Storage - Storage is computed by the project computer or operator on a 24-hour basis. It is not transmitted from the project.

1.2.5 Event or Alarm Data - No event or alarm data is now automatically transmitted from the projects.

(1) Emergency Shutdown - Action which results in shutdown of a generator is alarmed by audible alarm and window display in the control room. In addition, the project computer or event recorder prints out in English the events which occur and the time. Voice and CBTT are used to transmit the shutdown information to the System Control Center.

(2) Transformer Lockout - This event is the result of protective relay action and results in the loss of generation. Annunciation, event recording, and transmission of the event information is similar to "shutdown."

(3) Transformer Overheat - This alarm is initiated by temperature relays or temperature monitoring of RTD's in the transformer. The alarm is provided to allow the operator time to take corrective action prior to shutdown by protective relaying.

1.2.6 Other Data

(1) Lockage Count - This count is kept in the project log and reported to interested agencies by mail. The CBTT Usage Bulletin includes a provision for future transmission of this count on a daily basis.

(2) Fish Count - This is now transmitted on an hourly basis by the CBTT.

(3) Wind Direction - Wind direction is included in the daily hydromet message on the CBTT. Reliability of measuring instrumentation is generally rated poor to good by projects. Reading accuracy varies from 10 to 60 degrees.

(4) Wind Velocity - Wind velocity is reported in the daily CBTT hydromet data. Reliability is rated poor to good, and reading accuracy is considered to be from 2 to 10 miles per hour.

(5) Precipitation - Included in daily hydromet data on CBTT from projects. Reading accuracy is 0.01 feet, and reliability is rated good to excellent.

(6) Air Temperature - Reported in daily hydromet data on CBTT. Reading accuracy is plus or minus one degree and reliability is good to excellent.

(7) Humidity - This quantity is logged but not generally included in CBTT data.

(8) Cloud Cover - This is included in CBTT data from Albeni Falls, Lookout Point, and Foster. Cloud cover is reported by mail from McNary, Bonneville, and Detroit.

(9) Water Quality - Water temperature is reported daily by CBTT from Chief Joseph, Bonneville, and Ice Harbor. Turpidity is reported daily by CBTT from Ice Harbor and by mail from McNary, The Dalles, John Day, and Bonneville. Radioactivity and dissolved nitrogen content is reported by mail from The Dalles.

1.3 Determine Deficiencies in Present Procedures - Existing procedures for measuring, displaying, and transmitting data have been designed primarily for manual operation and control of the powerhouse and manual support of dispatching and control of the Federal power system. Deficiencies that may exist should be considered relative to system functions. In this context, consideration should be given to elimination of duplicate transmission of data as listed in Table 3, Paragraph 1.2, and to automatic procedures for transmitting abnormal project or system alarms.

1.3.1 Powerhouse Operation - Local operation and control of powerhouses is supported by metering, recording, status, alarms and/or event recording on unit switchboards or control room panels, and includes the data types and variations described under paragraph 1.1. Specific deficiencies in data requirements vary with each powerhouse under study. Projects being considered for external data transmission improvement should take into account the following factors:

(1) Accuracy

(2) Reliability

(3) Manpower required for manual logging, manual calculations, and manual totalizing

(4) Do powerhouse reading and compatible reading in adjacent switchyard substantially agree?

1.3.1.1 Specific deficiencies in supporting local operation and control of the powerhouse with data on performance, unscheduled changes, and

regulation schedules for the power system for centrally controlled plants:

(1) Updating of powerhouse participation requirements when changed in form of LFC console breakpoint settings or hourly loads

(2) Hourly schedule for Hanford NPR generation

(3) Notification of Hanford NPR shutdown in advance when possible or on occurrence

(4) Hourly schedule of Interchange for Intertie

(5) System disturbance information

(6) Coordination information relative to the operation of Priest Rapids for McNary operator.

for block scheduled plants:

(7) Information relating to major unscheduled deviations of plant load such as may result from (3), (4), or (5) above.

1.3.2 Power System Control

1.3.2.1 Dispatching and control of the power system is supported by powerhouse data in the form of LFC telemetering, CBTT, and voice. Specific deficiencies in these data support of present functions for centrally controlled plants:

(1) LFC analog telemetering is susceptible to degradation due to drift or calibration errors such as an end-to-end error or thermal converter totalizing circuit error. The analog telemetering lacks self-checking capability and the failure of the control signal to the powerhouse (i.e., status such as operation on primary or alternate channel is not available to the central control system).

(2) Columbia Basin teletype system is serviced by manually entered data at the powerhouse. The data may be as much as two hours late. The CBTT system does not provide automatic access to data on a fixed schedule or on-call basis. The data accuracy and format are susceptible to TTY operator errors.

(3) Voice communication is the most frequently used media to report emergency situations. The reporting of emergency change of status or other critical conditions is not adequate because of higher priority responsibilities of operator and dispatcher. The first duty of the operator is to the safety of the powerhouse. Transmission of routine periodic data by voice is burdensome on both operator and dispatcher, and subject to error or misinterpretation.

1.4 Explore Methods of Improving Present Procedures

1.4.1 The NPD and BPA have projected plans for implementation of computerized data acquisition systems for modernizing powerhouse operation and central control and dispatch of the power system, respectively.

1.4.2 Evident in both agency planning efforts are sophisticated digital computer installations, permitting substantial improvement in the exchange of data and support of mutually related responsibilities in coordinated operation and control of the total power system.

1.4.3 It is intended by the NPD and BPA to establish automatic data communication between the Power System Control Center and key powerhouses (those important to load regulation and capacity

resources of the region), and between the Power System Control Center and the Reservoir Control Center. The deficiencies of the present data acquisition procedures relating to planned systems will not be detailed in this document, but will be investigated by engineering groups of both NPD and BPA and corrective measures implemented.

TABLE 1

Reading Accuracy Summation

Quantity	Dalles	John Day	McNary	Ch Joseph	Ice Harbor	Bonneville	Cougar	Foster	Lookout Point	Average
Watts (Gen)	3%	3.5%	2.7%	3%	2.2%	3.3%	1.5%	1%	2%	2.2%
W-H (Gen) KWH	1 KWH	10	1		1	1	1	1	1	2.1 KWH
Volts	1.5%	10%	.2%	3%	2%	-	1%	.1%	1%	2.4%
Freq	.1 Hz	.02	.02	.01	.1	.1	-	-	1	0.19%
W-H (SS) KWH	50 KWH	1 MWH	40 KWH		1 KWH	-	100	1	100	180 KWH
Watts (Proj)	1.7%	1.5%	2%	1.2%	1.9%	0.5%	-	5%	2%	2%
Var (Proj)	10 MVAR	100	10	10	-	10	-	1	1	20 MVAR
Load Cont Deviation	1 MW	2	5	5	-	5	-	1	-	2.7 MW
W-H (Proj)	10 MWH	10	4.8	6.4	5	10	-	-	1	7 MWH
Forebay Water Level	0.1 ft.	0.1	0.1	0.1	0.1	0.1	.01	1	.01	.18 ft.
Tailwater Level	0.1 ft.	0.1	0.1	0.1	0.1	0.1	.01	.01	.1	.1 ft.
Upstream	ft.	-	-	-	-	0.1	.01	.01	.1	.06 ft.
Downstream	ft.	-	-	-	-	0.1	.01	.01	.1	.06 ft.
Spillway Gate Pos.	0.1ft.	0.5	1.0	0.7	-	-	.1	.01	.1	0.36 ft.
Fish Count	± 5%	5%	-	-	-	2%	-		-	4%
Wind Direction	30°	30°	10°	60°	-	10°	-		0°	23°
Wind Velocity	±5 MPH	5	2		-	10	-		2	± 5 MPH
Precipitation	0.01 ft.	0.01	0.01	0.01"	0.01	0.01	0.01		0.01	0.01
Air Temp	± 1°	± 1°	± 1°	± 1°	± 1°	± 1°	1°		1°	± 1°
Humidity	± 5%	± 5%		-	-	± 5%	-		1%	± 4%
Cloud Cover	± 20%	± 20%		± 25%	± 20%	±20%	-		20%	±21%
Turpidity	± 5%	± 5%		-	± 5%	± 5%	-			± 5%
Water Temp	± 1°		± 2°	0.1°C	1°	1°	-			± 1°

TABLE 2

Instrumentation with Less Than Good Reliability

Project	Data Type	Rating
Albeni Falls	Wattmeter	Poor
	Wind Direction	Fair
	Wind Velocity	Poor
	Humidity	Poor
Chief Joseph	Tailwater Level	Fair
	Wind Direction	Poor
	Wind Velocity	Poor
John Day	Total VAR	Poor
	Forebay Level	Fair
	Tailwater Level	Fair
	Spillway Gate Pos.	Poor
	BPA Swyd BKR Pos.	Fair
Bonneville	Wind Direction	Fair
	Wind Velocity	Fair
Cougar	High Voltage Bus VM	Poor
Ice Harbor	Spillway Gate Pos.	Poor at McNary
	Wind Direction	Poor
	Wind Velocity	Poor
Hills Creek	Watts (Gen)	Fair at LOP
	Watthours (Gen)	Poor at LOP
	Total Watts	Fair at LOP
	Total Watthours	Poor at LOP
	Forebay	Fair
	Tailwater	Fair
	Upstream Level	Fair
	Downstream Level	Fair
	Wind Velocity	Fair
Detroit	Tailwater Level	Fair
	Wind Direction	Poor
	Wind Velocity	Poor

TABLE 3

Multiple Quantities Transmitted

Project	Quantity
Detroit	Watthours (Gen) Watthours (Station Service) Watthours (Proj) "Out of Service" "On Standby"
Lookout Point	Watthours (Proj)
Foster	Watthours (Proj) "Out of Service"
Albeni Falls	Watthours (Proj) Forebay Water Level Tailwater Level Upstream Level Inflow Outflow Wind Direction Wind Velocity Precipitation Air Temp Humidity Cloud Cover
Bonneville	Watthours (Proj) Forebay Water Level "Out of Service" Fish Count (CBTT-MAIL) Precipitation (CBTT-MAIL) Air Temp (CBTT-MAIL) Water Temp (CBTT-MAIL)
Cougar	Watthours (Gen) Watthours (Proj) "Out of Service" Precipitation (LOG-CBTT) Air Temp (LOG-CBTT)
Ice Harbor	"Out of Service" "On Standby"

TABLE 3 - Continued

Project	Quantity
Chief Joseph	On Load Freq Cont
	On Load Cont fm Phse
	"Out of Service"
	"On Standby"
McNary	Watthours (Proj)
	Forebay Water Level
	Turbidity (LOG & MAIL)
	Water Temp (LOG & MAIL)
John Day	Watthours (Proj)
	Forebay Water Level
	Tailwater Level
	"Out of Service"
	"On Standby"

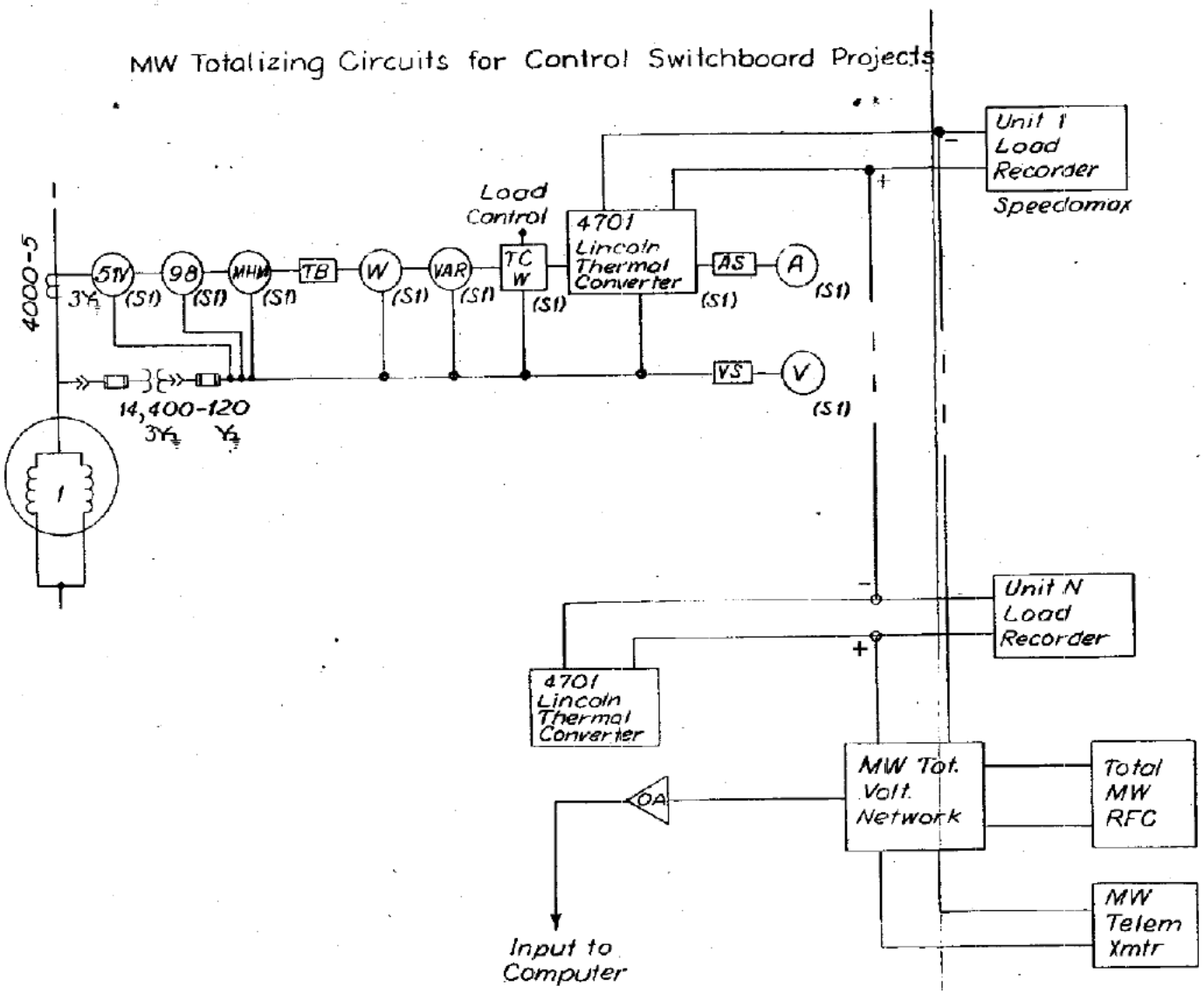
MW Totalizing Circuits for Control Switchboard Projects
4000-5
51N
98
MHM
TB
W
VAR
TC
W
Load
Control
4701
Lincoln
Thermal
Converter
AS
A
VS
V
(S1)
3Y
14,400-120
3Y
Y
1
Unit 1
Load
Recorder
Speedomax
Unit N
Load
Recorder
4701
Lincoln
Thermal
Converter
MW Tot.
Volt.
Network
DA
Total
MW
RFC
MW
Telem
Xmtr
Input to
Computer

Figure 1

MW Totalizing Circuit for Control Console Projects

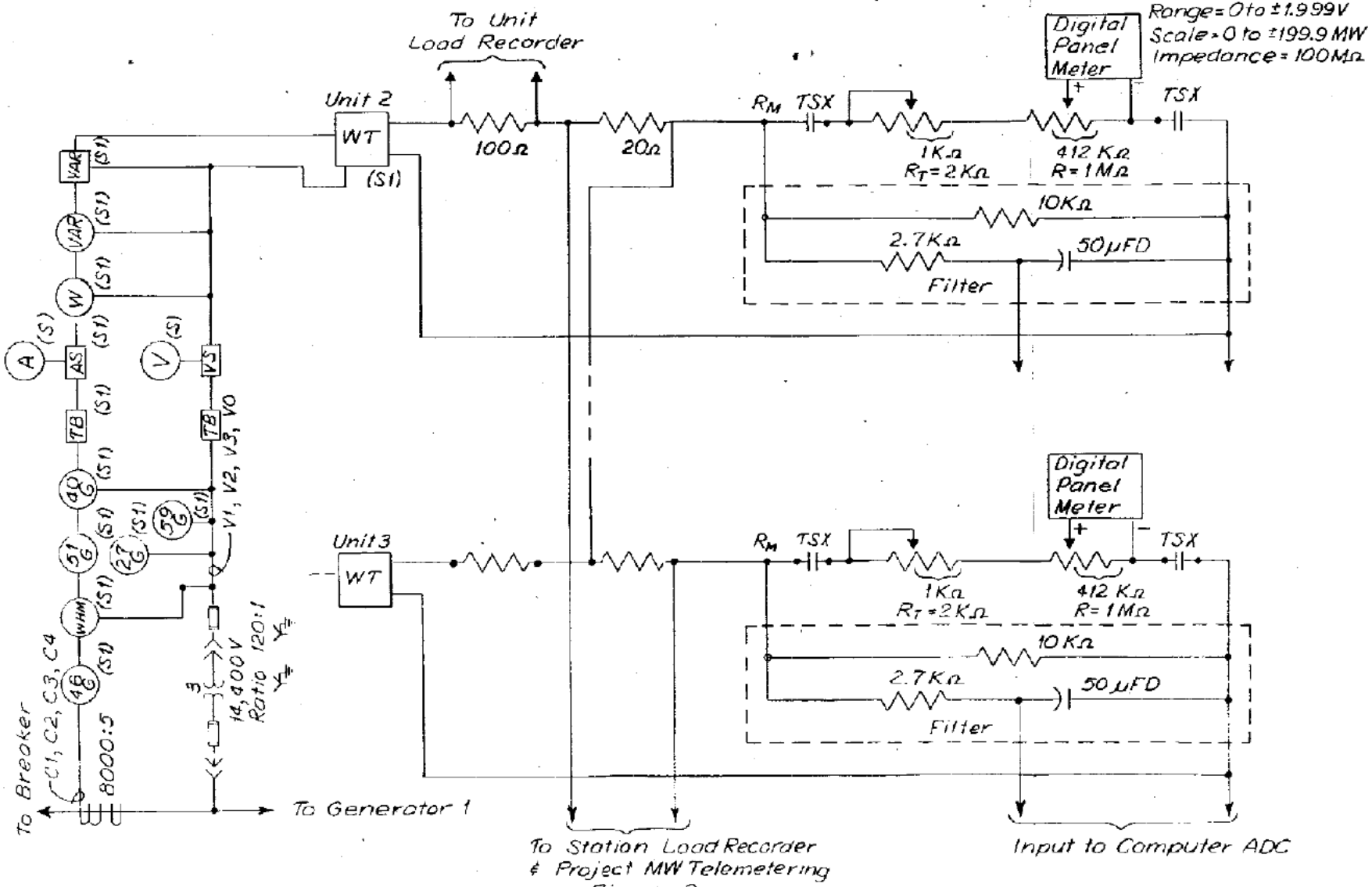

Figure 2

Exhibit No. 2 to
Attachment No. 5 to Exhibit B of
Contract No. 14-03-19250

BPA - Corps Coordination Task Force No. 3

4.0 Develop Design Criteria for Cooperative Data Exchange

4.1 Both the Corps of Engineers and the Bonneville Power Administration make use of nationally recognized standards such as the American National Standards Institute. Both agencies have engineering guidelines and operational requirements which are peculiar to their areas of responsibility. Data system design procedures must be followed which meet "user" requirements for accuracy, reliability, update time, and security. All of the user requirements and engineering design criteria must be considered together with total economics to establish the most effective balance and practical system design to meet the system needs.

