92-035-27

UTAH POWER & LIGHT COMPANY

1407 WEST NORTH TEMPLE STREET
SALT LAKE CITY, UTAH 84140

LEGAL DEPARTMENT
THOMAS W. FORSGREN
ASSISTANT VICE PRESIDENT
ASSISTANT CORPORATE SECRETARY
ATTORNEY AT LAW
801-220-4261

RECEIVED
'89 JAN -9 P4:37
UTAH PUBLIC
SERVICE COMMISSION

January 9, 1989

Chairman Brian T. Stewart
Public Service Commission of Utah
Heber M. Wells Building
160 East 300 South
Fourth Floor
Salt Lake City, Utah 84111

Dear Chairman Stewart:

Transmitted herewith please find a copy of the notice of adoption of rates, rules, classifications, regulations, tariffs, contracts, notices, authorities, powers and other instruments of Utah Power & Light Company, a Division of PacifiCorp, an Oregon Corporation.

If you have questions or wish to discuss the same, please contact me at your convenience.

Kindest personal regards,

THOMAS W. FORSGREN

TWF:hlr

<u>UTAH POWER & LIGHT COMPANY</u>
<u>NOTICE OF ADOPTION OF TARIFFS AND OTHER INSTRUMENTS</u>

UTAH POWER & LIGHT COMPANY, a division of PacifiCorp, an Oregon Corporation, hereby adopts, ratifies and makes its own in every respect, as if the same had been originally filed by it, all rates, rules, classifications, regulations, tariffs, contracts, notices, authorities, powers and other instruments of UTAH POWER & LIGHT COMPANY on file with the Public Service Commission of Utah and in effect as of January 9, 1989, the effective date of the merger of PACIFICORP, a Maine corporation, and UTAH POWER & LIGHT COMPANY, a Utah corporation, with and into PC/UP&L MERGING CORP., an Oregon corporation (renamed PacifiCorp). By this notice, it also adopts and ratifies all supplements and amendments to any of the above instruments which have heretofore been filed with the Public Service Commission of Utah.

Executed this 9th day of January, 1989.

UTAH POWER & LIGHT COMPANY,
a Division of PacifiCorp, an
Oregon Corporation

By ________________________
F. N. Davis
President and Chief
Executive Officer

utah power & LIGHT COMPANY
1407 West North Temple
Salt Lake City, Utah 84140
(801) 220-4242

F. N. DAVIS
President and
Chief Executive Officer

RECEIVED
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UTAH PUBLIC
SERVICE COMMISSION

January 9, 1989

Chairman Brian T. Stewart
Public Service Commission of Utah
Heber M. Wells Building
160 East 300 South
Fourth Floor
Salt Lake City, Utah 84111

Dear Chairman Stewart:

The merger of PacifiCorp and Utah Power & Light Company with and into PC/UP&L Merging Corp. became effective today, January 9, 1989. The name of PC/UP&L Merging Corp. has been changed to PacifiCorp, an Oregon corporation.

The new PacifiCorp will provide electric utility service in areas previously served by Pacific Power & Light Company through its Pacific Power & Light Company division and will provide electric utility service in areas previously served by Utah Power & Light Company through its Utah Power & Light Company division. These names will continue to be used for regulatory matters relating to the operating divisions. Matters relating to the merged company as a whole, such as securities applications, will be handled under the name PacifiCorp.

Thank you for your cooperation throughout the long merger approval process.

Very truly yours,

F. N. DAVIS

FND:hlr

UTAH POWER & LIGHT COMPANY

1407 WEST NORTH TEMPLE STREET

SALT LAKE CITY, UTAH 84140

RECEIVED

'89 JAN -9 P4:37

UTAH PUBLIC
SERVICE COMMISSION

LEGAL DEPARTMENT
THOMAS W. FORSGREN
ASSISTANT VICE PRESIDENT
ASSISTANT CORPORATE SECRETARY
ATTORNEY AT LAW
801-220-4261

January 9, 1989

Chairman Brian T. Stewart
Public Service Commission of Utah
Heber M. Wells Building
160 East 300 South
Fourth Floor
Salt Lake City, Utah 84111

Dear Chairman Stewart:

Transmitted herewith for your review and information please find a copy of the Company's Compliance Filing in FERC Docket No. EC88-2-000.

Very truly yours,

Tom Forsgren

Thomas W. Forsgren

TWF/jj

Enclosure

It is respectfully requested that the Notice of Announcement of Remaining Existing Capacity be published in the Federal Register with the understanding that the 90-day period for utilities seeking status as Qualifying Entities (established on page 41 (Slip) of Opinion No. 318) will commence to run on the date of such publication.

Applicants believe that there is a substantial likelihood that there will not be an oversubscription of requests for access to Remaining Existing Capacity in regard to most, if not all points of delivery. If there is adequate Remaining Existing Capacity to respond to all wheeling requests received during the 90-day reservation period, many issues and potential disputes regarding the determination of Remaining Existing Capacity and the operation of allocation "tiers" will be rendered moot. In order to avoid what may well prove to be unnecessary debate on the technical merits of this Compliance Filing, and in order to facilitate the prompt implementation of the wheeling provisions of Opinion No. 318, it is respectfully suggested that the Commission not require comment on this Compliance Filing until after the 90-day reservation period has elapsed. At that time, the Merged Company will be able to advise the Commission and the parties of the extent of any oversubscription. Disputed issues, if any, can then be better identified.

The Merged Company stands willing to immediately enter into negotiations to provide wheeling service to utilities pending the Commission's review of Applicants' Compliance Filing. Such service would be provided at negotiated rates, subject to subsequent adjustment and/or refund based upon the disposition of a rate filing to be made under Section 205 of the Federal Power Act during the first half of 1989, and subject to the terms and conditions of the Compliance Filing as ultimately approved by the Commission.

It is expected that the effective date of the merger of Utah Power & Light Company and PacifiCorp with and into PC/UP&L Merging Corp. (to be renamed PacifiCorp) will occur on January 9, 1989.

Very truly yours,

George M. Galloway

GMG:dc
Enclosures
cc w/encls: Parties of Record

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Utah Power & Light Company PacifiCorp PC/UP&L Merging Corp.	)))	Docket No. EC88-2-000

<u>Statement of Acceptance</u>

Utah Power & Light Company, PacifiCorp and PC/UP&L Merging Corp. hereby accept the terms and conditions of Federal Energy Regulatory Commission Opinion No. 318 entered in this Docket.

Dated: January 5, 1989.

Utah Power & Light Company

By ____________________

PacifiCorp

see attached signed counterpart

By ____________________

PC/UP&L Merging Corp.

see attached signed counterpart

By ____________________

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Utah Power & Light Company PacifiCorp PC/UP&L Merging Corp.	)))	Docket No. EC88-2-000

Statement of Acceptance

Utah Power & Light Company, PacifiCorp and PC/UP&L Merging Corp. hereby accept the terms and conditions of Federal Energy Regulatory Commission Opinion No. 318 entered in this Docket.

Dated: January 5, 1989.

Utah Power & Light Company

see attached signed counterpart

By ______________________

PacifiCorp

By ______________________

PC/UP&L Merging Corp.

By ______________________

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Utah Power & Light Company, PacifiCorp, PC/UP&L Merging Corp.	)))	Docket No. EC88-2-000

ANNOUNCEMENT OF REMAINING EXISTING CAPACITY

Take Notice that on January 6, 1989 Utah Power & Light Company, PacifiCorp, and PC/UP&L Merging Corp., in accordance with the Federal Energy Regulatory Commission's Opinion No. 318, dated October 26, 1988, filed their Announcement of Remaining Existing Capacity (Announcement) available to Qualifying Entities for firm transmission service as provided for in Opinion No. 318. On January 9, 1989 Utah Power & Light Company and PacifiCorp were merged with and into PC/UP&L Merging Corp. whose name was simultaneously changed to PacifiCorp (the Company).

Within 90 days of this Notice, those seeking status as Qualifying Entities must file with the Company, as provided for in the Announcement, all executed contracts which they have negotiated for firm capacity and energy which would utilize the Remaining Existing Capacity.

Any utility wishing a copy of the Announcement should contact:

Dennis P. Steinberg, Director
Power Planning
920 SW Sixth Avenue, Room 424
Portland, Oregon 97204

or

J. Lynn Rasband
Assistant Vice President
Planning & Engineering
1407 West North Temple
Salt Lake City, Utah 84140

roredord.doc

Exhibit A

Announcement of
Remaining Existing Capacity

EXHIBIT A

ANNOUNCEMENT OF REMAINING EXISTING CAPACITY (REC)

Introduction

In the Federal Energy Regulatory Commission (FERC) Opinion No. 318 (Opinion No. 318), PacifiCorp (Company) is required to include as part of its Compliance Filing a determination and identification of the portion of its total transmission capability that could be used for firm deliveries by wheeling customers from a Point of Receipt (POR) to a Point of Delivery (POD). This portion of the Compliance Filing identifies the transmission capability across pertinent constrained areas (identified by letter designation on Schedules 1 and 4) of the Company's transmission system, identifies the portion of such capability needed to reliably serve the Company's native loads and firm contracts entered into prior to the Merger Application, and identifies the difference between these quantities as the Remaining Existing Capacity (REC). The determination of transmission capabilities is complex and it is not always possible to identify a single value for a transmission constraint because of interactions between parallel transmission systems, changes in generation/load patterns and other operating considerations. The Company also recognizes that various wheeling requests must be accommodated simultaneously and that there may be conflicting interactions between requests for transmission service as indicated by the notes of Schedule 3. The Company believes that in such cases it may be necessary to review the REC allocations after all requests for transmission service have been received. The constrained areas where transmission interactions become a factor have been identified through footnotes or other forms of notation in Schedules 3 and 6.

Schedules in This Exhibit

Schedules 1 and 4 display the REC information and identify the constrained areas by letter designation on geographic maps. Schedules 2 and 5 display the resulting REC in tabular form. Schedules 3 and 6 show transmission capabilities used and the determination of REC through the constrained areas. The maps and supporting tables for each constrained area are organized into the "Eastern Division" area and the "Western Division" area. Schedule 7 contains workpapers supporting the determination of transmission capabilities for the Eastern and Western Divisions.

The Eastern Division area includes the Company's system in eastern Idaho, Wyoming and Utah. The Western Division contains the Company's systems in California, Oregon, Washington, Montana and northern Idaho. For each constrained area identified on the maps, supporting pages in Schedules 3 and 6 describe the basis for: 1) the determination of the transmission capability; and 2) the basis for the reservation of such capability required to reliably serve native load and pre-merger firm off-system contracts. The REC is determined by the difference between these quantities across each constrained area. The REC is provided on a year-by-year basis for the five-year transition period including the effect of native load requirements, contract changes and planned transmission additions (Schedule 7). The REC is allocated into Tiers 1, 2 and 3 with the constraining area(s) identified on the associated REC tabulations in Schedules 2 and 5.

It is generally assumed that sufficient transmission capability exists between substations within each of the areas shown on the maps. Therefore, when a REC is identified from one area to another area, that REC is assumed to be available from any particular substation in the first area to any particular substation in the second area. However, as Opinion No. 318 recognizes on p. 42, requests for wheeling within such an area could exceed the engineering limits of the system. This may require new transmission additions which will be provided pursuant to the terms of the Tariff in Exhibit B. Specific questions concerning a REC where a local engineering limit may exist will be responded to within 15 days.

Transmission Capability and REC

Transmission capabilities have been determined following normal utility operating and planning practices and criteria to avoid equipment damage and limit service interruptions for likely contingencies such as a line or transformer outage. The REC is then determined from these transmission capabilities. Following an outage on the system, transmission capability is reduced and, therefore, the REC and any associated schedules of power and energy may need to be reduced. In situations where the REC is available on a single line, any associated schedules of power and energy will be completely interrupted for an outage of that single line. When the REC is available on several lines, the transmission capability and, therefore, REC may only need to be reduced for a single line outage. For example, even though firm transmission service may be provided to the Four Corners area, the loss of the Pinto-Four Corners line would interrupt such service and the Company would have to interrupt all schedules on the line. In addition, other line outages on the Company's system or in other systems may limit the Company's ability to provide firm transmission service under outage conditions. Loss of the Ben Lomond-Borah line, for example, would require a reduction in the REC available in the northern Utah area (Path C), in order to reliably prepare for the outage of another line.

Transmission capability is also affected by operating conditions within the Western Systems Coordinating Council (WSCC) system. An outage of the Pacific Intertie, for example, reduces the transmission capability from Utah into the Arizona area. While it would not be reasonable to limit the amount of REC available in anticipation of these very severe outages, the purchaser of such services must be aware that under certain severe conditions, firm transmission service must be curtailed in order to maintain system reliability. This is required by prudent utility practice and governing reliability criteria such as the Minimum Operating Reliability Criteria for the WSCC. Under severe transmission outage conditions, or other conditions (such as loop flow) which reduce the available transmission capability, it is anticipated that firm transmission services will be curtailed.

The portion of the transmission capability that has been reserved to reliably serve firm and interruptible native load customers and pre-merger firm contract customers, has been identified through each constrained area on the Company's transmission network. While it is not a standard utility practice to identify the portion of the capability of specific transmission facilities necessary to provide for the needs of native load customers, etc., the Company has approached the requirement of Opinion No. 318 using a combination of studies, projected load growth over the next five years, operational judgement and a working knowledge of the system.

It should be noted, however, that the Company's transfer rights across the Idaho Power Company (IPC) system and the Company's entitlement rights involving the Pacific Intertie do not have a REC determination because the underlying contracts which establish the Company's transfer rights do not allow third-party use and provide that any unused capacity reverts to the IPC and the Bonneville Power Administration (BPA), respectively. This is also true in many of the Company's Western Division service areas which are integrated in large part by contracts with the BPA.