4.1.1 Both BPA and the Corps of Engineers will agree to use the same data code structure where feasible. Many of the supervisory control and data transmission manufacturers have adopted BCD (binary coded decimal) formats. Where numerical transmission is involved, some form of BCD or straight binary code structure will be agreed to. Code structure for data interchange between Federal general purpose computers is based upon ANSI 7 level plus parity as implemented by Executive Order. This will be considered although it is not a requirement for dedicated computer systems included in these agreements.

4.2 Define System Configuration

System Configuration - System configuration design for data exchange between BPA and the Corps of Engineers will follow operation and automation needs. The present data transmission from the projects can be grouped into three categories as follows:

(1) High data rate quantities such as the instantaneous generation level and the load frequency signal are transmitted directly between the System Control Center and the powerhouse.

(2) Lower data rate information (scheduled to be energized early in 1971), such as spinning reserve information, is also to be transmitted directly between the powerhouse and the System Control Center.

(3) Slow data rate quantities, such as water level data and watt-hour quantities, are presently transmitted to both BPA and NPD by Columbia Basin teletype circuits.

Future computer data interchange between the powerhouses, NPD and BPA, will make these data automatically available to both the BPA System Control Center and the NPD Reservoir Control Center. Future data system configuration will include increased operating data transmission to and from the powerhouses and System Control Center. Powerhouse computer control systems will need decision-making data such as major changes in load requirements and spinning reserve requirements outside of normal operating range. Both the power-houses and System Control Center will require data which will supplement or supersede operating information now transmitted by

voice communications. The required direct computer links will not replace the present CBTT system since other users and separate functions will be served by its continued operation.

4.2.1 Computer Link - The Corps of Engineers powerhouse computer installations include provisions for full duplex data interchange. Communication between these computers and the dedicated computer used for the future Joint Agency Hydromet Data Bank to be located in the Custom House in Portland is planned. Included will be a full duplex data transmission channel between the Joint Agency Data Bank computer and the BPA System Control Center computer facility to provide for exchange of hydromet data.

4.2.2 Operating arrangements have been adopted under Attachment No. 2 to Exhibit B of Contract No. 14-03-19250 to proceed with spinning reserve data interchange between NPD projects and the System Control Center computer. It is planned that these facilities will include intercomputer data links where possible and will be bi-directional. The data links will carry all data that is required to support load frequency control, spinning reserve, and coordinated power system operation. Forebay and tailwater data will be transmitted via this method from the powerhouses to the System Control Center as category (2) data. At present a dial up interconnection exists between the general purpose computers at BPA and NPD.

4.2.3 To accomplish the present operating requirements for data exchange and control, the NPD and the BPA agree that the data and control update and response times will not exceed the capability of one

full audio channel (bi-directional-full duplex, four-wire characteristics) between each project and the System Control Center and between the System Control Center and the Reservoir Control Center. Additional studies are planned to determine if a wider bandwidth channel is required between the control centers to meet developing requirements. The basis for this agreement is that the present evaluation indicates that all requirements for data and control rates, with consideration for data volume, will not require more than a 2400 baud data channel between any two points of the system configuration.

(AUTHENTICATED COPY)

Exhibit No. 3 to
Attachment No. 5 to Exhibit B of
Contract No. 14-03-19250
Effective Date: October 1, 1979

BPA-Corps Method for Joint Powerhouse Data Acquisition

1. Concept and Basis of Agreement. Mutual agreement regarding the needs of each agency to establish automatic data exchange between powerhouses and control centers, and identifying the nature of the data required, is covered in the Memorandum of Understanding, Contract No. 14-03-19250, specifically in the Operating Arrangements included as Attachments to Exhibit B of said contract.

As the most feasible method of satisfying these needs, the Corps and BPA jointly implemented a system which uses a programmable communication controller to automatically control transmission of data exchange between powerhouse control computers and operations computers at the Corps' Reservoir Control Center and at the BPA System Control Center.

2. Configuration and Schedule. In November, 1972 the communication controller was installed in the Reservoir Control Center at the Custom House for a period of test operation by the Corps. The test operation established interfaces between the controller and the Corps' IBM 360 computer, BPA's CDC 6400 at Portland, and powerhouse computers at McNary (control of Lower Snake), The Dalles, John Day, and Libby.

The communication controller was relocated to Dittmer in September, 1975. At Dittmer, the controller was interfaced to the RODS system in addition to the terminals noted above, with the exception of the CDC 6400.

The communication controller has expansion capability to accommodate future interfaces with other powerhouses involving mutual data requirements of the agencies.

3. Procurement. From the standpoints of compatibility considerations and ease of implementation with regard to the permanent configuration, it was to the advantage of both agencies that BPA undertake the procurement. BPA initiated procurement immediately after completion of the technical specifications jointly prepared by our respective staffs. The procurement included all data modems required at the powerhouses and control centers.

The contractor was required to deliver the controller and necessary data modems to the Custom House where BPA, assisted by the Corps, verified contract fulfillment. Temporary installation, maintenance, and operation of the controller was the responsibility of the Corps. BPA arranged for relocation of the controller to Dittmer after the test period.

4. Responsibilities for Implementation.

a. The Corps:

(1) Made all necessary hardware and software provisions at the powerhouses to effect the required interfaces.

(2) Assisted BPA in preparation of technical specifications for the communication controller and data modems.

(3) Assisted BPA in confirming fulfillment of obligations by the contractor for the communication controller and data modems.

(4) Provided for the temporary installation of the communication controller and necessary interfaces at the Custom House.

(5) Conducted the test operation of the communication controller while at the Custom House and provided for its maintenance during the test period.

(6) Assisted BPA in final testing of the communication controller after installation at Dittmer.

b. BPA:

(1) Prepared the specifications for the communication controller and data modems, with the assistance of the Corps.

(2) Procured the communication controller and data modems.

(3) Provided for the relocation of the controller from the Custom House to Dittmer and for the installation, test, and energization at Dittmer.

(4) Provided for the necessary interfaces at Dittmer.

c. The agencies developed jointly the initial software required by the communication controller to effect the necessary data exchange between computers. After acceptance BPA assumed all software maintenance responsibilities. Software documentation shall be in accordance with BPA STANDARDS FOR SOFTWARE DOCUMENTATION AND SYSTEM CONTROL PROCEDURES FOR REAL-TIME SYSTEMS, except the system review and change procedures shall be modified to the satisfaction of both agencies to provide applicability to the needs and requirements of this specific system. The modifications in the procedures shall be a supplement to this agreement.

5. Cost and Ownership. Each agency shall bear the costs and retain ownership of the installations on its own premises, with the exception of the communication controller. Because each agency will realize significant economies in investment through joint data acquisition, compared to the alternative of separate data acquisition, and in mutual recognition of the interests of each party in insuring that its powerhouse data requirements shall be met, it was agreed that the agencies share equally the initial contract cost of the communication controller (hardware and software).

Each agency shall be responsible for its own software development costs. Where a proposed software addition or change is intended for principal benefit to one agency, the required software development funds shall be provided by that agency.

The controller shall be held in joint ownership.

6. Controller Hardware and Software Changes. All controller hardware and software changes proposed by either agency, now and in the future, shall be fully documented to the original documentation standards and shall be subject to approval by the other agency prior to implementation. Significant changes and additions, those affecting system configuration, shall be processed as amendments to this exhibit. Minor changes may be processed by less formal memoranda, but in any event, software changes shall be subject to the agreed upon procedures, Section 4.c. above. Changes to the controller software shall be made by BPA.

7. Communications Channels. Provisions for communications channels required to support the permanent data system configuration shall be covered under a separate agreement, wherein consideration of other joint channel requirements shall be included.

8. Operation and Maintenance. BPA shall be responsible for, and assume the cost of, operation of the controller. Voluntary controller outages shall be coordinated between personnel to be designated by the respective agencies. BPA shall provide, and assume the cost of, maintenance of the controller hardware to the level necessary to assure continuity of data required by the respective agencies. Maintenance of controller software shall be done by BPA in accordance with agreed upon procedures, Section 4.c. preceding.

9. Cost Sharing Procedures. Since procurement of the controller and data modems was by BPA contract with the contract amount equally shared, the Corps transferred by Standard Form 1080, one-half of the contract amount after joint confirmation of contractual obligations by the supplier.

APPROVED S/ Sterling Munro

Sterling Munro
Administrator
Bonneville Power Administration

APPROVED S/ Richard M. Wells

Richard M. Wells
Division Engineer
North Pacific Division

(AUTHENTICATED COPY)

Attachment No. 6 to Exhibit B of
Contract No. 14-03-19250
Effective Date: January 1, 1971

OPERATING ARRANGEMENT
(Relationship of Hydromet Data to Powerhouse Data System)

SUBJECT: Identification and Definition of Terms, "Hydromet Data" and "Powerhouse Data"

1. This Operating Arrangement is made pursuant to paragraph 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer.

2. Background. Terminology used by the Corps of Engineers and BPA to identify types of data has been at variance with respect to those sets of data identified by the terms "Hydromet Data" and "Powerhouse Data." This discrepancy in definition has been the cause of misunderstandings between the two organizations in meetings where each organization used its own definition in discussions involving data acquisition, transmission, and processing.

In brief, BPA has categorized "Hydromet Data" as that which involves gaged river levels, meteorologic data and other data which is normally sampled at intervals of no less than one hour. Also, BPA has categorized "Plant Data" as all data sampled at a given project which is involved with the real-time control of hydraulic and electric operations at that plant and for which there is a requirement for frequent sampling (continuous up to integrations of values over 6- to 10-minute intervals). Included in this category are both electrical and hydraulic parameters such as values of forebay and tailwater elevations, spill, etc.

The Corps of Engineers has categorized "hydromet data" requirements in accordance with terms used by the Task Force on Hydrometeorological Data Management, of the Water Management Group, in setting up the interagency hydromet data management system. This system is planned to provide hydromet and plant data necessary for hydraulic and day-to-day or hour-to-hour functional management of the Columbia River water resource system, considering all project purposes. It is being designed to supply input data information required for streamflow forecasting and water management activities. The interagency coordination of this work is accomplished by the Columbia River Water Management Group. A task force of that group has completed an analysis of requirements, proposed agency responsibilities, and general formulation of the basic network which would be used for management of the Columbia River system. A Memorandum of Understanding has been agreed to by the Corps of Engineers, BPA, Bureau of Reclamation, Geological Survey, National Weather Service (formerly U.S. Weather Bureau), Forest Service, and Federal Water Quality Agency.

The information in the hydromet data management system from each major water control project includes all information necessary to functional project regulation for all multiple-purpose interests, but it does not include electrical data of the type required for the BPA power system control. Such hydromet data at water control projects includes forebay and tailwater information and many other parameters related to operational control of the project. These are such data as total discharge of water, spill, water quality, total electrical generation on an hourly basis, fish counts, reservoir water temperatures, hydrometeorological elements at the project site, and other miscellaneous data.

The coordination of the hydromet data management system has been and is being coordinated by the Columbia River Water Management Group (formerly the Water Management Subcommittee, CBIAC). The Columbia Basin Teletype Circuit (CBTT) was originated in 1952 by the Hydromet Task force of the Water Management Committee as a special circuit to collect and disseminate operational hydromet data among the various operating agencies in the Columbia Basin. It has been expanded over a period of years to include the collection of data on an hourly basis from major multiple-purpose water control or hydroelectric power projects of various Federal and nonfederal ownerships. It has also been connected with the various offices of the Government agencies including the Corps of Engineers offices in Portland, Walla Walla, and Seattle; the Bureau of Reclamation and National Weather Service offices in Boise; Bonneville Power Administration, National Weather Service, and Geological Survey offices in Portland; and the British Columbia Hydro and Power Authority office in Vancouver, B.C. Inputs to the CBTT facility are manually operated, and transmission speed of data is limited to relatively slow data transmission rates. Output is in the form of hard copy teletype printouts, but the output can also be fed into a computer system for data storage and retrieval.

The automated hydromet data management system is being planned to provide a completely automatic high-speed data collection and processing system, utilizing central "data bank" computers, joined with peripheral process control computers at each major user facility. The automated data collection facility is being planned and implemented on an interagency basis, and will utilize the BPA microwave as a communication backbone network. The data storage and retrieval system is planned for the Corps of Engineers data bank

to be located in the North Pacific Division office. Procurement of this system is planned for 1973. It will have direct access to the BPA SCADA and RODS systems and Corps of Engineers satellite computers. This system will eventually phase out the existing CBTT. It will include high-speed telecommunications and will be accessible by any Government agency who requires hydromet data for operational need.

3. Conclusions. It is concluded that "hydromet data" as used by both agencies will be defined as described above and as used by the Task Force on Hydromet Data Management. "Powerhouse data" includes all data needed for real-time control of hydraulic and electrical operations and for which there is a requirement for frequent sampling (continuous to integrations of values over 5-10 minute intervals).

4. Agreement. Hereafter, when the terms "hydromet data" or "powerhouse data" are used in agreements, correspondence, or other official documents, those definitions stated in "Conclusions" above will be adhered to and mutually understood.

It is further agreed that, in the interests of promoting uniformity in the use of such terms, the Corps of Engineers and the Bonneville Power Administration will urge the acceptance of the above principle in transactions involving the Water Management Group and the Task Force on Operational Hydromet Data Management.

APPROVED /S/ DONALD PAUL HODEL
Acting Administrator
Bonneville Power Administration

APPROVED /S/ ROY S. KELLEY
Division Engineer
North Pacific Division

(AUTHENTICATED COPY)

Attachment No. 7 to Exhibit B of
Contract No. 14-03-19250
Effective Date: January 1, 1971

OPERATING ARRANGEMENT
(Joint Weather and Streamflow Forecasting)

SUBJECT: Analysis of Joint Weather and Streamflow Forecasting and Recommended Procedures

1. This Operating Arrangement is made pursuant to paragraph 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer.

2. Background. The assignment to analyze advantages and disadvantages of joint weather and streamflow forecasting versus existing methods in reality is an assignment to delineate to what extent such methods and facilities already exist and what advantages or disadvantages would result from expanding existing joint efforts and facilities.

Operational control and efficient management of the waters of the Columbia River require a complete knowledge and evaluation of the streamflows under both natural and regulated conditions. These evaluations must reflect current conditions on a real-time basis, and estimates of streamflows based on forecasts of hydrometeorological elements and anticipated reservoir regulation during the forecast period. These forecasts must necessarily be integrated to include the water use requirements for the major water use functions including flood control, irrigation, navigation, and hydroelectric power. Also, water use and regulation must recognize the desirability of maintaining the environmental and esthetic values in the river system, including those related to water quality, fish and wildlife, recreation, and stream beautification.

Forecasts, therefore, must integrate all of the above-listed elements in order to be useful in day-to-day water management decisions. This encompasses a much broader aspect of river management than that required for a single-purpose U.S. Columbia River power system. It involves information pertaining to the operational requirements for project operation, streamflow forecasting, and basic data gathering of several U.S. Government agencies, including the U.S. Bureau of Reclamation, the National Weather Service (formerly U.S. Weather Bureau), U.S. Geological Survey, the Federal Water Quality Agency, U.S. Fish and Wildlife Service, Soil Conservation Service, as well as State agencies. The coordination of the activities of these agencies as related to management of the Columbia River system is accomplished by the Columbia River Water Management Group.