Application for Qualifying Entity Status

Within 90 days of this Announcement, utilities wishing to be designated as Qualifying Entities for allocation purposes, as provided for in Opinion No. 318, must file with the Company all executed contracts which they have negotiated for firm transactions which would utilize the REC established herein. Such filings must contain sufficient information to enable the Company to clearly ascertain the point(s) on the Company's transmission system between which transmission service is required, the maximum Contract Demand (MW) that must be accommodated, the date on which service is expected to commence and the duration of the service. Filings should be sent by registered mail to the following:

Robert M. Smith
Senior Vice President
Pacific Power & Light Company
920 SW Sixth Avenue
Portland, Oregon 97204

Exhibit A

Schedule 1

Eastern Division Geographic Map

REMAINING EXISTING CAPACITY DETERMINATION
EASTERN DIVISION
1989 – 1993

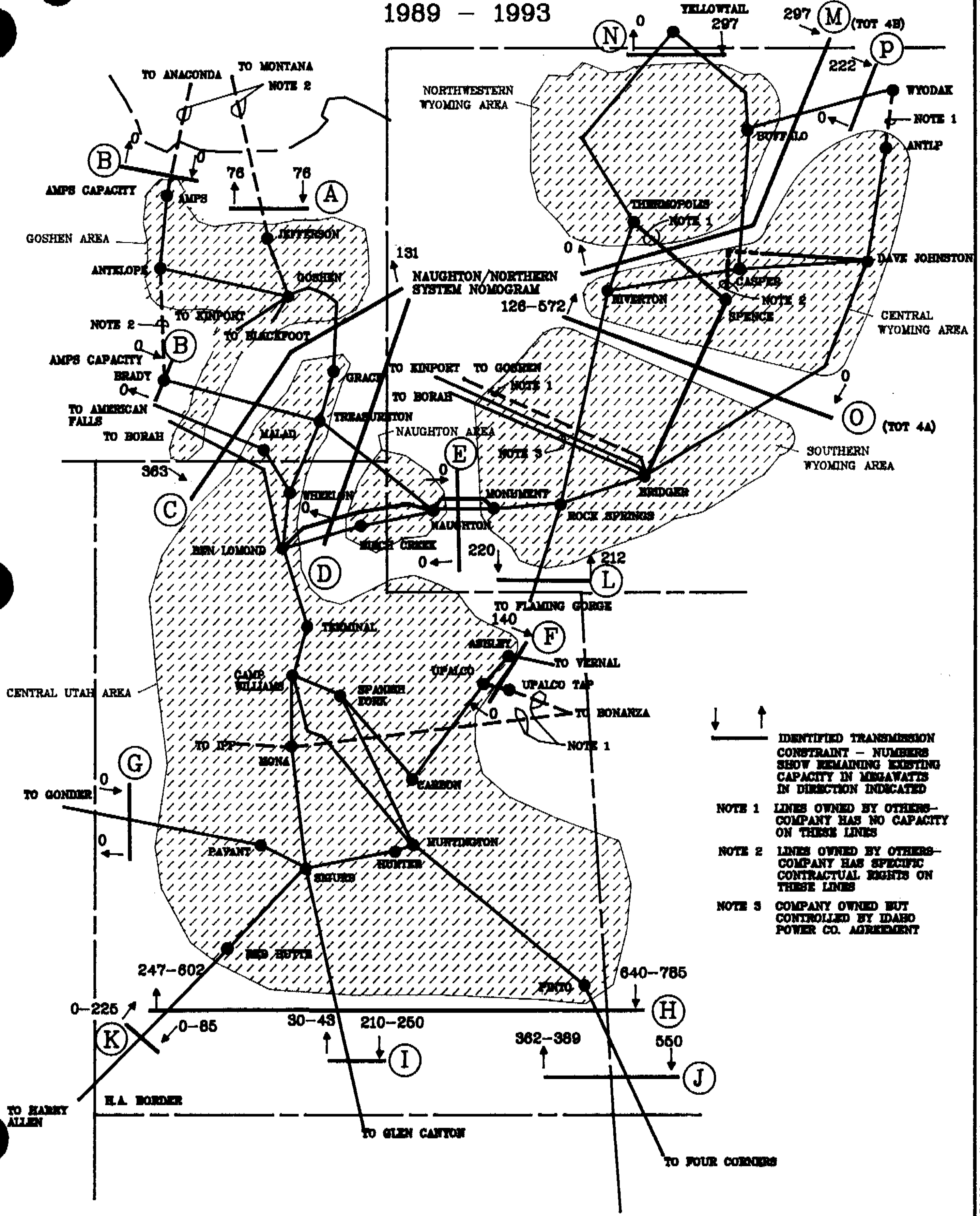


Exhibit A

Schedule 2

Eastern Division REC Tabulation

EASTERN DIVISION

REMAINING EXISTING CAPACITY (REC) 1989-1993

	TOTAL	PATH CONSTRAINT	TIER 1 20%	TIER 2 30%	TIER 3 50%
(2) FROM MONTANA AREA TO:					
(4) GOSHEN AREA	76	A	15	23	38
(5) NAUGHTON AREA	76	A	15	23	38
(6) CENTRAL UTAH AREA	76	A	15	23	38
(8) GLEN CANYON	76	A	15	23	38
(9) FOUR CORNERS	76	A	15	23	38
(10) HA BORDER	0-76	A	0-15	0-23	0-38
(11) VERNAL	76	A	15	23	38
(4) FROM GOSHEN AREA TO:					
(2) MONTANA AREA	76	A	15	23	38
(5) NAUGHTON	NOTE D				
(6) CENTRAL UTAH AREA	363	C	73	109	182
(8) GLEN CANYON	210-250	I	42-50	63-75	105-125
(9) FOUR CORNERS	363	C	73	109	182
(10) HA BORDER	0-85	K	0-17	0-26	0-43
(11) VERNAL AREA	140	F	28	42	70
(6) FROM CENTRAL UTAH TO:					
(2) MONTANA AREA	76	A	15	23	38
(4) GOSHEN AREA	131	C	26	39	66
(5) NAUGHTON	NOTE D				
(8) GLEN CANYON	210-250	I	42-50	63-75	105-125
(9) FOUR CORNERS	550	J	110	165	275
(10) HA BORDER	0-85	K	0-17	0-26	0-43
(11) VERNAL AREA	140	F	28	42	70
(8) FROM GLEN CANYON TO:					
(2) MONTANA AREA	30-43	I	6-9	9-13	15-22
(4) GOSHEN AREA	30-43	I	6-9	9-13	15-22
(5) NAUGHTON	30-43	I	6-9	9-13	15-22
(6) CENTRAL UTAH AREA	30-43	I	6-9	9-13	15-22
(9) FOUR CORNERS	30-43	I	6-9	9-13	15-22
(10) HA BORDER	0-43	I,K	0-9	0-13	0-22
(11) VERNAL AREA	30-43	I	6-9	9-13	15-22
(9) FROM FOUR CORNERS TO:					
(2) MONTANA AREA	76	A	15	23	38
(4) GOSHEN AREA	131	C	26	39	66
(5) NAUGHTON	247-389	H,J	49-78	74-117	124-195
(6) CENTRAL UTAH AREA	247-389	H,J	49-78	74-117	124-195
(8) GLEN CANYON	210-250	I	42-50	63-75	105-125
(10) HA BORDER	0-85	K	0-17	0-26	0-43
(11) VERNAL AREA	140	F	28	42	70
(10) FROM HA BORDER TO:					
(2) MONTANA AREA	0-76	A,K	0-15	0-23	0-38
(4) GOSHEN AREA	0-131	C,K	0-26	0-39	0-66
(5) NAUGHTON	0-225	K	0-45	0-68	0-113
(6) CENTRAL UTAH AREA	0-225	K	0-45	0-68	0-113
(8) GLEN CANYON	0-225	K	0-45	0-68	0-113
(9) FOUR CORNERS	0-225	K	0-45	0-68	0-113
(11) VERNAL AREA	0-140	F,K	0-28	0-42	0-70

EASTERN DIVISION

REMAINING EXISTING CAPACITY (REC) 1989-1993

	TOTAL	PATH CONSTRAINT	TIER 1 20%	TIER 2 30%	TIER 3 50%
(12) FROM NW WYOMING AREA TO:					
(13) CENTRAL WYOMING AREA	297	M	59	89	149
(17) WYODAK	222	P	44	67	111
(14) FROM SO WYOMING AREA TO:					
(13) CENTRAL WYOMING AREA	126-572	O	25-114	38-172	63-286
(16) FLAMING GORGE	220	L	44	66	110
(15) FROM YELLOWTAIL AREA TO:					
(12) NW WYOMING AREA	297	N	59	89	149
(13) CENTRAL WYOMING AREA	297	M,N	59	89	149
(17) WYODAK	222	P	44	67	111
(16) FROM FLAMING GORGE TO:					
(13) CENTRAL WYOMING AREA	126-212	L,O	25-42	38-64	63-106
(14) SO WYOMING AREA	212	L	42	64	106

Note D: See backup sheet for Path D West to East.

EASTERN DIVISION

REMAINING EXISTING CAPACITY (REC) 1989-1993

FROM AREA	TO AREA (1) ANACONDA	(2) MONTANA	(3) AMPS	(4) GOSHEN	(5) NAUGHTON	(6) CENT UT	(7) GONDER	(8) GLEN C	(9) 4 CORNERS	(10) HA BORDER	(11) VERNAL	(12) NW WYO	(13) CENT WYO	(14) SO WYO	(15) YELLOW	(16) FLAMING G	(17) WYODAK
(1) ANACONDA	-	0(B)	0(B)	0(B)	0(B)	0(B)	0(B,G)	0(B)	0(B)	0(B,K)	0(B)	0(B,E,M)	0(B,E)	0(B,E)	0(B,E,M,N)	0(B,E)	0(B,E,M)
(2) MONTANA AREA	0(B)	-	0(B)	76(A)	76(A)	76(A)	0(G)	76(A)	76(A)	0-76(A,K)	76(A)	0(E,M)	0(E)	0(E)	0(E,M,N)	0(E)	0(E,M)
(3) AMPS CAPACITY	0(B)	0(B)	-	0(B)	0(B)	0(B)	0(B,G)	0(B)	0(B)	0(B,K)	0(B)	0(B,E,M)	0(B,E)	0(B,E)	0(B,E,M,N)	0(B,E)	0(B,E,M)
(4) GOSHEN AREA	0(B)	76(A)	0(B)	-	Note(D)	363(C)	0(G)	210-250(I)	363(C)	0-85(K)	140(F)	0(E,M)	0(E)	0(E)	0(E,M,N)	0(E)	0(E,M)
(5) NAUGHTON AREA	0(B,D)	0(D)	0(B,D)	0(D)	-	0(D)	0(D,G)	0(D)	0(D)	0(D,K)	0(D)	0(E,M)	0(E)	0(E)	0(E,M,N)	0(E)	0(E,M)
(6) CENTRAL UTAH AREA	0(B)	76(A)	0(B)	131(C)	Note(D)	-	0(G)	210-250(I)	550(J)	0-85(K)	140(F)	0(E,M)	0(E)	0(E)	0(E,M,N)	0(E)	0(E,M)
(7) GONDER	0(B,G)	0(G)	0(B,G)	0(G)	0(G)	0(G)	-	0(G)	0(G)	0(G,K)	0(G)	0(E,G,M)	0(E,G)	0(E,G)	0(E,G,M,N)	0(E,G)	0(E,G,M)
(8) GLEN CANYON	0(B)	30-43(I)	0(B)	30-43(I)	30-43(I)	30-43(I)	0(G)	-	30-43(I)	0-43(I,K)	30-43(I)	0(E,M)	0(E)	0(E)	0(E,M,N)	0(E)	0(E,M)
(9) FOUR CORNERS	0(B)	76(A)	0(B)	131(C)	247-389(HJ)	247-389(HJ)	0(G)	210-250(I)	-	0-85(K)	140(F)	0(E,M)	0(E)	0(E)	0(E,M,N)	0(E)	0(E,M)
(10) HA BORDER	0(B,K)	0-76(A,K)	0(B,K)	0-131(C,K)	0-225(K)	0-225(K)	0(G,K)	0-225(K)	0-225(K)	-	0-140(F,K)	0(E,K,M)	0(E,K)	0(E,K)	0(E,K,M,N)	0(E,K)	0(E,K,M)
(11) VERNAL/UPALCO TAP	0(B,F)	0(F)	0(B,F)	0(F)	0(F)	0(F)	0(F,G)	0(F)	0(F)	0(F,K)	-	0(E,F,M)	0(E,F)	0(E,F)	0(E,F,M,N)	0(E,F)	0(E,F,M)
(12) NW. WYOMING	0(B,D,E,O)	0(D,E,O)	0(B,D,E,O)	0(D,E,O)	0(E,O)	0(D,E,O)	0(D,E,G,O)	0(D,E,O)	0(D,E,O)	0(D,E,K,O)	0(D,E,O)	-	297(M)	0(O)	0(N)	0(O)	222(P)
(13) CENTRAL WYOMING	0(B,D,E,O)	0(D,E,O)	0(B,D,E,O)	0(D,E,O)	0(E,O)	0(D,E,O)	0(D,E,G,O)	0(D,E,O)	0(D,E,O)	0(D,E,K,O)	0(D,E,O)	0(M)	-	0(O)	0(M,N)	0(O)	0(M)
(14) SO. WYOMING	0(B,D,E)	0(D,E)	0(B,D,E)	0(D,E)	0(E)	0(D,E)	0(D,E,G)	0(D,E)	0(D,E)	0(D,E,K)	0(D,E)	0(M)	126-572(O)	-	0(M,N)	220(L)	0(M)
(15) YELLOWTAIL	0(B,D,E,O)	0(D,E,O)	0(B,D,E,O)	0(D,E,O)	0(E,O)	0(D,E,O)	0(D,E,G,O)	0(D,E,O)	0(D,E,O)	0(D,E,K,O)	0(D,E,O)	297(N)	297(M,N)	0(O)	-	0(O)	222(P)
(16) FLAMING GORGE	0(B,D,E)	0(D,E)	0(B,D,E)	0(D,E)	0(E)	0(D,E)	0(D,E,G)	0(D,E)	0(D,E)	0(D,E,K)	0(D,E)	0(M)	126-212(L,D)	212(L)	0(M,N)	-	0(M)
(17) WYODAK	0(BDEMOP)	0(DEMOP)	0(BDEMOP)	0(DEMOP)	0(E,M,O,P)	0(DEMOP)	0(DEGMOP)	0(DEMOP)	0(DEMOP)	0(DEKMOP)	0(DEMOP)	0(M,P)	0(M,P)	0(M,O,P)	0(M,N,P)	0(M,O,P)	-