The elements of a model hydrometeorological system used for streamflow forecasting developed by integration of inputs of various types necessary for river management are described in the Progress Reports of the ASCE Task Committee on this subject.[1/]

The basic elements of such a system include:

a. A hydrometeorological observation network of all elements necessary for forecasting streamflow and operating reservoir projects.

b. A communications and data processing system for transmitting, collecting, processing, and disseminating hydrometeorological data on a routine basis.

c. A worldwide weather data, analysis, and forecasting system for supplying necessary meteorological forecasts on a short- and medium-range basis.

1/ Journal of Hydraulics Division, American Society of Civil Engineers, Paper 5342, July 1967, "Progress Report, Task Force on Hydrometeorological Systems"

d. A systematic compilation of project operational criteria, for storage control by reservoirs, considering all water use requirements, both at the reservoir site and at downstream locations.

e. A suitable analog or digital mathematical model for simulating all natural streamflow processes, together with the effects of reservoir control, for a complex river basin, to be used as a forecasting tool, and ultimately to schedule releases on an optimal basis, with consideration and priorities assigned to all uses.

f. A forecast-operational center, or centers, for display of current hydrometeorological data, streamflow forecasts, and operational criteria or restrictions affecting streamflow conditions to be used by operating and management personnel as a tool in decision-making and serve as a center of river intelligence.

Development of such a system for Columbia River water management must be integrated into a comprehensive and coordinated functional unit, involving the several agencies who are responsible for project operation or who have a functional responsibility with respect to streamflow forecasting or water control.

Present day technology in river management is based on use of operational mathematical computer models of river and reservoir systems. Simulation techniques are used for developing alternatives upon which management decisions on river regulation can be based. The ever-increasing demands for water and reservoir regulation on a competitive multi-use basis, together with the ever-changing hydrometeorological conditions which are unique to any particular circumstance, require real-time operational systems

analysis by use of computer models. The input to these models must reflect ever-changing natural phenomena as well as changing water use requirements. Coordination of effort in the areas of operation must begin with a commonly accepted definition of streamflow, reservoir, and water use requirements in the operational forecasting model. It is therefore essential that this work be done jointly as an interagency activity.

With respect to the existing Pacific Northwest water management system, it is our belief that the term "joint" does not necessarily require an immediate proximity of facilities or personnel to have an effective "joint" endeavor, in this case, a joint weather and streamflow forecasting facility. The quality of proximity that has been considered to be an inherent part of any "joint" facility has been displaced by modern computers, modern communications, and the common use of services supplied by a responsible agency or group of agencies. For instance, a joint facility already exists, in fact, between the U.S. Corps of Engineers and the National Weather Service in the Cooperative Columbia River Forecasting Unit (CCRFU). A joint relationship exists between the Bonneville Power Administration (BPA) and the National Weather Service in that National Weather Service basic data, prognostic charts, and general forecasts are used by BPA in preparing specialized weather forecasts and statistical material for BPA's special purposes. A joint relationship exists between the National Weather Service, the U.S. Corps of Engineers, the U.S. Geological Survey, the U.S. Forest Service, BPA, and others in the sense that all the above cooperate to plan, fund, and operate a cooperative hydrometeorological reporting network. Many such relationships are already in existence, many more could be initiated

to the benefit of all concerned, and several are planned and already agreed to in connection with the Corps of Engineers-BPA automation effort.

3. Existing Facilities. In 1963, the U.S. Corps of Engineers and the U.S. Weather Bureau entered into a joint agreement for coordinating streamflow forecasting by the formation of the Cooperative Columbia River Forecasting Unit. A copy of the Memorandum on Program Plan, which describes the functions and operations of the Unit, is attached hereto. This agreement was formalized at the Washington offices of the agencies involved. It has led to the completely coordinated effort of the two agencies involved in developing short-, medium-, and long-range forecasts necessary to meet the functional responsibilities of the agencies. At present, river and weather forecasting by BPA is mostly accomplished independently from the CCRFU.

BPA's streamflow forecasting unit uses weather and streamflow information provided by the National Weather Service, the U.S. Geological Survey, the Corps of Engineers, BPA's specialized weather forecasting staff, and by hydraulically connected power utilities in the Pacific Northwest. This information is processed by BPA's computer facilities to determine inflows to Federal hydroelectric installations and power discharges from these same facilities. The latter information is relayed to the CCRFU and to those utilities whose powerplants will be affected by power discharges from Federal projects.

Of those people at BPA devoting time to hydraulic operations, approximately 0.8 of a man is devoted to forecasting variations in natural flow that affects Federal powerplants. The remainder of the personnel in the Streamflow Forecasting Unit devote their time to hydraulic coordination

of power discharges with other agencies and utilities that are affected by power discharges and to BPA's automation effort.

In the BPA weather forecasting work unit, the efforts of 1.5 men are devoted to satisfying the Administration's needs for specific weather information required in the day-to-day operation of and maintenance of this highly weather-sensitive organization. All such forecasts and statistics are prepared from basic observations, synoptic charts and prognostic charts prepared by the National Weather Service. The liberal use of computer facilities in preparing statistics and forecasts minimizes manpower requirements for this effort. Much of the meteorologic material prepared by this unit would not be of interest to other agencies except perhaps the CCRFU. However, all statistical material of general interest is available to other agencies and, in many instances, has been published as documents under the Pacific Northwest Columbia River Basins Commission, Meteorology Committee.

4. Conclusions

A. A very substantial joint effort is currently in existence in the fields of weather and streamflow forecasting and especially in the planning, support, and operation of the cooperative basic data-gathering system.

B. A substantial increase in the exchange of information between the U.S. Corps of Engineers and BPA is planned and has been agreed to in other attachments to the BPA-U.S. Corps of Engineers Memorandum of Understanding. Much of this information--power scheduling, power discharges, etc.--is derived by integrating weather and streamflow forecasts with numerous other operational considerations.

C. A greater degree of cooperation could be attained by an increase in exchange of data between the CCRFU and the BPA Forecasting Unit. More specifically, the CCRFU could supply daily informational forecasts of natural inflow to major storage reservoirs. The BPA Forecasting Unit could, in addition to supplying initial and final estimates of power discharges, supply the CCRFU with weather forecasts and statistics used by BPA in preparing 10- and 30-day power operating plans.

D. The immediate formation of a cooperative river and weather forecasting facility in one location would not be advantageous. The dislocation from present affiliations of personnel qualified to perform in such a facility would cause a morale problem and would cause an undue disruption of activities in a very crucial period when conversion to automated processing is in midstride. Only a very nominal saving would be accomplished in manpower in that most personnel involved in this activity have dual, vital roles which would require replacement of their talents in the agency losing their services. However, an effective joint weather and streamflow forecasting facility can be attained by a more complete interchange of information, and much can be done to improve this exchange by utilizing modern communication techniques.

E. Several advantages would accrue to the establishment of a joint weather and streamflow forecasting service. With such a service, the best weather and streamflow information being prepared on a current basis would become available to all interested agencies. Present deficiencies in weather and streamflow forecasting techniques could be

resolved from unified, cooperatively sponsored programs. Both manpower and fund savings would be accomplished in a long-term sense as a result of developing a joint working relationship.

5. Agreement. To promote and formalize the development of a joint weather and streamflow forecasting service, the following steps will be taken:

A. Representatives of the U.S. Corps of Engineers, the National Weather Service, and BPA will prepare a list of streamflow points for which forecasts will be made available with a further specification of frequency and duration of such forecasts.

B. Representatives of the U.S. Corps of Engineers, the National Weather Service, and BPA will prepare a list of index points for which weather forecasts and statistics will be made available with a further specification of frequency and duration of such forecasts.

C. The U.S. Corps of Engineers, the National Weather Service (with its consent), and BPA will each appoint a representative who will coordinate his agency's actions in fulfilling the intent of this agreement including the participation in programs initiated to correct deficiencies in existing forecasting procedures and in the interagency coordination of data exchange. BPA's representative will be the Head, Power Scheduling Section, currently, Lenard M. Bissell. The U.S. Corps of Engineers' representative will be the Head, Hydrology and Hydraulics Section, currently David M. Rockwood. The National Weather Service's representative will be appointed by that agency.

D. The group named in item C above will cooperate to modify the exisiting "Memorandum on Program Plan" of the CCRFU (copy attached) to establish a joint weather and streamflow forecasting service on the basis of a joint working relationship of the Corps of Engineers, the National Weather Service, and the Bonneville Power Administration.

Attachment

APPROVED /S/ DONALD PAUL HODEL
Acting Administrator
Bonneville Power Administration

APPROVED /S/ ROY S. KELLEY
Division Engineer
North Pacific Division

COOPERATIVE COLUMBIA RIVER FORECASTING UNIT

United States Weather Bureau
and
United States Army Corps of Engineers

MEMORANDUM ON PROGRAM PLAN

1. PURPOSE OF THIS MEMORANDUM

a. To provide general information regarding the requirements of the Corps of Engineers and Weather Bureau for forecasting streamflow in the Columbia River Basin.

b. To show the feasibility of pooling certain resources of the Portland River Forecasting Center, U. S. Weather Bureau, and the North Pacific Division Office, U. S. Corps of Engineers, in the interest of improving forecasting methods and increasing efficiency of government operations. The program would embrace full utilization of advanced techniques for river forecasting, including application of automatic electronic computers and remote hydrometeorologic reporting equipment including radar, satellites and other sensors of hydrologic information.

c. To reflect a general understanding between the two organizations regarding the proposed activities of the cooperative forecasting unit, the general organization, administration, responsibilities, lines of communication, and other details related to prosecution of studies and operational forecasts.

d. To provide the framework for future modification of the cooperative program as this proves advisable and mutually agreeable to the cooperating agencies.

2. STATEMENT OF PROBLEM

a. General

(1) The Portland River Forecast Center, USWB (hereinafter abbreviated PRFC), is the U. S. government agency responsible for public forecasts of streamflow conditions in the Columbia River Basin and adjacent coastal streams. The North Pacific Division Office of the U. S. Army Corps of Engineers (hereinafter abbreviated NPDO) is responsible for operation of major Corps of Engineer water control projects in the Columbia River Basin, as well as flood control storage of projects under ownership of other federal agencies, PUD's or private companies, for coordinated system multiple-purpose use. Functional requirements of both agencies (PRFC and NPDO) involve streamflow forecasts, on a long-, medium-, and short-range basis. Inasmuch as basic forecasting requirements are essentially the same for both organizations, and reservoir regulation of streamflow affects downstream forecasts for public use,

a high degree of coordination between the agencies is required in meeting their respective missions. Accordingly, the proposed cooperative program is considered to be in the public interest of efficient governmental operation. The combined forecasting facility is to be designated as the Cooperative Columbia River Forecasting Unit.

(2) The PRFC has a staff of trained hydrologists and meteorologists intimately acquainted with the hydrology and forecast problems of the Columbia River Basin. The PRFC has procedures which relate seasonal as well as day-to-day streamflow variation to readily observable hydrometeorologic parameters, for forecasting future runoff events. The PRFC also has direct access to meteorological services provided by the U. S. Weather Bureau. Important resources of the NPDO in the field of streamflow forecasting are the IBM 1920 computer system, the daily snowmelt and reservoir regulation routing program (No. 24.J3.M001) for this computer system, the hydraulic engineer primarily responsible for the program development and its initial application to the Columbia River System, and hydraulic engineers and a meteorologist who are familiar with its use and also are intimately acquainted with the hydrology and forecast problems in the Columbia River Basin. Both agencies have access to the existing Columbia Basin Hydrometeorological Reporting Network, which is operated as an inter-agency function by the Water Management Subcommittee, CBIAC. New, and in some cases still experimental, equipment for measuring hydrologic phenomena is being developed both by the U. S. Weather Bureau and U. S. Corps of Engineers. These devices or techniques currently under operation or being tested by the Weather Bureau include radar weather observing equipment, meteorologic radar transponders, satellite measurements of areal snow cover, and automatic meteorologic observation stations. Automatic equipment being developed by the Corps of Engineers includes a radioisotope snow gage, a sonic gage for determining stream velocities (in conjunction with the U. S. Geological Survey and the State of California), and various hydrologic telemetering devices. Furthermore, much basic research in snow hydrology and in basin application of methods was accomplished jointly by the two agencies under the Cooperative Snow Investigations. The combined resources listed above represent a collective potential for forecasting streamflow, which will far exceed the capability of either agency, operating separately.

(3) Improved methods of forecasting are made possible by use of an electronic digital computer. The computer program referred to in the preceding paragraph is a general and comprehensive program for synthesizing streamflow resulting from either snowmelt or rainfall. It includes evaluation of both natural and controlled storage effects in basins, lakes, reservoirs, and stream channels; computation of daily snowmelt, snow cover depletion, and runoff excess; and derivation of streamflows and reservoir levels for all key locations throughout the basin, in time increments as small as three hours, for unlimited periods of time. The program provides a mathematical model of the river, from which studies of snowmelt runoff variation can be undertaken and results verified with a minimum amount of effort. The coefficients derived from reconstitution studies of historic streamflow data are used in the model

for day-to-day streamflow forecasting, and the accuracy of forecasting is dependent in a large measure on the effort expended in developing those coefficients. Accordingly, it is necessary that the cooperative forecast unit undertake development studies as well as prepare operational forecasts.

b. Columbia River Basin Streamflow Forecasting Requirements

(1) Streamflow in the Columbia River is derived primarily from snowmelt. Forecasting runoff from snowmelt may be divided into categories of time, i.e., long-range, medium-range, and short-range. Long-range forecasts are concerned with estimating volume of runoff several months in advance on a seasonal basis (generally for the period April through September) through estimation of water in storage in the snowpack accumulated during the winter, and evaluation of other hydrologic factors affecting runoff volume. From forecasts of volumes, long-range estimates of peak discharge may be made from statistical relationships between peak and volume. Long-range forecasts of this nature in no way evaluate the effects of meteorological conditions on snowmelt and precipitation during the springtime snowmelt period, except with respect to climatological averages and/or extremes, inasmuch as long-range weather forecasts are unreliable for this purpose. Accordingly, the time distribution of runoff cannot be forecast on a long-range basis except as determined by probabilities of the meteorological variables.

(2) Short-range forecasts of streamflow in the Columbia are concerned with the determination of the chronological distribution of runoff, for periods ranging from two to ten days in advance. These forecasts consider: (a) day-to-day variations in snowmelt and precipitation, either from observation or estimates based on meteorological parameters; (b) forecasts of future weather events which will affect snowmelt and precipitation rates; (c) the volume of water remaining in storage in the snowpack; (d) the areal extent of the snowpack; (e) water loss conditions with respect to ground and soil; (f) the effect of natural storage in basins, lakes, and river channels; (g) the effect of reservoir regulation; and (h) miscellaneous effects of irrigation and return flow. Forecasts of discharge are converted to river elevation at downstream control points for stage forecasts. Reservoir regulation schedules are based on inflows forecast for projects, and controlled flow requirements at downstream points, on an integrated system basis. Short-range forecasts usually are made once daily during the snowmelt period.

(3) Medium-range forecasts may be considered as those for the period between 10 and 30 days in advance of the date of forecast. These forecasts involve the forecast elements specified in paragraph (2) above, except that forecasts of future weather events are based on climatological data of means or extremes, for the period beyond that of accurate weather forecasts. The primary purpose of medium-range forecasts is to define runoff under known snowpack, streamflow, and reservoir conditions, and assumed meteorological conditions, for periods of 30 days or more in advance, in order to assess effects of reservoir filling

schedules and downstream peak discharge potentials. Medium-range forecasts are computed at the same time as short-range forecasts, but they are extended in time for each meteorological condition to be tested.

(4) Winter streamflow forecasts in the Columbia are necessary for multiple-use reservoir regulation. Forecasts fall in the category of short-range and medium-range. During the winter period, streamflow is derived mainly from base flow recession, with occasional moderate rises resulting from winter rains and snowmelt from the low-elevation areas. Because of the relatively slow changes in streamflow during the winter, forecasts of medium-range would be required only once or twice a week.