Example: The REC from Goshen, Line (4), to Four Corners, Column (9), is 363 MW and is limited by the identified transmission constraint Path C, as shown at the intersection of Line (4) and Column (9).

Note: Numbers shown are MW. Constraining paths enclosed in parenthesis (). See backup sheets for detail.
Note (D): See backup sheet for Path D West to East.

Exhibit A

Schedule 3

Eastern Division
Constrained Area
REC Determinations

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH A

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	85	85	85	85	85
2. Native Load Capacity Requirement:					
a. IPC 10% Allocation	9	9	9	9	9
	======	======	======	======	======
3. Available REC (1 - 2):	76	76	76	76	76
South to North					
1. Transmission Capacity:	85	85	85	85	85
2. Native Load Capacity Requirement:	0	0	0	0	0
a. IPC 10% Allocation	9	9	9	9	9
	======	======	======	======	======
3. Available REC (1 - 2):	76	76	76	76	76

Transmission Line in the Constraint: Jefferson-Anaconda (Millcreek) 161 kV line.

Transmission Capacity Basis: This transmission line is 85 MW of the 337 MW shown as Path 22 on Exhibit 13, Schedule 8. The remaining 252 MW is the capacity of the AMPS line, which is Identified Transmission Constraint Path B.

Native Load Capacity Basis: The 10% allocation for IPC is as per letter dated 02/01/51 to modify Service Agreement C1 of the IPC/MPC/UP&L Agreement for this line.

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH B

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	96	96	96	96	96
2. Native Load Capacity Requirement:					
a. Integration of PP&L-WY Area with Utah	96	96	96	96	96
	======	======	======	======	======
3. Available REC (1 - 2):	0	0	0	0	0
South to North					
1. Transmission Capacity:	96	96	96	96	96
2. Native Load Capacity Requirement:					
a. Integration of PP&L-WY Area with Utah	96	96	96	96	96
	======	======	======	======	======
3. Available REC (1 - 2):	0	0	0	0	0

Transmission Line in the Constraint: Antelope-AMPS-Millcreek 230 kV (AMPS) line.

Transmission Capacity Basis: The AMPS line capacity is 252 MW of the 337 MW (Path 22, Exhibit 13, Schedule 8). The Merged Company's ownership right in this line is 96 MW (78 MW UP&L, 18 MW PP&L). Other owners in this line are IPC and MPC.

Native Load Capacity Basis: The Merged Company will use this AMPS capacity to integrate the PP&L-WY area with the Utah area along with its Naughton-Monument capacity and the integration service contracted from IPC pursuant to the Fall 1988 Memorandum of Agreement between IPC, UP&L and PP&L.

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH C

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	800	800	800	800	800
2. Native Load Capacity Requirement:					
a. AMPS Capacity for Wyoming Integration	96	96	96	96	96
b. Idaho Capacity for Wyoming Integration	104	104	104	104	104
c. Capacity for Generation Reserve	237	237	237	237	237
Subtotal	437	437	437	437	437
3. Available REC (1 - 2):	363	363	363	363	363
South to North					
1. Transmission Capacity:	800	800	800	800	800
2. Native Load Capacity Requirement:					
a. AMPS Capacity for Wyoming Integration	96	96	96	96	96
b. Idaho Capacity for Wyoming Integration	104	104	104	104	104
c. Delivery of Sierra Pacific Sale (Note)	44	44	44	44	44
d. Goshen Area Load	325	325	325	325	325
e. Generation Reserve Commitment to NWPP	100	100	100	100	100
Subtotal	669	669	669	669	669
3. Available REC (1 - 2):	131	131	131	131	131

Transmission Lines in the Constraint:

Ben Lomond-Borah 345 kV line, Malad-American Falls 138 kV line, Treasureton-Brady 230 kV line, Grace Goshen 161 kV line.

Transmission Capacity Basis:

North-South: Path C is limited to 800 MW, with Path D at 930 MW, as shown on the Naughton/Northern Utah System Nomogram (Exhibit 13, Schedule 6).

South-North: Path C is limited to 800 MW by flows from Ben Lomond north and the Naughton-Treasureton flow which must serve the Northern Utah and Southern Idaho load north of Ben Lomond (see transmission capacity study results in Schedule 7).

Native Load Capacity Basis:

North-South: The simultaneous rating of Path C is 800 MW with the flow west of Naughton (Path D) at its maximum rating of 930 MW. Path D is fully utilized to deliver Naughton generation (710 MW) and the 400-530 MW of integration on Path C. The AMPS capacity and Idaho capacity for Wyoming-Utah integration is part of a Fall 1988 Memorandum of Agreement with IPC to provide integration services. The transmission capacity for generation reserve will accommodate the loss of one of our five large units (400-415 MW) in the Utah area. While Northwest Power Pool (NWPP) resources can be demanded only from the north across this Path, the reserved transmission capacity has been prorated between this Path and the Four Corners Path (Path J) according to transmission capacity (415 MW * 800/1400 MW = 237 MW for Path C; and 415 MW * 600/1400 MW = 178 MW for Path J). This is to accommodate the anticipated requests for transmission service from the Northwest to the Four Corners area. By dividing this capacity, more REC is available from North to South on this Path, which has been suggested to be in high demand. Additionally, reserving capacity on the Four Corners line from South to North will not interfere with the high demand REC from the Northwest to the Southwest. Nevertheless, it does provide flexibility in maintaining reliable service by replacing generation outages in Utah with purchases from the Desert Southwest. Dividing the reserve between this Path and the Four Corners Path is perceived to be preferred by the other utilities as compared to reserving the entire 415 MW of capacity on Path C.

South-North: The AMPS capacity and Idaho capacity for Wyoming-Utah integration is part of a Fall 1988 Memorandum of Agreement with IPC to provide integration services. Delivery of 44 MW to Sierra Pacific Power Company - under the terms of the 09/12/77 amendment to the Interconnection Agreement between UP&L and SPP, SPP has the option to take delivery of up to 50% of its 87 MW purchase from UP&L through the IPC system. The Merged Company has an obligaion to provide generation reserves to NWPP in an amount equal to 7% of thermal generation plus 5% of hydro generation. This reserve requirement is typically in the neighborhood of 500 MW during high-load hours. It is estimated that at least 100 MW of this capacity should be reserved on the Utah System. The Merged Company must stand prepared to provide its generation reserve to NWPP.

Note: The Merged Company has an obligation to deliver 87 MW over this path under certain conditions.

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH D

Identified Transmission Constraint	1989	1990	1991	1992	1993
East to West					
1. Transmission Capacity:	930	930	930	930	930
2. Native Load Capacity Requirement:					
a. Deliver Naughton Generation	710	710	710	710	710
b. Less Naughton Area Minimum Load	(150)	(150)	(150)	(150)	(150)
c. System Integration	400	400	400	530	530
Subtotal	960	960	960	1,090	1,090
3. Available REC (1 - 2):	0	0	0	0	0

Transmission Lines in the Constraint: Naughton-Treasureton 230 kV line, Naughton-Ben Lomond 230 kV line, Birch Creek-Ben Lomond 230 kV line.

Transmission Capacity Basis: Transmission Path D is limited to the 930 MW shown as the "West of Naughton" limit on the Naughton/Northern Utah System Nomogram (Exhibit 13, Schedule 6).

Native Load Capacity Basis: East-West: The maximum capability west of Naughton is required to transport the Merged Company's resources at Naughton. The resources at Naughton are 710 MW of Naughton generation, 400-530 MW of integration (see Path E) from PP&L-Wyoming less minimum load in the Naughton area (150 MW).

West to East: No capacity or REC is identified for flows west to east on Path D as there is no REC available east of Naughton (Path E) and the capacity from west to east on Path D is greater than the Naughton area load. Therefore, there is no practical constraint on Path D from west to east.

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH E

Identified Transmission Constraint	1989	1990	1991	1992	1993
East to West					
1. Transmission Capacity:	400	400	400	530	530
2. Native Load Capacity Requirement:					
a. System Integration	400	400	400	530	530
	======	======	======	======	======
3. Available REC (1 - 2):	0	0	0	0	0
West to East					
1. Transmission Capacity:	420	420	420	600	600
2. Native Load Capacity Requirement:					
a. System Integration	420	420	420	600	600
	======	======	======	======	======
3. Available REC (1 - 2):	0	0	0	0	0

Transmission Lines in the Constraint: Naughton-Monument 230 kV line (1989-1991), Naughton-Monument 230 kV lines 1 and 2 (1992-1993).

Transmission Capacity Basis: The maximum transfer capability from Monument to Naughton is 400 MW (1989-91) and 530 MW (1992-1993) (Exhibit 8, pp. 31-33). The transfer capability from Naughton to Monument is 420 MW (1989-1991) and 600 MW (1992-1993). (See FERC Trial Staff Data Request No. 1, Request SE1-7C.)

Native Load Capacity Basis: The entire capacity of the Naughton interconnection between PP&L-Wyoming and UP&L is needed to capture the merger benefits (Exhibit 8, pp. 34-35). In addition to the Naughton path, the Merged Company has a Memorandum of Understanding to provide additional integration services through IPC (see Path C).

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH F

Identified Transmission Constraint	1989	1990	1991	1992	1993
East to West					
1. Transmission Capacity:	140	140	140	140	140
2. Native Load Capacity Requirement:					
a. WAPA Wheeling Contract	140	140	140	140	140
	======	======	======	======	======
3. Available REC (1 - 2):	0	0	0	0	0
West to East					
1. Transmission Capacity:	140	140	140	140	140
2. Native Load Capacity Requirement:	0	0	0	0	0
	======	======	======	======	======
3. Available REC (1 - 2):	140	140	140	140	140

Transmission Line in the Constraint: Carbon-UPALCO-Ashley-Vernal 138 kV line.

Transmission Capacity Basis: 70 MW is shown for Vernal-Ashley and 70 MW for UPALCO-UPALCO Tap (Exhibit 13, Schedule 9, p. 5, lines 41 & 42). Mr. Tucker also testified that the limit was 140 MW from Carbon to UPALCO (TR 3319).

Native Load Capacity Basis: East-West: UP&L has a long-term firm wheeling obligation to WAPA for its Utah customers under contracts 2436 and 2470. The first 140 MW of this contract obligation is scheduled from Vernal with the remaining scheduled from Glen Canyon on the Sigurd line.

West-East: The Hunter Wheeling Agreement, dated 10/24/80, provides that UP&L will wheel to Moon Lake any amount requested up to the DG&T ownership in Hunter No. 2 (155 MW). In the past, service has been as high as 94 MW before the Bonanza-Mona line was completed. Any new requests for wheeling on this Path must be coordinated with the obligations of the Hunter Wheeling Agreement.

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH G

Identified Transmission Constraint	1989	1990	1991	1992	1993
East to West					
1. Transmission Capacity:	180	180	180	180	180
2. Native Load Capacity Requirement:					
a. Contract with Sierra Pacific	180	180	180	180	180
	======	======	======	======	======
3. Available REC (1 - 2):	0	0	0	0	0
West to East					
1. Transmission Capacity:	150	150	150	150	150
2. Native Load Capacity Requirement:					
a. Contract with Sierra Pacific	150	150	150	150	150
	======	======	======	======	======
3. Available REC (1 - 2):	0	0	0	0	0

Transmission Line in the Constraint: Pavant-Gonder 230 kV line.

Transmission Capacity Basis: Exhibit 13, Schedule 8, p. 1, Path 24.

Native Load Capacity Basis: The capacity rights in this line are assigned to Sierra Pacific. The UP&L-SPP Interconnection Agreement (05/19/71), paragraph 5.2 states:

"5.2 In consideration of the charges to be paid by Sierra Company as set forth in Article VI hereof, Utah Company agrees that Sierra Company shall have exclusive use of the capacity in the 230 kV facilities between Sigurd Substation and the Point of Interconnection in excess of the capacity required by Utah Company to fulfill its transmission obligations and sale of power and energy requirements within its service area pursuant to Paragraph 5.1."