3. BACKGROUND

a. The Portland River Forecast Center. - In 1946 the U. S. Weather Bureau was granted authority to proceed with their program of providing a modernized river forecast program for the United States. A beginning was made by the establishment of River Forecast Centers at Cincinnati, Ohio, and Kansas City, Missouri. These centers are staffed by trained hydrologists and/or hydrometeorologists devoting full time to river forecasting, development, and refinement of forecasting procedures. The Portland River Forecast Center as such was established in January 1950 and began limited forecasting operations early in 1951.1/ The area of responsibility of the PRFC coincides with that of the NPDO plus the coastal drainage in Northern California down to and including the Eel River Basin. In the near future the coastal drainage area of Northern California will be transferred to the new RFC at Sacramento, California. Since actual operations began in 1951, the PRFC has maintained very cordial and close relationships with the NPDO and the District Offices. During the past three years the PRFC has had the opportunity to utilize the NPDO computer facilities in connection with the Weather Bureau Seasonal Water Supply Forecast Program. So far no attempt has been made to develop a "short range" computer program.

b. Corps of Engineers' Forecast Unit. - The North Pacific Division of the Corps of Engineers has been engaged in Columbia River Basin river regulation, as a system operation, since 1949. This required active study and application of streamflow forecasting problems with regard to flood regulation. The Portland District Office of the Corps of Engineers had prepared long-range forecasts of seasonal runoff volume, primarily in the interest of evaluating flood potentials in the Lower Columbia River, since about 1945. Similarly, the Walla Walla and Seattle Districts have prepared seasonal volume forecasts for specific flood areas in their districts. As more water control projects came into operation

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1/ In the fall of 1947 the Weather Bureau had established a Water Supply Forecast Unit in Portland, Oregon. This unit prepared and issued water year and/or seasonal volume forecasts for approximately 130 locations in the Pacific Northwest. This responsibility was subsequently absorbed by the PRFC.

in the early 1950's, the control of the operation of main-stem projects was centralized in the Water Control Branch of the North Pacific Division Office, and the need for operational forecasts increased. In 1956, the NPDO acquired an IBM 650 Electronic Digital Computer and a computer program was developed for synthesizing streamflow from snowmelt. This program was used on a forecast basis for the years 1957 through 1961, and provided the capability of extending short-range forecasts to about ten days. A new computer (the IBM 1620 system) was installed in 1962, and the streamflow routing program was rewritten for this system which greatly extended the short- and medium-range forecast capability.

4. TECHNICAL OBJECTIVES

Technical objectives of the joint forecast unit include the following:

a. Derive snowmelt and routing coefficients for use in the computer for drainage basins contributing to the Columbia River above The Dalles, Oregon.

b. Perform daily forecasts of streamflow at key points in the Columbia River Basin, on a short- and medium-range basis, to meet operational requirements of the Weather Bureau and Corps of Engineers.

c. Derive relationships between hydroclimatic variables (including snow survey data) and seasonal runoff volume, for long-range forecasting of runoff required for tributaries used in short-range forecast procedures, as well as those required for normal water supply forecasting in the Columbia River Basin. These studies would be accomplished through use of the 1620 computer system, with existing statistical regression analysis programs.

d. Perform long-range forecasts of seasonal runoff volume, to meet operational requirements of the Weather Bureau and Corps of Engineers.

5. SCOPE OF PROPOSED STUDIES

a. Derivation of snowmelt and routing coefficients. - Sufficient reconstitutions of historic streamflow studies will be made to define adequately the indexes of daily snowmelt runoff, basin snow-covered area, rainfall indexes, and basin storage routing characteristics, for each of approximately 25 major tributary drainages of the Columbia River above The Dalles, Oregon. In general, this will involve studies of three to four spring snowmelt periods of approximately 60 days each, and testing derived values independently on one or two years' data. Indexes of snowmelt will generally be based on maximum daily air temperature values at representative stations, but in some cases other parameters may be included as necessary. Studies of streamflow routing in channels and reservoirs will also be performed, and routing coefficients will be derived for all river channels, lakes, and reservoirs in the Columbia River Basin above The Dalles, Oregon, for use in day-to-day streamflow

forecasting by computer program 24.J3.H001. Studies of a similar nature will be undertaken for winter low-flow periods.

b. Derivation of seasonal runoff forecast procedures. - Seasonal runoff forecasting procedures will be reanalyzed, in order to make full use of snow survey data now available, as well as all other hydrometeorological data to index significant items in the water balance of the various drainages of the Columbia Basin. The procedures will provide for ability to forecast seasonal runoff volume beginning on 1 January of each year, with the further provision to adjust forecasts at least monthly up to 1 July of each year, on the basis of current hydrologic data. Key gaging stations for which forecasts are to be made will include those areas for which day-to-day streamflow forecasts are to be made. Correlations of indexes of hydrologic elements will be performed by standard regression analysis, using IBM 1620 computer programs presently existing, but adapted to the IBM 1920 computer system for rapid input and output. Correlations will be based insofar as possible on indexes of all hydrologic parameters that are known to affect significantly the water balance of the area concerned.

6. PROPOSED OPERATIONAL PROCEDURES FOR DAY-TO-DAY FORECASTING, COLUMBIA RIVER ABOVE THE DALLES, OREGON.

a. General. - Day-to-day forecasting of streamflow variation in the Columbia Basin is becoming more objective as knowledge of snowmelt phenomena is being applied. One of the principal tools now available to hydrologists for meeting the goal of strictly objective forecasting is the electronic digital computer. Ultimately, day-to-day streamflow forecasts by electronic computer will supplant less rigorous "hand" methods or purely subjective forecasts, because of the ability to simulate river conditions by electronic computer in much greater detail than can be done otherwise. Furthermore, the knowledge gained from comprehensive studies of snowmelt runoff, in the form of snowmelt coefficients, melt rates, routing coefficients, snow cover depletion curves, etc., can be retained for ready use by the computer. The principles involved in computer forecasting techniques have been tested over the past several years and those tests have shown the computer method to be feasible and capable of producing the required forecasts within time requirements necessary for the Corps of Engineers' operation.

b. Procedures. - The use of the computer for operational forecasting in the Columbia Basin has, up to this time, been restricted to the Corps. Accordingly, a period of familiarization is required for Weather Bureau personnel to study the fundamental principles of the computer technique, and to become proficient in its use on an operational basis. Electronic computer and "hand" methods will be used for the first year or two of operation by the Cooperative Columbia River Forecasting Unit.

c. Facilities. - It is highly desirable that the physical location of the Cooperative Columbia River Forecasting Unit be adjacent to offices of both agencies. A Technical Committee (described in paragraph 10b) will be responsible for planning arrangements to provide a facility

for maintaining displays of meteorological, hydrologic, and other pertinent data on a current basis that will be convenient to both offices. Space will also be provided as necessary for preparation of forecasts.

d. Springtime forecasts. - Both short- and medium-range forecasts will be prepared daily during the spring flood season. Medium-range forecasts will be computed on at least two conditions of snowmelt (maximum and normal) for the period beyond the time of accurate weather forecasts. Additional forecasts may be prepared, as required, when unusual conditions warrant them.

e. Low-flow period forecasts. - Short-range forecasts will be prepared daily during periods of low flow. Medium-range forecasts will be prepared once weekly or more frequently when conditions warrant it. Medium-range forecasts will be based on at least two conditions of runoff (normal and below normal) for the period beyond the time of accurate weather forecasts. Forecasts of power loadings and reservoir drawdown for power operation will be provided by the MPDO.

7. PROPOSED OPERATION FOR SEASONAL RUNOFF FORECASTING

a. General. - Seasonal runoff forecasting will be accomplished in accordance with operational procedures already established by the U. S. Weather Bureau for Water Supply Forecasts for the Western States. Forecasts will be prepared for all locations required by the Corps of Engineers and the U. S. Weather Bureau for reservoir regulation, day-to-day forecasting, and flood potential evaluation. Forecasts will be made at least once each month, between 1 January and 1 June of each year. Additional forecasts may be made as required when conditions warrant.

b. Procedures. - Forecasting relationships presently available in the PRFC may be used for at least the first year of the operation of the Cooperative Columbia River Forecasting Unit. With the completion of studies outlined in paragraph 5(b), there will be a transition to use the revised forecast procedures. Computation of forecasts will be accomplished by electronic computer, in general accordance with methods presently being used by the PRFC, but adapted to the revised forecast procedures.

8. PERSONNEL. - It is anticipated that initially the joint river forecast unit will be staffed by the present staff of the PRFC, possibly augmented by one trained hydrologist. The Corps of Engineers plans to attach one hydrologist on a full-time basis. Close supervision of the electronic computer forecasts is to be maintained by the hydraulic engineer responsible for the present computer program 24.J3.H001 on a part-time basis, as required.

9. ELECTRONIC COMPUTER MACHINE TIME

a. Machine time on the IBM 1920 computer system will be provided by the NPDO, to the extent required for study purpose and operational forecasts outlined in paragraphs 5, 6 and 7. These river forecasting activities will have a high priority for computer time.

10. ADMINISTRATION

a. General. - Administration of personnel attached to the joint unit will be maintained by their respective parent organizations, and all costs pertaining to personnel will be borne by their respective agencies. The cost of machine time will be borne by the NPDO.

b. Technical Committee. - General technical supervision of the joint unit will be accomplished through a Technical Committee as mutually agreed upon by representatives of the supporting agencies. This committee will meet monthly, or as otherwise required, to agree upon programs of studies to be undertaken, methods to be used, specific types of forecasts required, and other matters related to operation of the unit. The Technical Committee will be delegated appropriate authority to facilitate execution of the cooperative program, but policy matters are subject to review and concurrence as may prove desirable by responsible officials of the cooperating agencies. Nothing in this or subsequent memoranda by the Technical Committee is to be construed as changing the basic responsibilities of the cooperating agencies relating to their normal missions.

11. DISPLAY AND BRIEFING ROOM

a. Graphic display of hydrometeorologic data. - A facility will be provided for display of hydrologic and meteorologic data, with both current and forecast values, in the form of graphic plots. A room will be provided as close as possible to the Water Control Branch, NPDO, for housing this facility. It will be the ultimate objective to use machine methods for plotting information.

b. Daily briefing. - A formal briefing on weather and streamflow conditions will be held each work day in the Display and Briefing Room, to provide current information on hydrometeorological and reservoir conditions to operating and management personnel of the Corps of Engineers. Specific details of type of information and times of briefing will be arranged by the Technical Committee.

12. FUTURE MODIFICATIONS IN PROGRAM

a. Supplementary guidance memoranda and informal agreements will be formulated as studies progress to facilitate efficient attainment of objectives substantially as indicated herein. Any major revisions in the objectives or scope of the program as outlined herein which the Technical Committee or other responsible representatives of the cooperating agencies may consider desirable or necessary in the future will be made the subject of supplemental discussions and agreements.

b. It is anticipated that certain personnel training will constitute a necessary and valuable activity in connection with the subject program. The nature and scope of such activities will be as agreed upon by the Technical Committee from time to time, subject to the comments presented in paragraph 12a.

13. STATUS OF THIS MEMORANDUM

a. This memorandum is intended to reflect the understandings reached in a conference held in the office of the Division Engineer, Army Corps of Engineers, Portland, Oregon, 24 October 1962, which was attended by agency representatives listed in Inclosure 1 herewith.

b. Any formal agreements pertaining to the subject program that may be deemed necessary by central offices of the cooperating agencies will be established through an appropriate exchange of correspondence between the Chief of Engineers, CE, and the Chief, USWB, or by other mutually acceptable means. The Chief of Engineers will initiate such action upon official recommendation of the Division Engineer, NPD.

1 Incl
Attendance List, 24 Oct 62

AUTHENTICATED COPY

Attachment No. 8 to Exhibit B of
Contract No. 14-03-19250
Effective Date: February 1, 1971

OPERATING ARRANGEMENT
(Generation and Transmission Relationship)

SUBJECT: Relationship Between Transmission Line Loadings and Generation Schedules

1. This Operating Arrangement is made pursuant to paragraph 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer.

2. General. The North Pacific Division (NPD) and the Bonneville Power Administration (BPA) have agreed upon certain principles and procedures for coordination of engineering planning, operation, and maintenance of the NPD projects and the BPA transmission system.

3. Principles.

A. NPD has responsibility for planning, design, construction, and operation of multiple-purpose projects, and for establishing appropriate operating limits for the projects. NPD also has responsibility for scheduling plant maintenance, and for operating the reservoirs for all authorized purposes.

B. BPA has responsibility for planning, design, construction, maintenance, and operation of the transmission system necessary to market power generated at NPD and other projects. BPA also has responsibility for estimating future load growth, recommending future Federal generating resource installations, entering into contracts for sale and exchange of power, coordinating NPD project maintenance with that of

other projects for which BPA has marketing responsibility, coordinating power loads and resources with interconnected utilities, and for dispatching of power generation and transmission.

C. NPD and BPA agree to plan, design, construct, operate, and maintain their respective facilities for the purpose of achieving maximum overall efficiency and reliability of operation.

4. Procedures.

A. BPA and NPD will coordinate the design and construction of generating stations and transmission system to insure that adequate transmission line capacity, voltage control, generator control, and protection systems are available to market available generation.

B. BPA and NPD will collaborate in the operation and maintenance of the generating stations and transmission system to insure most efficient use of available water, and most reliable service to power purchasers, consistent with other NPD project purposes.

(1) Generator maintenance schedules at NPD projects will be developed in cooperation with BPA to optimize the overall use of available resources. This includes minimizing adverse effects upon power requirements, and optimizing use of project staff, equipment, and funds.

(2) Transmission system maintenance will be scheduled so that its adverse effect upon power generation and transmission is minimized.

(3) The transmission system will be operated in such a manner that it does not jeopardize generating station equipment or personnel.

(4) Generating stations will be operated in such a manner as to maintain transmission system scheduled voltage levels within the limits of generator capability. Other equipment such as supplementary excitation control and generation tripping schemes shall be maintained in service as required by BPA to insure reliability and stability of the transmission system.

(5) Distribution of total Federal System Load among NPD and other interconnected Federal generating stations will recognize transmission system limitations, most efficient use of water for power production, and other nonpower functions of such projects.

APPROVED /S/ H. R. RICHMOND
Administrator
Bonneville Power Administration

APPROVED /S/ ROY S. KELLEY
Division Engineer
North Pacific Division

AUTHENTICATED COPY

Attachment No. 9 to Exhibit B of
Contract No. 14-03-19250
Effective Date: February 1, 1971

OPERATING ARRANGEMENT
(Operation During Emergency Conditions)

SUBJECT: Principles and Procedures for Powerhouse and Transmission System Operation During Emergency Conditions

1. This Operating Arrangement is made pursuant to paragraph 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer

2. General. The North Pacific Division (NPD) Operations Division and the Bonneville Power Administration (BPA) Branch of System Operations have agreed upon certain principles and procedures for mutual assistance during power system emergency conditions.

3. Principles.

A. BPA system power dispatchers have the responsibility for maintaining reliable operation of the power transmission system, for protecting lives and equipment and for meeting power system emergency conditions as they arise.

B. NPD power project operators have the responsibility for maintaining reliable and safe operation of their projects for all project purposes, for the project effects upon upstream reservoir levels and downstream flows, for protecting lives and equipment, and for meeting power system and other emergency conditions as they arise.

4. Procedures.

A. If either the NPD power project operator or the BPA system power dispatcher determines that he has an emergency, either in the

power project or on the power transmission system, each party will do all within his power to assist the party in trouble. If it is necessary to violate any hydraulic or electrical limitations, the power project operators or system power dispatchers shall report through their appropriate command channels.

B. To meet emergency conditions, power project limits may be exceeded as follows:

(1) Rate of Fluctuation of Generation. All such limits may be waived, subject to imminent danger to life or property.

(2) Temporary Overdraft or Surcharge. Authorized maximum or minimum reservoir or pool limits may be exceeded by 1/2 foot.

(3) Generator Overloads. Short time overload capability is listed in Table 4 of Normal Operating Limits.

C. In the event an emergency on the BPA transmission system results in the occurrence of high voltage that might damage NPD power project equipment or endanger power project personnel, the BPA system power dispatcher will immediately take corrective action.

APPROVED /S/ H. R. RICHMOND
Administrator
Bonneville Power Administration

APPROVED /S/ ROY S. KELLEY
Division Engineer
North Pacific Division

(AUTHENTICATED COPY)

Exhibit No. 3 to
Attachment No. 5 to Exhibit B of
Contract No. 14-03-19250
Effective Date: June 1, 1972

BPA-Corps Method for Joint Powerhouse Data Acquisition

1. Concept and Basis of Agreement. Mutual agreement regarding the needs of each agency to establish automatic data exchange between powerhouses and control centers, and identifying the nature of the data required, is covered in the Memorandum of Understanding, Contract No. 14-03-19250, specifically in the Operating Arrangements included as Attachments to Exhibit B of said contract.

As the most feasible method of satisfying these needs, the Corps and BPA shall jointly implement a system which uses a programable communication controller to control automatically transmission of data exchange between powerhouse control computers and operations computers at the Corps' Reservoir Control Center and at the BPA System Control Center.

2. Configuration and Schedule. Initially the communication controller will be installed in the Reservoir Control Center at the Custom House for a period of test operation by the Corps. If procurement can be expedited this test can start as early as August 1972. For the test operation, it is planned to establish interfaces between the controller and the Corps' IBM 360 computer, the Columbia Basin Teletype, BPA's CDC 6400 at Portland, and powerhouse computers at McNary (control of Lower Snake), The Dalles, and John Day.

After installation of BPA's RODS computers at the W. A. Dittmer BPA System Control Center, the communication controller will be relocated

to Dittmer. Relocation should take place no later than April 1973. At Dittmer, the controller will be interfaced to the RODS system in addition to the terminals noted above.

The interface to the 6400 is temporary and shall be removed when the RODS interface and RODS programs for outputting reservoir data become operational, at which time the communication controller will convert from test to operational status. The scheduled date is July 1973.

The communication controller shall have expansion capability to accommodate future interfaces with other powerhouses involving mutual data requirements of the agencies.

3. Procurement. From the standpoints of compatibility considerations and ease of implementation with regard to the permanent configuration, it is to the advantage of both agencies that BPA undertake the procurement. BPA shall initiate procurement immediately after completion of the technical specifications presently under joint preparation by our respective staffs. The procurement will include the data modems required at the powerhouses and control centers.