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH H

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	755	755	1,000	1,000	1,000
2. Native Load Capacity Requirement:					
a. NPC Sales Agreement	0	0	140	140	140
b. Salt River Capacity Exchange	90	90	90	60	50
c. DG&T Capacity to Nevada	25	25	25	25	25
Subtotal	115	115	255	225	215
3. Available REC (1 - 2) (See Transmission Capacity Basis Below):	640	640	745	775	785
South to North					
1. Transmission Capacity:	755	755	1,070	1,070	1,070
2. Native Load Capacity Requirement:					
a. Salt River Capacity Exchange	90	90	90	60	50
b. WAPA Wheeling Contract	240	240	240	240	240
c. Capacity for Generation Reserve	178	178	178	178	178
Subtotal	508	508	508	478	468
3. Available REC (1 - 2):	247	247	562	592	602

Transmission Lines in the Constraint: Pinto-Four Corners 345 kV line, Sigurd-Glen Canyon 230 kV line, Red Butte-Border 345 kV line.

Transmission Capacity Basis: The transmission capacities for years 1991-1993 are based on the Utah South Boundary Nomograms (Schedule 7). Because of these nomograms, the transmission capacity of Path H could be reduced by as much as 161 MW north to south if Path K is fully utilized.

Native Load Capacity Basis: The UP&L-NPC Power Sales Agreement provides for delivering 140 MW from north to south only. Also see non-simultaneous discussions for Paths I, J and K. For explanation of Generation reserve, see Path C.

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH I

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	300	300	300	300	300
2. Native Load Capacity Requirement:					
a. Salt River Return	90	90	90	60	50
3. Available REC (1 - 2) (Note 1):	210	210	210	240	·250
South to North					
1. Transmission Capacity:	300	300	300	300	300
2. Native Load Capacity Requirement:					
a. WAPA Wheeling Contract (Note 2)	240	240	240	240	240
b. Salt River Capacity Exchange	30	30	30	20	17
Subtotal	270	270	270	260	257
3. Available REC (1 - 2):	30	30	30	40	43

Transmission Line in the Constraint: Sigurd-Glen Canyon 345 kV line.

Transmission Capacity Basis: Exhibit 138, Schedule 9, p. 5, line 39 and TR 3318.

Native Load Capacity Basis: North-South: The return to Salt River is one of energy returns and would be returned during light-load hours. Transmission capacity to make this return has been estimated to be equal to the capacity required to bring the energy in, since the capacity is available for 12 hours a day and will be returned during the light-load hours. This capacity exchange is for the use of our native load.

South-North: UP&L has a long-term wheeling obligation to WAPA for its Utah customers under contracts 2436 and 2470. The first 140 MW of the contract obligation is scheduled at the Vernal interconnection; the balance is scheduled from Glen Canyon. The Salt River capacity/energy exchange is for our native load and would be delivered to Utah at Glen Canyon and Four Corners. For the purpose of this filing, one-third is assumed to be delivered at Glen Canyon and two-thirds at Four Corners.

Note 1: Because of simultaneous constraints on Path H, the transmission capacity and, therefore, the REC on Path J could be reduced by as much as 92 MW north to south and 30 MW south to north when Paths J and K are fully utilized. See the Utah South Boundary Nomogram (Schedule 7).

Note 2: The Merged Company has an obligation to deliver 300 MW over this path under certain conditions.

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH J

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	550	550	550	550	550
2. Native Load Capacity Requirement:	0	0	0	0	0
	======	======	======	======	======
3. Available REC (1 - 2):	550	550	550	550	550
South to North					
1. Transmission Capacity:	600	600	600	600	600
2. Native Load Capacity Requirement:					
a. Salt River Capacity Exchange	60	60	60	40	33
b. Capacity for Generation Reserve	178	178	178	178	178
Subtotal	238	238	238	218	211
	======	======	======	======	======
3. Available REC (1 - 2):	362	362	362	382	389

Transmission Line in the Constraint: Pinto-Four Corners 345 kV line.

Transmission Capacity Basis: Exhibit 13, Schedule 8 shows the capacity of this line at 600 MW. Nevertheless, recent studies required to determine the simultaneous capacity of the Sigurd-Glen Canyon line and the Pinto-Four Corners line with the current load at Pinto and the additional impedance of the Pinto phase shifters resulted in a rating of 600 MW into Pinto, which provides a capacity of only 550 MW to Four Corners. The illustrative technical study is provided in Schedule 7. The south to north capacity is not reduced by the Pinto load from the stated 600 MW capacity.

Native Load Capacity Basis: The Merged Company has no firm contracts on this line from north to south. The Salt River capacity exchange is discussed on Path I. Two-thirds of that capacity exchange is assumed to be delivered at Four Corners with one-third at Glen Canyon. For explanation of Generation Reserve, see Path C.

Note 1: Because of simultaneous constraints on Path H, the transmission capacity and, therefore, the REC on Path J could be reduced by as much as 169 MW north to south and 50 MW south to north when Paths I and K are fully utilized. See the Utah South Boundary Nomograms provided in Schedule 7.

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH K

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	0	0	150	250	250
2. Native Load Capacity Requirement:					
a. UP&L-NPC Sales Agreement	0	0	140	140	140
b. DG&T Contract Right	0	0	25	25	25
Subtotal	0	0	165	165	165
	======	======	======	======	======
3. Available REC (1 - 2) (Note 1):	0	0	0	85	85
South to North					
1. Transmission Capacity:	0	0	250	250	250
2. Native Load Capacity Requirement:					
a. NPC System Limitation	0	0	0	0	0
b. DG&T Contract Right	0	0	25	25	25
Subtotal	0	0	25	25	25
	======	======	======	======	======
3. Available REC (1 - 2):	0	0	225	225	225

Transmission Line in the Constraint: Red Butte-Border 345 kV line.

Transmission Capacity Basis: Exhibit 12, pp. 28-29 identify that the Nevada interchange capability is 250 MW. However, NPC is scheduling completion of the Westside-Decatur 230 kV line for June 1991. This line is required to achieve the 250 MW capacity. Before the Decatur line is in service, the capacity is 150 MW.

Native Load Capacity Basis: North-South: The Power Sales Agreement between UP&L and NPC (08/17/87) provides for 140 MW to be delivered in the north-south direction beginning in June 1990. DG&T has preliminary agreement for a 25 MW contract right in the transmission line.

South-North: Due to the limited transmission capacity into the Las Vegas area, particularly when that transmission capacity is needed to supply the Las Vegas load, it is likely that no firm capacity will be available from south to north because of limitations in the Las Vegas area.

Note 1: Because of simultaneous constraints on Path H, the transmission capacity and, therefore, the REC on Path K could be reduced by as much as 50 MW north to south when Paths I and J are fully utilized. See the Utah South Boundary Nomograms provided in Schedule 7.

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH L

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	220	220	220	220	220
2. Native Load Capacity Requirement:	0	0	0	0	0
	======	======	======	======	======
3. Available REC (1 - 2):	220	220	220	220	220
South to North					
1. Transmission Capacity:	220	220	220	220	220
2. Native Load Capacity Requirement:	8	8	8	8	8
	======	======	======	======	======
3. Available REC (1 - 2):	212	212	212	212	212

Transmission Line in the Constraint: Flaming Gorge 230/138 kV transformers.