The contractor shall be required to deliver the controller and necessary data modems to the Custom House where BPA, assisted by the Corps, shall verify contract fulfillment. Temporary installation, maintenance, and operation of the controller shall be a responsibility of the Corps. BPA shall arrange for relocation of the controller to Dittmer after the test period.

4. Responsibilities for Implementation.

a. The Corps shall:

(1) Make all necessary hardware and software provisions at the powerhouses to effect the required interfaces.

(2) Assist BPA in preparation of technical specifications for the communication controller and data modems.

(3) Assist BPA in confirming fulfillment of obligations by the contractor for the communication controller and data modems.

(4) Provide for the temporary installation of the communication controller and necessary interfaces at the Custom House.

(5) Conduct the test operation of the communication controller while at the Custom House and provide for its maintenance during the test period.

(6) Assist BPA in final testing of the communication controller after installation at Dittmer.

b. BPA shall:

(1) Prepare the specifications for the communication controller and data modems, with the asistance of the Corps.

(2) Procure the communication controller and data modems.

(3) Provide for the relocation of the controller from the Custom House to Dittmer and for the installation, test, and energization at Dittmer.

(4) Provide for the necessary interfaces at Dittmer.

c. The agencies shall develop jointly the initial software required by the communication controller to effect the necessary data exchange between computers. Software documentation shall be in accordance with BPA STANDARDS FOR SOFTWARE DOCUMENTATION AND SYSTEM

CONTROL PROCEDURES FOR REAL-TIME SYSTEMS, except the system review and change procedures shall be modified to the satisfaction of both agencies to provide applicability to the needs and requirements of this specific system. The modifications in the procedures shall become a supplement to this agreement.

5. Costs and Ownership. Each agency shall bear the costs and retain ownership of the installations on its own premises, with the exception of the communication controller. Because each agency will realize significant economies in investment through joint data acquisition, compared to the alternative of separate data acquisition, and in mutual recognition of the interests of each party in insuring that its powerhouse data requirements shall be met, it is agreed that the agencies shall share equally the initial contract cost of the communication controller (hardware and software).

After delivery each agency shall be responsible for its own software development costs. Each agency shall contribute manpower to joint usage software features development without transfer of funds between agencies.

The controller shall be held in joint ownership.

6. Controller Hardware and Software Changes. All controller hardware and software changes proposed by either agency, now and in the future, shall be fully documented to the original documentation standards and shall be subject to approval by the other agency prior to implementation. Significant changes and additions, those affecting system configuration, shall be processed as amendments to this exhibit. Minor changes

may be processed by less formal memorandums, but in any event, software changes shall be subject to the agreed upon procedures, Section 4.c. above. Where a proposed software addition or change is intended for principal benefit to one agency, the required software development shall be provided by that agency.

7. Communications Channels. During the period of test operation at the Custom House, BPA shall provide microwave channels from The Dalles, McNary, and John Day to the BPA Portland Control Center and the Corps shall provide for channel extensions from BPA Portland to the Custom House.

Provisions for communications channels required to support the permanent data system configuration shall be covered under a separate agreement, wherein consideration of other joint channel requirements shall be included.

8. Operation and Maintenance. Upon completion of controller installation and testing in the BPA Control Center, BPA shall be responsible for, and assume the cost of, operation of the controller. Voluntary controller outages shall be coordinated between personnel to be designated by the respective agencies. BPA shall provide, and assume the cost of, maintenance of the controller hardware to the level necessary to assure continuity of data required by the respective agencies. Maintenance of controller software shall be in accordance with agreed upon procedures, Section 4.c. preceding.

9. Cost Sharing Procedures. Since procurement of the controller and data modems will be by BPA contract with the contract amount equally shared, the Corps will transfer by Standard Form 1080 one-half of the

contract amount after joint confirmation of contractual obligations by the supplier.

10. Key Man Designation. To assure continuing availability of system expertise, each agency agrees to designate, upon execution of this agreement, at least one design engineer, who is to maintain intimate technical familiarity with the communication controller hardware and software.

APPROVED /S/ Bernard Goldhammer
Acting Administrator
Bonneville Power Administration

APPROVED /S/ K. T. Sawyer
Division Engineer
North Pacific Division

contract amount after joint confirmation of contractual obligations by the supplier.

10. Key Man Designation. To assure continuing availability of system expertise, each agency agrees to designate, upon execution of this agreement, at least one design engineer, who is to maintain intimate technical familiarity with the communication controller hardware and software.

APPROVED /S/ Bernard Goldhammer
Acting Administrator
Bonneville Power Administration

APPROVED /S/ K. T. Sawyer
Division Engineer
North Pacific Division

EXHIBIT B
Contract No. 14-03-19250
Revised 12-20-74

DETAILED OPERATING ARRANGEMENTS

Attached to this Exhibit B are the following operating arrangements, and amendments thereto:

	Attachment	Effective Date
1.	Reservoir Regulation and Power Scheduling	November 16, 1970
2.	Spinning Reserve and Other Reserve Capability	November 16, 1970
3.	Powerhouse Control	November 16, 1970
4.	Dispatcher-Operator Working Relations	November 18, 1970
5.	Data Acquisition, Engineering, and Planning	December 1, 1970
6.	Relationship of Hydromet Data to Powerhouse Data System	January 1, 1971
7.	Joint Weather and Streamflow Forecasting	January 1, 1971
8.	Generation and Transmission Relationship	February 1, 1971
9.	Operation During Emergency Conditions	February 1, 1971
10.	Use of Powerhouse Space by BPA	December 1, 1973
11.	Joint Planning and Use of Telecommunication Facilities	September 1, 1974
12.	Provisional Draft of Reservoirs	December 1, 1974

Attachment No. 11 to Exhibit B
of Contract No. 14-03-19250
Effective Date: September 1, 1974

OPERATING ARRANGEMENT
(Joint Planning and Use of Telecommunications Facilities)

SUBJECT: Principles and Procedures Relating to the Joint Planning and Use of Telecommunications Facilities

1. This Operating Arrangement is made pursuant to section 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer.

2. General. The North Pacific Division (NPD) and Bonneville Power Administration (BPA) agree to cooperate in providing necessary telecommunications for the operation of NPD-hydroelectric projects within the BPA marketing area.

3. Principles. BPA and NPD are in agreement on the following principles:

   (a) BPA has the responsibility for providing the telecommunications necessary for the operation of the BPA transmission grid system.

   (b) NPD has the responsibility for providing telecommunications for the operation of projects listed in Exhibit A.

   (c) BPA and NPD agree to develop telecommunications jointly as set forth in Exhibits to this Operating Arrangement and as required by each project listed in Exhibit A.

4. Sharing of Facilities. NPD and BPA shall share in the design, construction, installation, operation, and maintenance of telecommunication facilities (Shared Facilities) as agreed by the parties in Exhibits attached hereto as provided in section 9 of this operating agreement, and according to the priority of use as designated in section 10.

5. Design, Purchase, Construction and Installation of Facilities.

   (a) BPA shall prepare all designs for the construction and installation of Shared Facilities and purchase and install such facilities as specified in Exhibits attached hereto. Specifications for such facilities shall be jointly developed by the parties hereto.

   (b) Each party hereto shall design, purchase, and install any communications facilities which shall be exclusively used by such party.

   (c) Each party hereto shall provide the housing for the telecommunication equipment installed at, or on its property; provided, however, that NPD may, with BPA approval, install facilities in BPA's stations which shall be for the exclusive use of NPD to interconnect its Projects and offices to the Shared Facilities.

6. Payment for Construction of Shared Facilities. NPD shall reimburse BPA for NPD's share of the cost and expense, including overhead, incurred by BPA for the Shared Facilities installed in accordance with section 4 by transfer of funds by Standard Form 1080 (Form SF 1080). For budget planning purposes BPA shall furnish NPD quarterly estimates of planned fiscal year procurement, installation, and maintenance costs.

Allocation of investment costs in Shared Facilities installed under this operating arrangement will be based on the ratio of proportionate use of such facilities and on other factors as agreed by the parties.

7. Maintenance.

(a) Performance Responsibilities. Unless specifically designated otherwise in this operating arrangement, or in the exhibits attached hereto, BPA shall perform all maintenance, including replacement of parts, of all microwave and other radio facilities identified in said exhibits. Such facilities include repeater station equipment, microwave and other radio equipment terminals, antennae, RF and channelizing equipment, and service power supplies; except that where facilities are located in Corps powerhouses or dams, NPD shall maintain the service power supplies, including battery chargers, batteries, a.c. supplies, and external cable systems.

Maintenance by BPA shall be performed in the same manner in which BPA maintains similar equipment of BPA ownership. To restore communications or prevent loss of communications, maintenance personnel shall be subject to call on a 24-hour basis by either party.

(b) Cost Sharing and Payment. Maintnenance costs for shared facilities, including all replacement parts and overhead expenses, shall be shared on the basis of the proportionate channel usage by the parties hereto as established at the start of each fiscal year.

NPD shall reimburse BPA for NPD's share of the costs and expenses, including overhead, incurred by BPA for maintenance of facilities, as specified herein, by transfer of funds on Form SF-1080. Such reimbursement for each fiscal year shall be determined by BPA and verified by NPD prior to such fiscal year, based on estimates of operation and maintenance of the equipment during the preceding fiscal year.

Access arrangements for equipment maintenance shall be as agreed by the parties in exhibits to be attached hereto. Maintenance costs for facilities, including replacement parts, used exclusively by NPD shall be borne by the NPD.

8. Replacement or Addition of Facilities. NPD and BPA shall agree to add the required equipment, or if necessary, to replace the existing equipment to provide the capability required at each Project. Disposal or use of salvaged equipment in which both parties have interest shall be mutually agreed by the parties prior to such disposal or use. Any monies realized from salvaged equipment caused by replacement shall be credited to each of the parties in the same pro rata share as allocation for the original investment.

9. Additional Exhibits.

(a) BPA shall prepare, for concurrence and execution by the parties hereto, an additional Exhibit to this operating arrangement each time the parties hereto agree that facilities shall be added or modified as provided herein. Such Exhibit shall specify the facilities to be installed, the work to be performed by each party and the estimated costs to be borne by each party.

(b) Upon execution by the parties hereto, new Exhibits shall be attached to and deemed to be a part of this operating arrangement and shall be effective on the date specified therein.

10. Channel Use and Priority. Additional channels or specific facilities (such as closed circuit television) within the affected microwave paths capability limits may be added subsequently by either agency as needed. Such additions shall have the consent of the other agency. When microwave path capability limits are reached, additional high priority channels will be added by releasing lower priority channels. The lowest priority channel in use by either agency shall be released for the new higher priority channel subject to the consent of both agencies. Channel priority shall be as follows:

(a) Line relaying.

(b) Remote control and telemetering.

(c) Voice communications with dispatcher.

(d) Data transmission.

(e) UHF or VHF voice communications radio.

(f) Miscellaneous voice communications.

APPROVED _____
Administrator
Bonneville Power Administration

APPROVED _____
Division Engineer
North Pacific Division

Exhibit 1 to
Attachment No. 11 to Exhibit B
of Contract No. 14-03-19250

DETAILED PROJECT AND OWNERSHIP DESCRIPTION
(From McNary Dam to Projects in the Lower Snake and Clearwater River Area)

1. Ice Harbor Project.

   (a) McNary-Kennewick path

      (1) Initial investment for a 12 channel microwave system will be borne by BPA.

      (2) The cost of the 12 channel incremental multiplex addition required by the Corps for the Ice Harbor Project, including relocation of the McNary RF terminal and reflector from the substation to the powerhouse, will be borne by the Corps.

      (3) BPA will bear switchyard connection costs and the Corps will bear the cost of cable connection terminations at the powerhouse.

   (b) Kennewick-Ice Harbor path

      The entire cost of the microwave system will be borne by the Corps.

2. Lower Monumental Project.

   (a) McNary-Kennewick path

      The cost of the 12 channel incremental multiplex addition required by the Corps will be borne by the Corps.

   (b) Kennewick-Kahlotus and Kahlotus-Pomeroy paths

      BPA is providing initially a RF microwave path from Kennewick to Pomeroy with a building at Pomeroy to provide VHF service in the area. BPA will redirect the Kennewick and Pomeroy RF installations for transmission to Kahlotus. At Kahlotus, BPA will provide a building and RF equipment for both the Kennewick path and the Pomeroy paths.

   (c) Kahlotus-Lower Monumental path

      Initial requirements are for 12 channels for the Corps and 6 channels for BPA. BPA will provide for the RF at Kahlotus and the Corps will provide for the RF and multiplex equipment at Lower Monumental. The cost of the reflector at Lower Monumental will be borne by the Corps.

(d) Kennewick-BPA system

The cost of the 6 channel incremental multiplex addition required by BPA will be borne by BPA.

(e) Pomeroy VHF Equipment

The cost of the additional VHF equipment required by the Corps will be borne by the Corps.

3. Little Goose Project.

(a) McNary-Kennewick path

The cost of the additional 12 channels of multiplex equipment required by the Corps will be borne by the Corps.

(b) Kennewick-Kahlotus path

The additional facilities will be supplied by BPA.

(c) Kahlotus-Little Goose path

Initial requirements are for 12 channels for the Corps and 6 channels for BPA. BPA will provide for the RF equipment at Kahlotus and the Corps will provide for the RF and multiplex equipment at Little Goose. The cost of the reflector at Little Goose will be borne by the Corps.

(d) Kennewick-BPA system

The cost of the 6 channel incremental multiplex addition required by BPA will be borne by BPA.

4. Lower Granite Project.

(a) McNary-Kennewick path

The cost of the additional 12 channels of multiplex equipment required by the Corps will be borne by the Corps.

(b) Kennewick-Kahlotus path and Kahlotus-Pomeroy path

The additional facilities will be supplied by BPA.

(c) Pomeroy-Lower Granite path

Initial requirements are for 12 channels for the Corps and 6 channels for BPA. BPA will provide for the RF at Pomeroy and the Corps will provide the RF and multiplex equipment at Lower Granite. The cost of the reflector at Lower Granite will be borne by the Corps.

(d) Kennewick-BPA system

The cost of the 6 channel incremental multiplex addition required by BPA will be borne by BPA.

5. Walla Walla District Office Project.

(a) McNary-Kennewick path

The cost of the additional channels of multiplex equipment shall be shared equally by BPA and the Corps.

(b) Walla Walla-Kennewick path

The entire cost for the microwave system will be borne by the Corps.

(c) Kennewick VHF Equipment

The cost of the additional VHF equipment required by the Corps will be borne by the Corps.

6. Dworshak Project.

(a) McNary-Kennewick path

The cost of the additional 12 channels of multiplex equipment required by the Corps for the Dworshak project will be borne by the Corps.

(b) Kennewick-Teakean path

These additional facilities will be supplied by BPA.

(c) Teakean-Dworshak Switchyard path

BPA will provide for the RF equipment at Teakean. At Dworshak Switchyard, BPA will provide for the RF facing Teakean and all of the multiplex equipment.

(d) Dworshak Switchyard-Powerhouse path

At the Dworshak Switchyard the Corps will provide the RF facing the Powerhouse and BPA will provide multiplex equipment for 5 channels. At the Dworshak Powerhouse the Corps will provide the RF and multiplex equipment for 19 channels (McNary-12, Dworshak-5, Dittmer-2). At the Dworshak reflector site, in the Dworshak Switchyard-Powerhouse path the Corps will provide the reflector and site.

(e) Dittmer BPA System Control Center Terminal

BPA will provide multiplex equipment for 2 channels at the Dittmer System Control Center terminal.

(f) Teakean VHF Equipment

The cost of the additional VHF equipment required by the Corps will be borne by the Corps.

Exhibit 1

ESTIMATE OF INVESTMENT

	Total Investment	Corps Share of Investment	BPA 2/ Share of Investment
Ice Harbor	117,288 1/	117,288 1/	None
Lower Monumental	169,047 1/	119,710 1/	49,337 1/
Little Goose	161,222 1/	130,393 1/	30,829 1/
Lower Granite	334,400	154,100	180,300
Dworshak	503,000	201,900	301,100
TOTAL	1,284,957	723,391	561,566

1/ Actual Charges.
2/ Cost of cable installation between switchyard and powerhouse, if any, not included. Cost will be borne by BPA.

Exhibit 2 to
Attachment No. 11 to Exhibit B
of Contract No. 14-03-19250

DETAILED PROJECT AND OWNERSHIP DESCRIPTION
(John Day Project)

1. Project Description.

   (a) Provide a redundant RF microwave path from John Day Powerhouse to John Day Substation including an intervening passive reflector. Interconnect John Day Substation terminal with the existing "J" microwave system.

   (b) Provide multiplex channel equipment at John Day Powerhouse, John Day Substation, and at existing system microwave terminals for the following channels:

      (1) John Day Powerhouse to John Day Substation - 12 channels.

      (2) John Day Powerhouse to Dittmer Control Center - 10 channels.

      (3) John Day Powerhouse to Big Eddy Substation - 2 channels.

2. BPA shall procure, install, bear costs and retain ownership of:

   (a) The RF terminal and multiplex at John Day Substation.

   (b) Dittmer Control Center multiplex additions.

   (c) Big Eddy Substation multiplex additions.

3. BPA shall procure and install and the Corps shall bear costs and retain ownership of:

   (a) The RF terminal and multiplex at John Day Powerhouse.

   (b) The passive reflector in the path between John Day Powerhouse and John Day Substation.

4. Project Costs.

Total Investment	Corps Share of Investment	BPA Share of Investment
$211,772 1/	$134,478 1/	$77,294 1/

1/ Actual Charges.

5. This Exhibit supersedes page 1 of Letter Agreement, BPA Contract No. 14-03-69337, Supplement No. 1, dated November 10, 1966, to Corps, District Engineer, Walla Walla District, from Acting Assistant Administrator, BPA. Page 2 of said agreement relating to operation and maintenance arrangements have been superseded by Attachment 11 to which this Exhibit is appended. Maintenance will be performed per Section 7 of Attachment 11 except BPA will maintain Corps microwave equipment and passive reflector at John Day Powerhouse.

(AUTHENTICATED COPY)

Exhibit No. 3 to
Attachment No. 11 to Exhibit B of
Contract No. 14-03-19250
Revised: December 21, 1977

DETAILED PROJECT AND OWNERSHIP DESCRIPTION
(Shared Telecommunications, Libby Project)

1. Project Description.

   (a) Provide RF path from BPA's Blacktail microwave station to Libby Substation including:

      (1) Blacktail RF terminal connected to existing "Q" microwave system.

      (2) Libby Substation RF terminal including microwave maintenance channel terminations.

      (3) Intervening passive reflector at Zonolite Peak.

   (b) Provide RF path from Libby Substation to Libby Powerhouse including:

      (1) Libby Substation RF terminal.

      (2) Libby Powerhouse RF terminal including microwave maintenance channel terminations.

      (3) Intervening passive reflector near Libby Dam.

   (c) Provide multiplex channel equipment at Libby Substation, Libby Powerhouse, and existing Government microwave terminals for the following channels:

      (1) Libby Substation to existing BPA substations - 5 channels.

      (2) Libby Substation to Dittmer Control Center - 4 channels.

      (3) Libby Substation to Libby Powerhouse - 4 channels.

      (4) Libby Powerhouse to Dittmer Control Center - 2 channels.

      (5) Libby Powerhouse to Seattle District Office - 3 channels.

      (6) Libby Powerhouse to Albeni Falls Powerhouse - 2 channels.

2. BPA shall procure, install, bear the costs, and retain ownership of telecommunications facilities as follows:

   (a) Blacktail-Libby Substation RF path, including the intervening reflector.

   (b) Multiplex at Libby Substation.

(c) Multiplex at existing BPA substations.

(d) Supergroup multiplex interconnect for microwave systems at Kennewick microwave station.

(e) Multiplex at Dittmer Control Center.

(f) Multiplex at Albeni Falls Powerhouse.

3. BPA shall procure and install, and the Corps shall bear costs and retain ownership of telecommunications facilities as follows:

(a) Libby Substation to Libby Powerhouse RF path including the intervening reflector.

(b) Multiplex at Libby Powerhouse.

(c) Multiplex additions at BPA's Capitol Peak microwave station (for Seattle District Office channels).

4. The Corps shall procure, install, bear costs, and retain ownership of telecommunications facilities as follows:

(a) Interconnecting cable at Capitol Peak between BPA's microwave station and the Corps' radio station.

(b) Multiplex additions at the Corps' Capitol Peak radio station.

(c) Multiplex additions at the Seattle District Office.

5. Estimated Costs.

Corps	BPA	Total
$207,200	$417,200	$624,400

6. Maintenance to be performed per Section 7 of Attachment 11, except the Corps shall maintain the facilities at the Corps' Seattle District Office and at the Corps' Capitol Peak radio station, including the interconnecting cable at Capitol Peak.

APPROVED S/ RAY FOLEEN
Acting Administrator
Bonneville Power Administration

APPROVED S/ WESLEY E. PEEL
Division Engineer
North Pacific Division

Exhibit 4 to
Attachment No. 11 to Exhibit B
of Contract No. 14-03-19250

DETAILED PROJECT AND OWNERSHIP DESCRIPTION
(Shared Telecommunications; Control Centers and District Offices)

1. Project Description.

   (a) Provide redundant RF path from the Corps' Troutdale Computer Center to BPA's Biddle Butte microwave station, where it will connect to the existing "J" microwave station.

   (b) Provide non-redundant RF path from the Corps' Portland office in the Federal Building to BPA's Portland office building where it will connect to the existing "R" microwave system.

   (c) Provide multiplex channel equipment at the Corps' Troutdale Center, the Corps' Portland office, and existing Government microwave terminals for the following channels:

      (1) Troutdale Computer Center to Dittmer Control Center - 5 channels.

      (2) Troutdale Computer Center to Federal Building - 12 channels.

      (3) Troutdale Computer Center to Seattle District Office - 7 channels.

      (4) Troutdale Computer Center to Walla Walla District Office - 7 channels.

      (5) Troutdale Computer Center to Foster Dam - 1 channel.

      (6) Portland Federal Building to Dittmer Control Center - 1 channel.

2. BPA shall procure, install, bear the costs and retain ownership of telecommunications facilities as follows:

   (a) Biddle Butte RF terminal facing the Troutdale Center.

   (b) Dittmer Control Center multiplex additions.

   (c) Foster Dam multiplex additions.

3. BPA shall procure and install, and the Corps shall bear costs and retain ownership of:

   (a) Troutdale Computer Center RF terminal and multiplex.

   (b) Portland Federal Building RF terminal and multiplex.

   (c) BPA Portland building RF terminal and multiplex additions facing Portland Federal Building.

   (d) Kennewick microwave station "Q" system multiplex additions.

   (e) BPA Capitol Peak microwave station "N" system multiplex additions.

4. The Corps shall procure, install, bear the costs, and retain ownership of:

   (a) Kennewick microwave station, multiplex additions on Corps - Walla Walla microwave system.

   (b) Walla Walla District Office multiplex additions.

   (c) Corps' Capitol Peak radio station multiplex additions.

   (d) Seattle District Office multiplex additions.

5. Estimated Costs:

Corps Share of Costs	BPA Share of Costs	Total Costs
$280,000	$75,000	$355,000

6. Maintenance to be performed per Section 7 of Attachment 11 except the Corps shall maintain the facilities at the Corps Seattle District Office and at the Corps Capitol Peak radio station.

(AUTHENTICATED COPY)

DETAILED PROJECT AND OWNERSHIP DESCRIPTION

(Replacement of Microwave and Microwave System Related Equipment Owned by the Corps and Serving Corps Facilities)

1. Multiplex Replacements.

a. Bonneville shall design, purchase, and install programmable multiplex to replace obsolete Corps-owned low-density multiplex as follows:

(1) Dworshak Powerhouse - One Multiplex
(2) John Day Powerhouse - One Multiplex
(3) Kennewick Radio Station - Two Multiplex
(4) Libby Powerhouse - Three Multiplex
(5) Little Goose Substation - Four Multiplex
(6) Lower Granite Substation - Four Multiplex
(7) Lower Monumental Substation - Four Multiplex
(8) McNary Powerhouse - Two Multiplex
(9) Pomeroy Radio Station - One Multiplex
(10) Teakean Butte Radio Station - One Multiplex

b. Such design, purchase, and installation shall be performed by Bonneville in accordance with the schedule provided in Table 1.

c. The Corps shall pay Bonneville for the actual costs of such design, purchase, and installation. The Corps shall pay by check within 30 days after receipt of Form SF-1080 from Bonneville. The estimated costs are provided in Table 1.

d. The Corps shall retain ownership of the new multiplex.

2. Microwave Fault Alarm Replacements.

a. Bonneville shall design, purchase, and install fault alarm remotes to replace obsolete Corps-owned Noller microwave fault alarm remotes at the following installations:

(1) Dworshak Powerhouse
(2) Green-Wyatt Building
(3) Ice Harbor Powerhouse
(4) John Day Powerhouse
(5) Libby Powerhouse
(6) Little Goose Substation
(7) Lower Granite Substation
(8) Lower Monumental Substation
(9) McNary Powerhouse

b. Such design, purchase, and installation shall be performed by Bonneville in accordance with the schedule provided in Table 2.

c. The Corps shall pay Bonneville for the actual costs of such design, purchase, and installation. The Corps shall pay by check within 30 days after receipt of Form SF-1080 from Bonneville. The estimated costs are provided in Table 2.

d. The Corps shall retain ownership of the new microwave alarm remotes.

3. Microwave Radio Replacements.

a. Bonneville shall design, purchase, and install microwave radios and necessary baseband equipment to replace obsolete Corps-owned microwave radios as follows:

(1) Dworshak Substation-Dworshak Powerhouse - One Microwave Link
(2) BPA Headquarters Building to Green-Wyatt Building - One Microwave Link
(3) Kennewick to Ice Harbor Powerhouse - One Microwave Link
(4) John Day Powerhouse - One Microwave Terminal
(5) Libby Substation-Libby Powerhouse - One Microwave Link
(6) Little Goose Substation - One Microwave Terminal
(7) Lower Monumental Substation - One Microwave Terminal

b. Such design, purchase, and installation shall be performed by Bonneville in accordance with the schedule provided in Table 3.

c. The Corps shall pay Bonneville for the actual costs of such design, purchase, and installation. The Corps shall pay by check within 30 days after receipt of Form SF-1080 from Bonneville. The estimated costs are provided in Table 3.

d. The Corps shall retain ownership of the new microwave radios.

4. Design, Purchase, and Installation of Additional Facilities by Bonneville. Design, purchase, and installation of multiplex, microwave fault

alarm remotes, and microwave radios, the costs of which shall be assumed exclusively by Bonneville, shall not be addressed in this exhibit.

UNITED STATES OF AMERICA
Department of Energy

By /s/ Peter T. Johnson
Bonneville Power Administrator

Date of Execution JUN 29 1984

ACCEPTED:

UNITED STATES DEPARTMENT OF THE ARMY
Corps of Engineers

By /s/ James H. Higman
Division Engineer
North Pacific Division

Date 20 Jun 1984

(WP-PKJ-0298e)

Table 1 - Multiplex Replacements

Locations	Estimated Cost	Fiscal Year (FY) Scheduled for Replacement	Comments
Dworshak Powerhouse	$12,000	FY 83/84	Replace the Corps-owned, obsolete 34A multiplex, one channel.
John Day Powerhouse	$12,000	FY 83/84	Replace the Corps-owned, obsolete 34A multiplex, one channel.
Kennewick Radio Station	$ 8,000	FY 83/84	Two of Bonneville's obsolete 34A multiplex being replaced.
Libby Powerhouse	$17,000	FY 82	Completed under Bonneville Work Order 821-005; to be reimbursable-Corps-owned, 3 channels replaced.
Little Goose Substation	$12,000	FY 82	Corps-owned, replaced 4 multiplex channels.
Lower Granite Substation	$13,000	FY 82	Corps-owned, replaced 4 multiplex channels.
Lower Monumental Substation	$16,000	FY 83	Corps-owned, replacement of 4 multiplex channels.
McNary Powerhouse	$ 3,100	FY 83/84	Two of Bonneville's obsolete 34A multiplex being replaced.
Pomeroy Radio Station	$ 4,700	FY 83/84	One of three obsolete 34A multiplex being replaced.
Teakean Butte Radio Station	$ 3,200	FY 83/84	One of five multiplex being replaced.
Total	$101,000		

(WP-PKJ-0298e)

Table 2 - Microwave Fault Alarm Replacements

Locations	Estimated Cost	Fiscal Year (FY) Scheduled for Replacement	Comments
Dworshak Powerhouse		FY 83/84	Bonneville program to replace aged, obsolete Noller Fault Alarm System with new fault alarm system; requires concurrent replacement of Corps-owned fault alarm remotes.
Green-Wyatt Building		FY 83/84	"
Ice Harbor Powerhouse		FY 83/84	"
John Day Powerhouse		FY 83/84	"
Libby Powerhouse		FY 83/84	"
Little Goose Substation		FY 83/84	"
Lower Granite Substation		FY 83/84	"
Lower Monumental Substation		FY 83/84	"
McNary Powerhouse		FY 83/84	"
	Total $69,000		

(WP-PKJ-0298e)

Table 3 - Microwave Radio Replacements

Locations	Estimated Cost	Fiscal Year (FY) Scheduled for Replacement	Comments
Dworshak Substation - Dworshak Dam	$120,000	FY 86/87	GE TRS696 radio no longer manufactured.
BPA Headquarters Bldg. - Green Wyatt Bldg.	$120,000	FY 84/85	Frequency in exclusive band, GTE Lenkurt 76C1 radio no longer manufactured.
Kennewick - Ice Harbor Powerhouse	$120,000	FY 85/86	Frequency in exclusive band, GTE Lenkurt 76C1 radio no longer manufactured.
John Day Dam	$60,000	FY 88/89	GTE Lenkurt 76C1 radio no longer manufactured.
Libby Substation-Libby Dam	$120,000	FY 86/87	GE TRS696 radio no longer manufactured.
Little Goose Substation	$60,000	FY 85/86	Frequency in exclusive band; GTE Lenkurt 76C1 radio no longer manufactured.
Lower Monumental Substation	$ 60,000	FY 85/86	GTE Lenkurt 76C1 radio no longer manufactured.
	$660,000		

(WP-PKJ-0298e)

AUTHENTICATED COPY

Attachment No. 12 to Exhibit B of
Contract No. 14-03-19250
Effective Date: December 1, 1974

OPERATING ARRANGEMENT
(Provisional Draft of Reservoirs)

SUBJECT: Interim Arrangement and Procedures Relating to the Provisional Operation of Dworshak Reservoir Below Energy Content Curve During 1974-75

1. This Operating Arrangement is made pursuant to paragraph 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer

2. General: The North Pacific Division (NPD), Corps of Engineers, and the Bonneville Power Administration (BPA) have agreed upon arrangements and procedures for the provisional operation of Dworshak Reservoir below the Energy Content Curve during winter 1974-75. Such arrangements will recognize the principle of multipurpose use of water and, at the same time, permit the BPA to serve the nonfirm requirements of its industrial customers for an interim period from 1 December 1974 until the January 1975 runoff forecasts are completed.

3. Arrangements and Procedures:

   A. Provisional energy, for which provisional drafts are made, will be as defined in Section 2(cc) of the PNW Coordination Agreement, except as qualified below.

   B. Dworshak Reservoir will not be drafted for provisional energy in an amount that cannot be replaced with equivalent water by 30 June 1975 nor below the elevation from which the reservoir can be refilled with 95 percent assurance while passing minimum release.

   C. If required, a timely schedule of provisional energy return (in equivalent water) shall be instituted. Such return shall be completed no later than 30 June 1975. The schedule for return of energy will be a function of the size of the outstanding provisional energy account and the rate at which energy can be returned.

   D. To assure that outflow from Dworshak is reduced to minimum early enough to enable fill to the 30 June content it would have reached without provisional draft, the following procedure using the Variable Energy Content Curve (VECC) results will be implemented:

      (1) If the 1 January VECC determination does not lower the base ECC by the amount of the provisional draft, the industries will submit their individual plans for replacement during the period 10 February through 30 June of the amount of provisional energy not covered by lowering the ECC.

(2) If the 1 February VECC determination does not lower the base ECC by the amount of the provisional draft, the plans developed in 1 above for replacement indicated by the 1 February determination will be implemented and Dworshak outflow will be reduced to minimum. Minimum outflow averaging 2,000 cfs at Dworshak will continue until the reservoir reaches the lower of its VECC or its proportional draft level.

(3) This process will continue each month until the reservoir recovers to the lower of its VECC or its proportional draft level.

E. Written agreement for the return of provisional energy between BPA and provisional energy customers shall be accomplished prior to any substantial draft of provisional energy.

F. Notification of load curtailment to provisional energy customers to satisfy the provisions of C. above shall be issued by BPA. Such notice will reflect previous written agreement and shall recognize that load curtailment is based on total system requirements.

G. Deliveries of provisional energy will be made consistent with established multipurpose water resource management practices, and will not preclude the use of the reservoir for nonpower purposes. Before initiating a request for provisional energy drafts, consideration will be made for but not limited to future probability of spill, at-site or in the system; head losses; the existing load-resource balance; and available alternative sources of reasonable cost energy.

H. The request for the return of provisional energy, should it be required, shall be based on the standard water management studies of the Corps of Engineers.

4. This Attachment No. 12 will be replaced with a new Attachment No. 12 when final arrangements and procedures relating to provisional draft from reservoirs has been agreed between the parties.

APPROVED (SGD) Donald Paul Hodel
Administrator
Bonneville Power Administration

APPROVED (SGD) D. E. Olson
for Division Engineer
North Pacific Division

(AUTHENTICATED COPY)

Attachment No. 12 to Exhibit B
of Contract No. 14-03-19250
Effective Date: Dec. 29, 1976

Supersedes Attachment No. 12
of December 1, 1974

OPERATING ARRANGEMENT
(Provisional Draft of Reservoirs)

SUBJECT: Interim Arrangement and Procedures Relating to the Provisional Operation of the Dworshak and Libby Reservoirs Below Energy Content Curves During the 1976-77 Operating Year

1. The Operating Arrangement is made pursuant to paragraph 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer.

2. General: The North Pacific Division (NPD), Corps of Engineers, and the Bonneville Power Administration (BPA) have agreed upon arrangements and procedures for the provisional operation of Dworshak and Libby Reservoirs below Energy Content Curves during operating year 1976-77. These arrangements recognize multipurpose use of water and permit BPA to supply non-firm power to its industrial customers on a provisional basis.

3. Arrangements and Procedures:

a. Provisional energy, for which provisional drafts are made, will be as defined in Section 2 (cc) of the PNW Coordination Agreement, except as qualified below.

b. Delivery of provisional energy from either reservoir will be limited to that amount which can be returned by 31 July 1977 but not to exceed $.560 \times 10^9$ kwh developed thru at site and downstream Federal system head.

c. Unless otherwise agreed to by the Administrator and the Division Engineer, BPA will institute the timely return of provisional energy so as to insure that each reservoir from which provisional energy was delivered, will refill to the same elevation as it would have reached without provisional draft.

d. BPA will not market surplus energy outside the Pacific Northwest unless one of the following two conditions is satisfied at each reservoir from which water has been drafted on a provisional basis:

(AUTHENTICATED COPY)

Attachment No. 13 to Exhibit B of
Contract No. 14-03-19250
Effective Date: January 1, 1978

OPERATING ARRANGEMENT
(Joint Planning of Hydromet Data Acquisition Facilities)

SUBJECT: Principles and Procedures Relating to the Joint Planning of Hydromet Facilities

1. This Operating Arrangement is made pursuant to Section 6 of the Memorandum of Understanding, Contract No. 14-03-19250, between the Administrator and the Division Engineer.

2. Reference Agreement. The Corps of Engineers and Bonneville Power Administration are, with certain other Federal agencies, signatories to the Interagency Memorandum of Understanding for Task Force on Operational Hydromet Data Management, Contract No. 14-03-99114, dated 11 June 1970.

3. General. Consistent with Interagency Agreement, Contract No. 14-03-99114, the Corps of Engineers, North Pacific Division (NPD), and Bonneville Power Administration (BPA), agree to coordinate plans for their respective hydromet data acquisition systems in order to prevent unnecessary duplication of facilities, to gain the economics of multiple use of existing and proposed facilities consistent with individual agency responsibilities, and to promote other benefits identified in Contract No. 14-03-99114.

4. Specific Agreements. Details of agreement relating to respective areas of responsibility with regard to specific hydromet data acquisition facilities shall be documented as exhibits to this Operating Arrangement,

(1) The reservoir is discharging its non-power minimum discharge or

(2) The reservoir can be refilled by 31 July with 95 percent confidence.

e. Any of the above arrangements and procedures may be modified at any time by mutual agreement between the Division Engineer and the Administrator.

4. This Attachment No. 12 will be replaced with a new Attachment No. 12 when final arrangements and procedures relating to provisional draft from reservoirs has been agreed between the parties.

APPROVED S/ DONALD PAUL HODEL
Administrator
Bonneville Power Administration

APPROVED S/ WESLEY E. PEEL
Division Engineer
North Pacific Division

except that details of agreement regarding joint use of microwave channels for hydromet purposes shall be documented as exhibits to Attachment No. 11 to Exhibit B of Contract No. 14-03-19250.

5. At the BPA sites where the Corps is to install, operate, and maintain Corps equipment, BPA shall grant to the Corps appropriate real estate permits, including rights of access. In these cases where BPA holds the land involved by less than fee ownership, the Corps will, in addition to the BPA permit, obtain from the Government agency and/or others involved, any required land-use instruments.

APPROVED S/ STERLING MUNRO
Administrator
Bonneville Power Administrator

APPROVED S/ WESLEY E. PEEL
Division Engineer
North Pacific Division

Exhibit No. 1 to
Attachment No. 13 to Exhibit B of
Contract No. 14-03-19250
Effective Date: January 1, 1978

WILLAMETTE AREA HYDROMET SYSTEM
(Area Responsibility and Shared Facilities)

1. Coordination Responsibility. In accordance with Interagency Agreement, Contract No. 14-03-99114, Exhibit B, revised 24 September 1970, the Corps is designated responsible for coordination of the automatic hydromet network in the Willamette area.

2. Corps Remote Hydromet Stations. In conformance with the designated responsibility, item 1, and to promote integrated hydromet data acquisition in the Willamette area, the Corps shall provide, own, operate, and maintain the hydromet remote reporting stations in this area, including, among others, stations at Government Camp, Lee's Camp, Brightwood, Summit, and Haskin's Dam.

3. BPA Removal of Hydromet Equipment. In conjunction with Corps action, item 2, BPA shall, at BPA expense, remove BPA hydromet remote reporting stations from Government Camp, Lee's Camp, Brightwood, and Summit, as well as associated interface to microwave terminal units from West Portland and Prospect Hill radio stations for other use on BPA's system. BPA shall abandon its plans for a new remote station at Haskin's Dam.

4. Corps Hydromet Equipment at BPA Radio Stations. As required to establish the Willamette Area Hydromet Network, the Corps shall provide, own, operate, and maintain radio equipment to be installed at BPA radio

stations identified below for interface with microwave channel facilities covered in Exhibit 4 to Attachment No. 11 to Exhibit B of Contract No. 14-03-19250.

BPA shall provide rack space, tower antenna mounting space, and a-c power for the following Corps equipment at BPA stations:

(a) West Portland - 1 vhf radio and rack, 1 antenna; battery, a-c charger

(b) Wolf Mountain - 1 vhf radio and rack, 1 antenna; battery, a-c charger

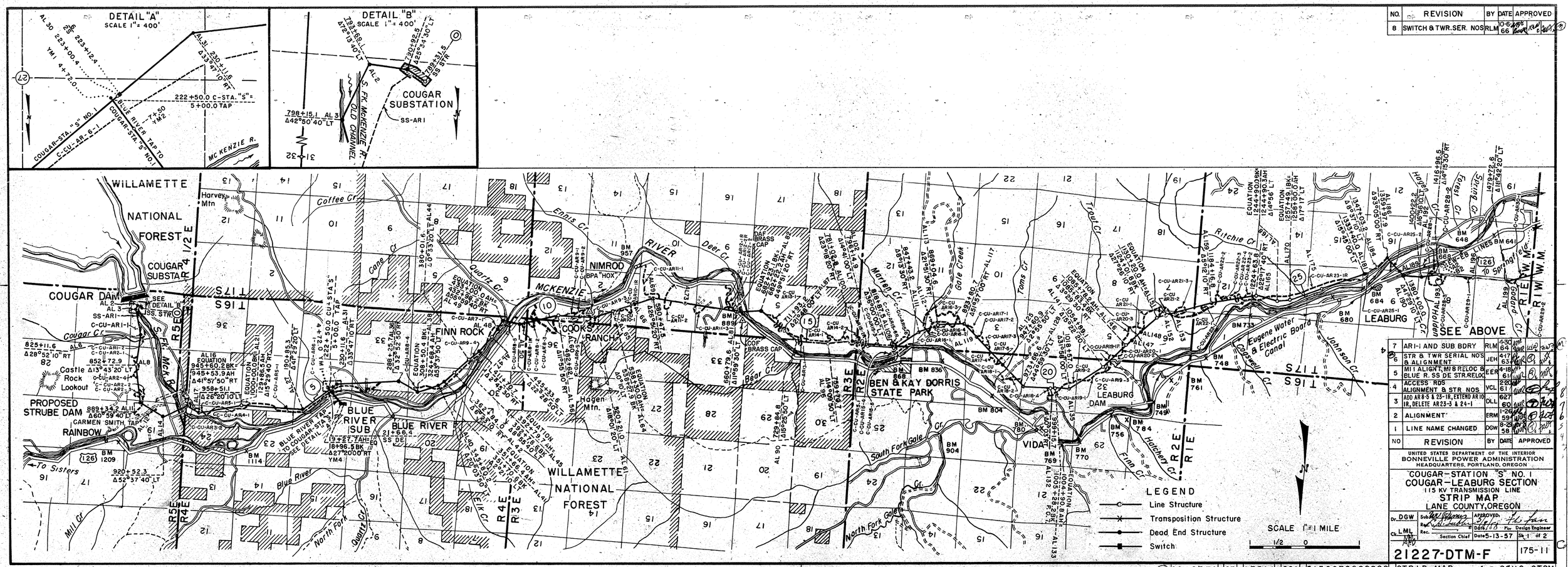
(c) Prospect Hill - 1 vhf radio and rack, 1 antenna; battery, a-c charger

(d) Coburg - 1 vhf radio and rack, 1 antenna; battery, a-c charger

(e) Horse Rock - 1 vhf radio and rack, 1 antenna; battery, a-c charger

5. Special. Should the Corps choose to have the maintenance of Corps radio equipment at BPA radio stations carried out by private contractor, it is BPA practice that the contractor be accompanied by a Government representative at Corps expense.

6. Costs of Coordination. Each party shall bear the costs it incurs in coordinating the joint aspects of the Willamette Valley Hydromet System.



NO.	REVISION	BY	DATE	APPROVED
8	SWITCH & TWR.SER. NOS	RLM	10-5-66	

NO	REVISION	BY	DATE	APPROVED
7	AR1-1 AND SUB BDRY	RLM	4-30-64	
6	STR & TWR SERIAL NO'S & ALIGNMENT	JEH	8-17-63	
5	MI 1 ALIGN'T, MI 8 RELOC & BLUE R. SS DE STR. RELOC	EER	4-18-61	
4	ACCESS RDS ALIGNMENT & STR NOS.	VCL	6-30-60	
3	ADD AR 8-5 & 23-1R, EXTEND AR 10 1R, DELETE AR 23-3 & 24-1	DLL	6-27-60	
2	ALIGNMENT	ERM	1-26-59	
1	LINE NAME CHANGED	DGW	8-29-58	

UNITED STATES DEPARTMENT OF THE INTERIOR
BONNEVILLE POWER ADMINISTRATION
HEADQUARTERS, PORTLAND, OREGON

COUGAR-STATION "S" NO. 1
COUGAR-LEABURG SECTION
115 KV TRANSMISSION LINE
STRIP MAP
LANE COUNTY, OREGON

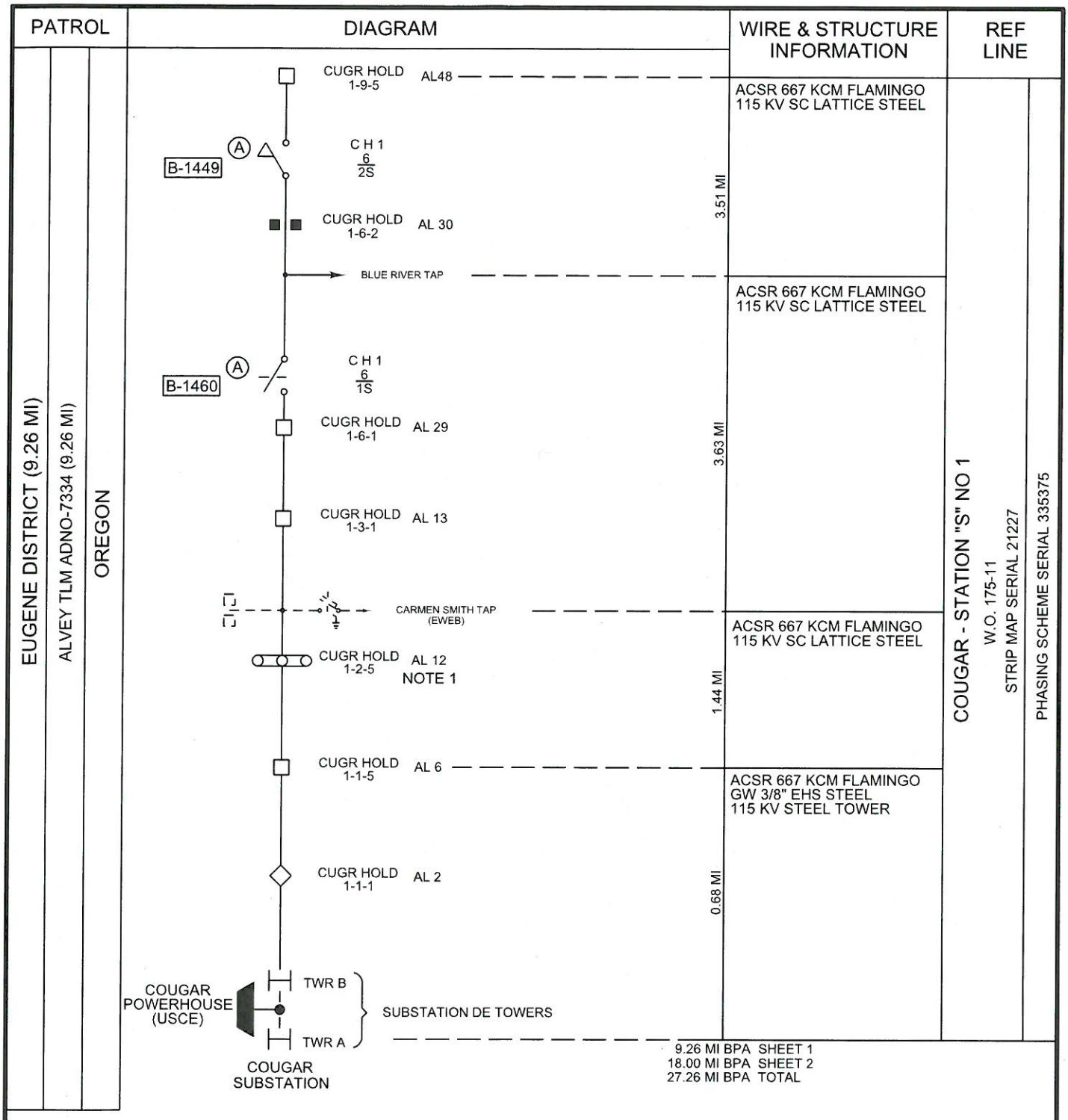
Dr. DGW | Ck. LML | Sub. | Reg. | Rec. | APPROVED: For Design Engineer | Section Chief | Date 5-13-57 | Sh. 1 of 2

21227-DTM-F

175-11

M 0212270 08 17511 001 5136078000000 STRIP MAP 1 C QUG-STSM


LEGEND
Line Tower
Transposition Tower
Dead End Tower.
WILLAMETTE MERIDIAN
WALTERVILLE
McKENZIE
DEERHORN
CAMP CR. CEMETERY
CEDAR FLAT
HENDRICKS BRIDGE
THURSTON
MAGNESS
MOHAWK JCT.
SPRINGFIELD JCT.
SPRINGFIELD SUB
SPRINGFIELD
EUGENE
Kelley Butte
Skinner Butte
HENDRICKS (R.R. STATION)
HAYDEN BRIDGE
WILLAMETTE
RIVER
DANEBO
EUGENE YARD
BURMA
To Junction City
WILLAKENZIE SUB (STA "S" - E.W. & E.B.)
WILLAKENZIE
ARMITAGE (R.R. STATION)
Gillespie Butte
CHESTNUT
LEABURG
To Nimrod
Eugene Water & Electric Board Canal
Walterville Canal
Coburg Ridge
MOHAWK
LEBANON GOSHEN LINE
GOSHEN-SPRINGFIELD LINE
To Goshen
T17S
T16S
T18S
R1W
R2W
R3W
R4W
2 TWR NOS. & ADD SSDE AT STA 2385+20± RLM 10-13-66
E.W. & E.B. LINES, RELOC. TOWN OF WALTERVILLE, & WILLAKENZIE DE STA. JEH EER 8-2 61
NO REVISION BY DATE APPROVED
UNITED STATES DEPARTMENT OF THE INTERIOR
BONNEVILLE POWER ADMINISTRATION
HEADQUARTERS, PORTLAND, OREGON
COUGAR-STATION "S" NO. 1
LEABURG-STATION "S" SECTION
115 KV TRANSMISSION LINE
STRIP MAP
LANE COUNTY, OREGON
SCALE 1"=1 MILE
Date 1-24-58 Sh 2 of 2
21228-DTM-F 175-11
21228 2 17511 2 513607800 STRIP MAP 1 COUG STSM



NOTES:

1. AL 12 IS A 3 POLE TUBULAR STEEL STRUCTURE

NO.			BY	DATE	APPROVED
1	UPDATED CARMEN TAP LINE NAME		GLL	05/01/18	GVA
0	THIS SHEET CREATED FROM COUGAR-THURSTON 108825-1 BECAUSE OF LINE SPLIT FOR NEW HOLDEN SUBSTATION		GLL	02/07/18	
	420013	COMPUTER REVISION ONLY			

C=CONTRACT CONSTR., FA=FORCE ACCOUNT CONSTR., R=RECORD. FILE NAME: 335344-1-1

APPROVED	
COMPILED	GLL
DRAWN	GLL
CHECKED	NDM
CHECKED	
APPROVED	GAV
DATE	02/07/18

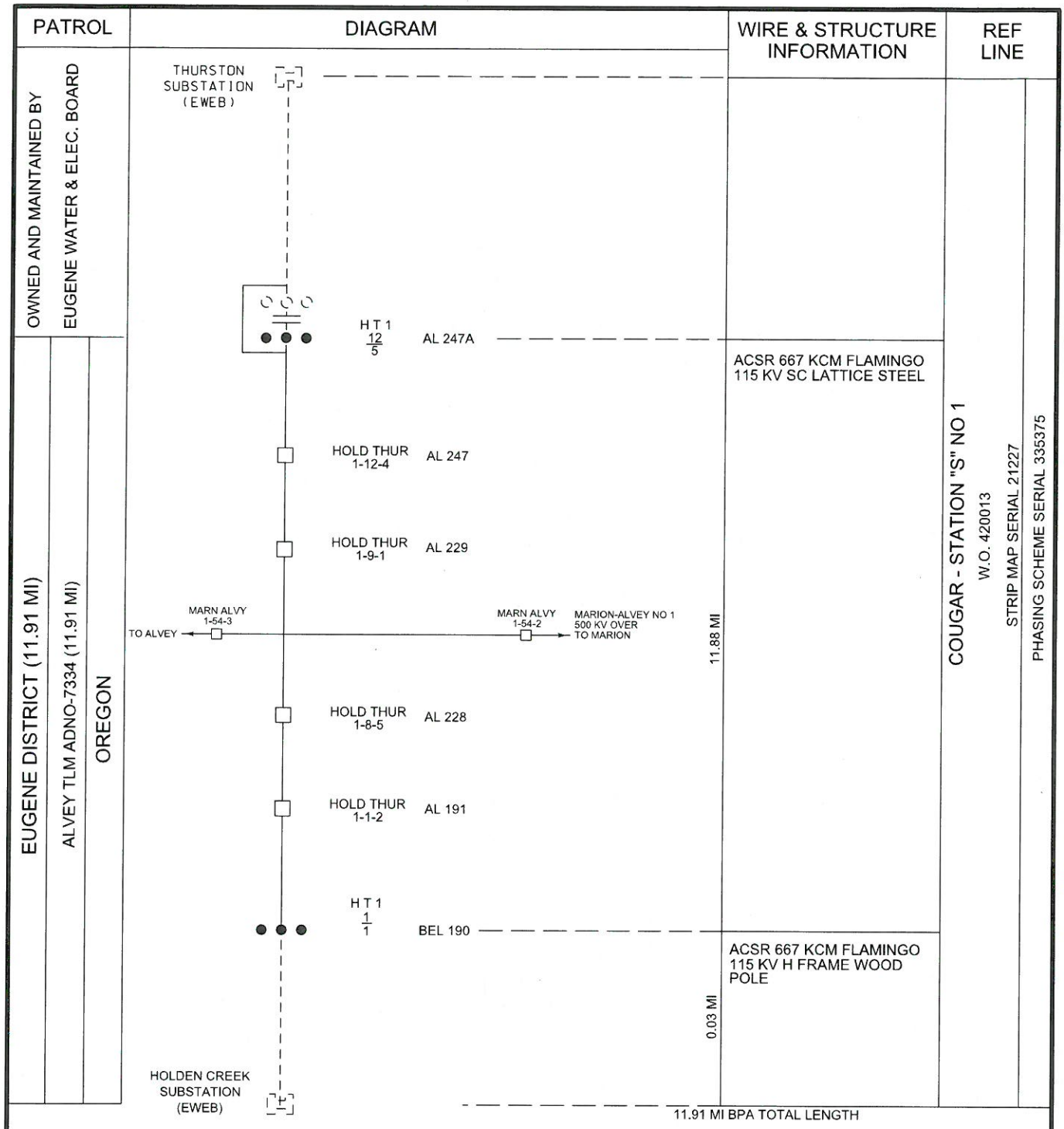
UNITED STATES DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
HEADQUARTERS, PORTLAND, OREGON

TRANSMISSION LINE ONE-LINE DIAGRAM

COUGAR - HOLDEN CREEK NO 1

115 KV CUGR-HOLD-1

SERIAL	SOURCE	SIZE	SHEET	REVISION
335344	LBL	ANSI A	1 OF 2	1



NO.				BY	DATE	APPROVED
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	420013	COMPUTER	REVISION ONLY			

C=CONTRACT CONSTR., FA=FORCE ACCOUNT CONSTR., R=RECORD. FILE NAME: 335344-2-0

APPROVED	
COMPILED	GLL
DRAWN	GLL
CHECKED	NDM
CHECKED	
APPROVED	GVA
DATE	02/07/18

UNITED STATES DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
HEADQUARTERS. PORTLAND. OREGON

TRANSMISSION LINE ONE-LINE DIAGRAM

HOLDEN CREEK - THURSTON NO 1

115 KV HOLD-THUR-1

SERIAL	SOURCE	SIZE	SHEET	REVISION
335345	LBL	ANSI A	1 OF 1	0

NORTH ARROWS INDICATE ORIENTATION OF TERMINAL STRUCTURES

COUGAR POWERHOUSE (USCE)

C B A

COUGAR SWITCHYARD

C - LT
B - MID
A - RT

SS DE TWR A

1

2.12 MI

SS DE TWR B

1-2-5 AL 12

CARMEN SMITH TAP (EWEB)

2

3.63 MI

1-3-1 AL 13

BLRIT-CUHO-1 1/1 YM 1 SEE DWG 155901

1-6-1 AL 29

A B C

BLRIT-CUHO-1 1/2 YM 2

3

3.51 MI

1-6-2 AL 30

1-9-5 AL 48

PHASING SHOWN IN PLAN NO TRANSPOSITIONS REQUIRED

17.91 MI

27/9 AL 189

27/10 BEK 190

A - TOP
B - MID
C - BOT

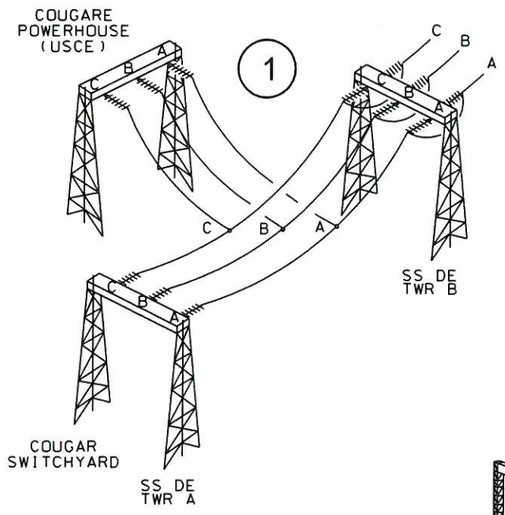
HOLDEN CREEK SUBSTATION (EWEB)

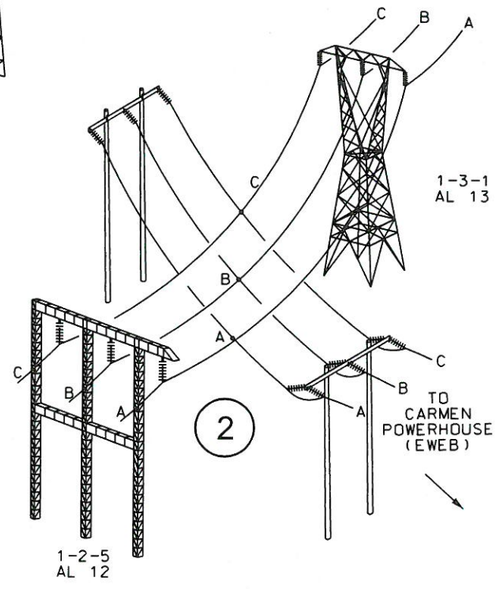
4

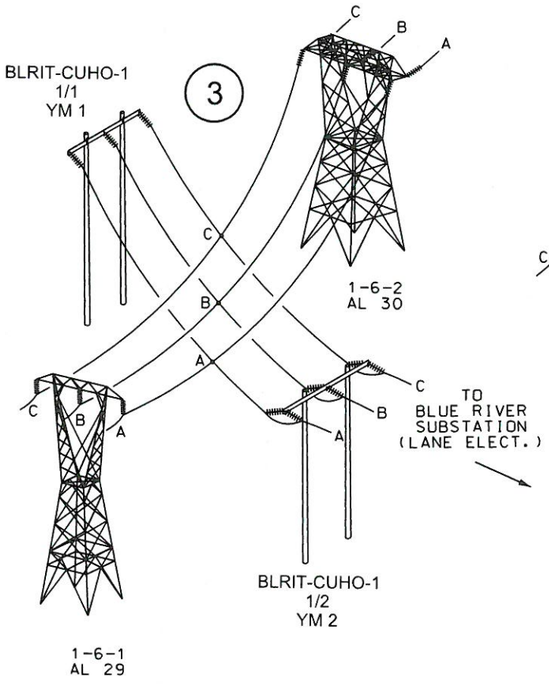
0.05 MI

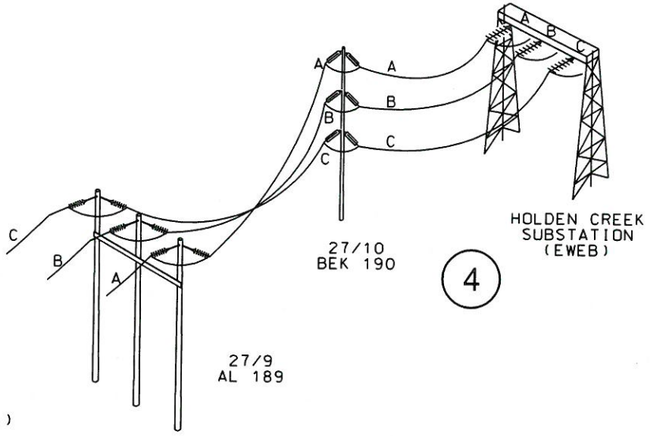
0.03 MI

NORTH ARROWS INDICATE ORIENTATION OF TERMINAL STRUCTURES









LINE LENGTH = 27.25 MI

NO.	WD 420013	COMPUTER REVISION ONLY	BY	DATE	APPROVED
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0		THIS SHEET CREATED FROM COUGAR-THURSTON 109064-1 BECAUSE OF LINE SPLIT FOR NEW HOLDEN SUBSTATION	GLL	02/07/18	AOB/EEF

C=CONTRACT CONSTR.. FA=FORCE ACCOUNT CONSTR.. R=RECORD. FILE NAME: 335375-1-1

APPROVED

COMPILED GLL
DRAWN GLL
CHECKED
ELEC EFFECT AOB
APPROVED EEF
DATE 02/07/18

UNITED STATES DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
HEADQUARTERS. PORTLAND. OREGON

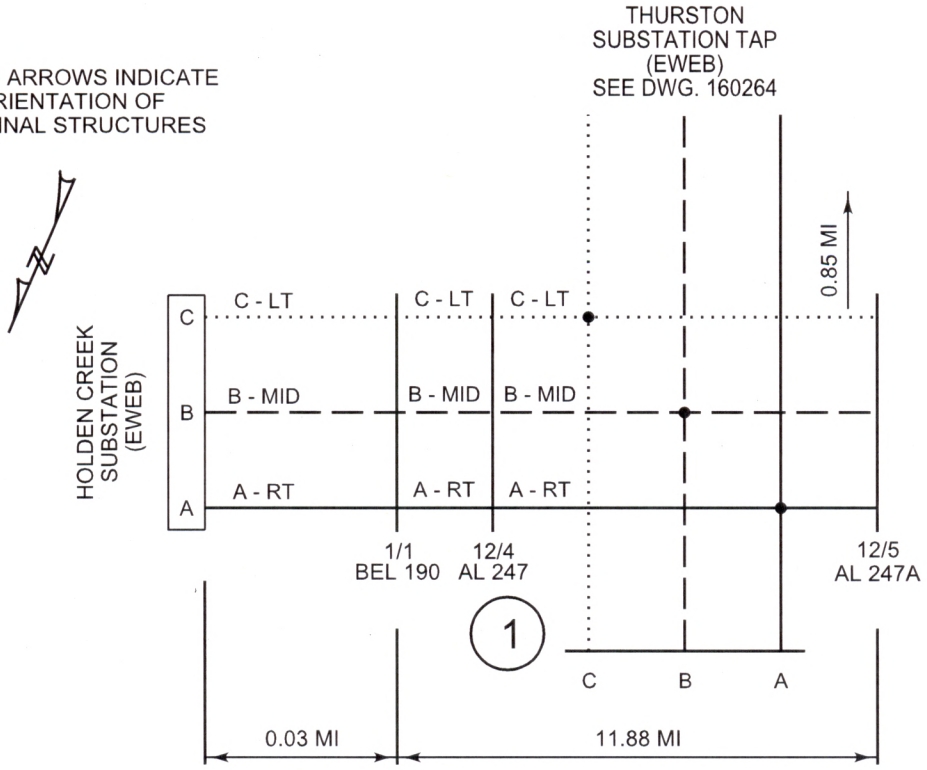
TRANSMISSION LINE PHASING SCHEME

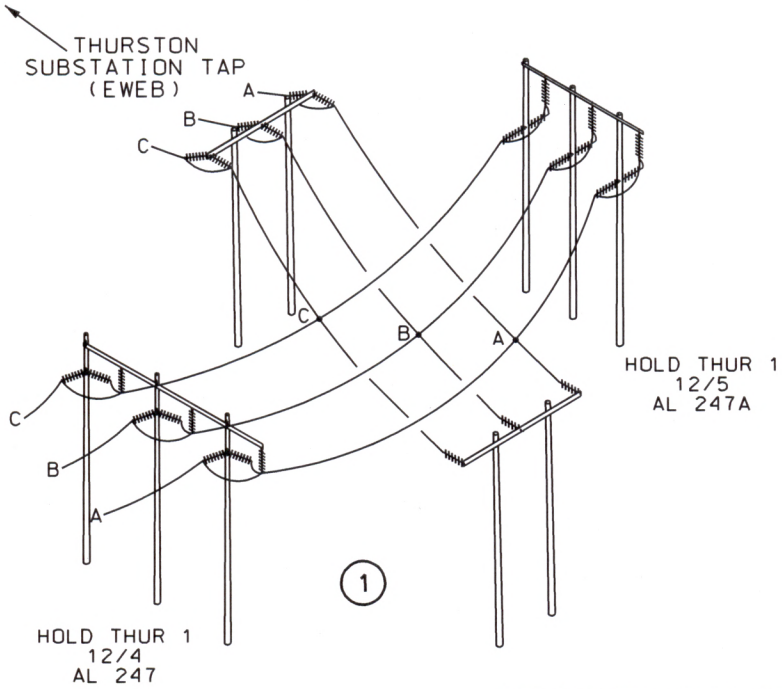
COUGAR- HOLDEN CREEK NO. 1

115 KV CUGR-HOLD-1

SERIAL	SOURCE	SIZE	SHEET	REVISION
335374	LBL	ANSI B	1 OF 1	1

NORTH ARROWS INDICATE ORIENTATION OF TERMINAL STRUCTURES





BPA LINE LENGTH = 11.91 MI
EWEB LINE LENGTH = 0.85 MI
TOTAL LENGTH = 12.76 MI

NO.		WO			BY	DATE	APPROVED
0	THIS SHEET CREATED FROM COUGAR-THURSTON 109064-1 BECAUSE OF LINE SPLIT FOR NEW HOLDEN SUBSTATION				GLL	02/07/18	
		420013	COMPUTER	REVISION ONLY			

C=CONTRACT CONSTR., FA=FORCE ACCOUNT CONSTR., R=RECORD. FILE NAME: 335375-1-0

APPROVED

COMPILED GLL

DRAWN GLL

CHECKED

ELEC EFFECT AQB

APPROVED

DATE 02/07/18

UNITED STATES DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
HEADQUARTERS. PORTLAND. OREGON

TRANSMISSION LINE PHASING SCHEME

HOLDEN CREEK-THURSTON NO. 1

115 KV HOLD-THUR-1

SERIAL	SOURCE	SIZE	SHEET	REVISION
335375	LBL	ANSI A	1 OF 1	0

DOE F 1325.8e Electronic Form Approved by Forms Mgmt. 04/19/2006
(08-89)

United States Government **Department of Energy**

Bonneville Power Administration

memorandum

DATE: May 10, 2018

REPLY TO ATTN OF: TELP-TPP-3

SUBJECT: Cougar-Holden Creek No 1

TO: See Distribution

The addition of Holden Creek Substation into BPA's existing Cougar-Thurston No 1 transmission line results in two new operating names. The new operating name between Cougar Substation and Holden Creek Substation (EWEB) will be Cougar-Holden Creek No 1 at an operating voltage of 115 kV.

This memorandum documents the naming of **Cougar-Holden Creek No 1** operating at 115 kV. The reference codes based on the four letter station codes, as it will appear on the One-Line Diagram, will be CUGR-HOLD-1.

A new Transmission One Line Diagram has been created. All operating and maintenance records shall be revised accordingly.

(b) (6)

Gabriela Alvarez
Transmission Facilities Naming Committee

DOE F 1325.8e Electronic Form Approved by Forms Mgmt. 04/19/2006
(08-89)

United States Government **Department of Energy**

Bonneville Power Administration

memorandum

DATE: May 10, 2018

REPLY TO ATTN OF: TELP-TPP-3

SUBJECT: Holden Creek-Thurston No 1

TO: See Distribution

The addition of Holden Creek Substation into BPA's existing Cougar-Thurston No 1 transmission line results in two new operating names. The new operating name between Holden Creek Substation (EWEB) and Thurston Substation will be Holden Creek-Thurston No 1 at an operating voltage of 115 kV.

This memorandum documents the naming of **Holden Creek-Thurston No 1** operating at 115 kV. The reference codes based on the four letter station codes, as it will appear on the One-Line Diagram, will be HOLD-THUR-1.

A new Transmission One Line Diagram has been created. All operating and maintenance records shall be revised accordingly.

(b) (6) [redacted]

Gabriela Alvarez
Transmission Facilities Naming Committee