Transmission Capacity Basis: The transmission constraint is the thermal limit on the Flaming Gorge transformers, and shown as Path 20 on Exhibit 13, Schedule 8.

Native Load Capacity Basis: PP&L has native load served off this line between Rock Springs and Flaming Gorge at Little Mountain and Firehole.

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH M (4B)

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	297	297	297	297	297
2. Native Load Capacity Requirement:	0	0	0	0	0
3. Available REC (1 - 2):	297	297	297	297	297
South to North					
1. Transmission Capacity:	297	297	314	318	319
2. Native Load Capacity Requirement:					
a. Load	127	127	144	148	149
b. WAPA Contract Obligation	170	170	170	170	170
Subtotal	297	297	314	318	319
3. Available REC (1 - 2):	0	0	0	0	0

Transmission Lines in the Constraint: North-South: Yellowtail-Buffalo 230 kV line, Yellowtail-Thermopolis 230 kV line.

South-North: Wyodak-Buffalo 230 kV line, Casper-Midwest 230 kV line, Riverton-Thermopolis 230 kV line.

Transmission Capacity Basis: North-South: This transmission constraint is the thermal limit on the Yellowtail-Buffalo 230 kV line for outage of the Yellowtail-Thermopolis 230 kV line.

South-North: This transmission capacity is limited by the simultaneous flows on Path O (4A) and as shown in the Merged Company Attachment Response IP/MP 2-18.a., p. 1 of 2. The increase Path M and Path O transfer capabilities in future years are shown in Schedule 7.

Native Load Capacity Basis: The 170 MW WAPA contract obligation is shown on p. 76, Section 5.2 of Mr. Tucker's rebuttal testimony workpapers.

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH N

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	297	297	297	297	297
2. Native Load Capacity Requirement:	0	0	0	0	0
	======	======	======	======	======
3. Available REC (1 - 2):	297	297	297	297	297
South to North					
1. Transmission Capacity:	297	297	314	318	319
2. Native Load Capacity Requirement:					
a. Load	127	127	144	148	149
b. WAPA Contract Obligation	170	170	170	170	170
Subtotal	297	297	314	318	319
	======	======	======	======	======
3. Available REC (1 - 2):	0	0	0	0	0

Transmission Line in the Constraint: North-South: Yellowtail-Buffalo 230 kV line, Yellowtail-Thermopolis 230 kV line.

South-North: Wyodak-Buffalo 230 kV line, Casper-Midwest 230 kV line, Riverton-Thermopolis 230 kV line.

Transmission Capacity Basis: North-South: This transmission constraint is the thermal limit on the Yellowtail-Buffalo 230 kV line for outage of the Yellowtail-Thermopolis 230 kV line.

South-North: This transmission capacity is limited by the simultaneous flows on Path O (4A) and as shown in the Merged Company Attachment Response IP/MP 2-18.a., p. 1 of 2. The increase Path M and Path O transfer capabilities in future years are shown in Schedule 7.

Native Load Capacity Basis: The 170 MW WAPA contract obligation is shown on p. 76, Section 5.2 of Mr. Tucker's rebuttal testimony workpapers.

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH O (4A)

Identified Transmission Constraint	1989	1990	1991	1992	1993
East to West					
1. Transmission Capacity:	580	580	780	780	780
2. Native Load Capacity Requirement:					
a. Southwest WY Load (Minimum)	267	273	309	319	321
b. WAPA Wheeling	8	8	8	8	8
c. Generation Integration	436	447	375	354	352
d. Generation Reserve for NWPP	100	100	100	100	100
Subtotal	811	828	792	781	781
3. Available REC (1 - 2):	0	0	0	0	0
West to East					
1. Transmission Capacity:	446	446	892	892	892
2. Native Load Capacity Requirement:					
a. Generation Integration	320	320	320	320	320
3. Available REC (1 - 2):	126	126	572	572	572

Transmission Lines in the Constraint: East-West: Dave Johnston-Difficulty 230 kV line, Riverton-Wyopo 230 kV line, Spence-Jim Bridger 230 kV (1991) lines.

West-East: Jim Bridger-Spence 230 kV line, Jim Bridger-Dave Johnston 230 kV line, Rock Springs-Riverton 230 kV line.

Transmission Capacity Basis: East-West: This transmission capacity is limited by the simultaneous flows on Path O (4A) and as shown in the Merged Company's response to Request No. IP/MP 2-18.a., p. 1 of 2. See also Exhibit 9, Schedule 4, p. 2 of 5. The increase Path M and Path O transfer capabilities in future years are shown in Schedule 7.

West-East: This transmission constraint is the thermal limit on two of the above lines for loss of the third.

Native Load Capacity Basis: East-West: The load is the minimum southwestern Wyoming area load. The reservation for generation integration is the Wyodak and Dave Johnston generation capacity 998 MW less the minimum Wyoming load. The remaining generation must be capable of being delivered across Path O. 100 MW of generation east of Path P provides a portion of the Company's operating reserves as required by the NWPP.

West-East: The west-to-east generation integration covers the loss of Dave Johnston 4 (320 MW).

REMAINING EXISTING CAPACITY (REC) CALCULATION

PATH P

Identified Transmission Constraint	1989	1990	1991	1992	1993
East to West					
1. Transmission Capacity:	273	273	273	273	273
2. Native Load Capacity Requirement:					
a. Wyodak Generation	248	248	248	248	248
b. Peaking Generation & Operating Reserves	100	100	100	100	100
Subtotal	348	348	348	348	348
3. Available REC (1 - 2):	0	0	0	0	0
West to East					
1. Transmission Capacity:	297	297	297	297	297
2. Native Load Capacity Requirement:					
a. BHP&L Sale	75	75	75	75	75
3. Available REC (1 - 2):	222	222	222	222	222

Transmission Line in the Constraint: Wyodak-Buffalo 230 kV line.

Transmission Capacity Basis:

East-West: The constraint is the thermal rating of the Wyodak-Buffalo 230 kV line. Since, for east-to-west schedules, the line functions as a portion of Path M (4B), the capacity is constrained depending on the requirements of Paths M (4B) and O (4A). The REC of Paths M and O are zero, thus the REC of Path P is zero.

West-East: The constraint is the thermal rating of the Wyodak-Buffalo 230 kV line.

Native Load Capacity Basis:

East-West: Wyodak generation is 248 MW. The Company has rights to 100 MW of BPH&L peaking generation located east of Wyodak. This generation is used to meet a portion of the Company's operating reserves for the NWPP.

West-East: During periods of Wyodak outage, the 75 MW firm sale to BHP&L will be delivered over this line. The sale to BHP&L is 75 MW, as shown on p. 2 of 3, Exhibit 9, Schedule 16.

Exhibit A

Schedule 4

Western Division Geographic Map

S[illegible]ULE 4

REMAINING EXISTING C[illegible]CITY DETERMINATION
WESTERN DIVISION
1989-1993

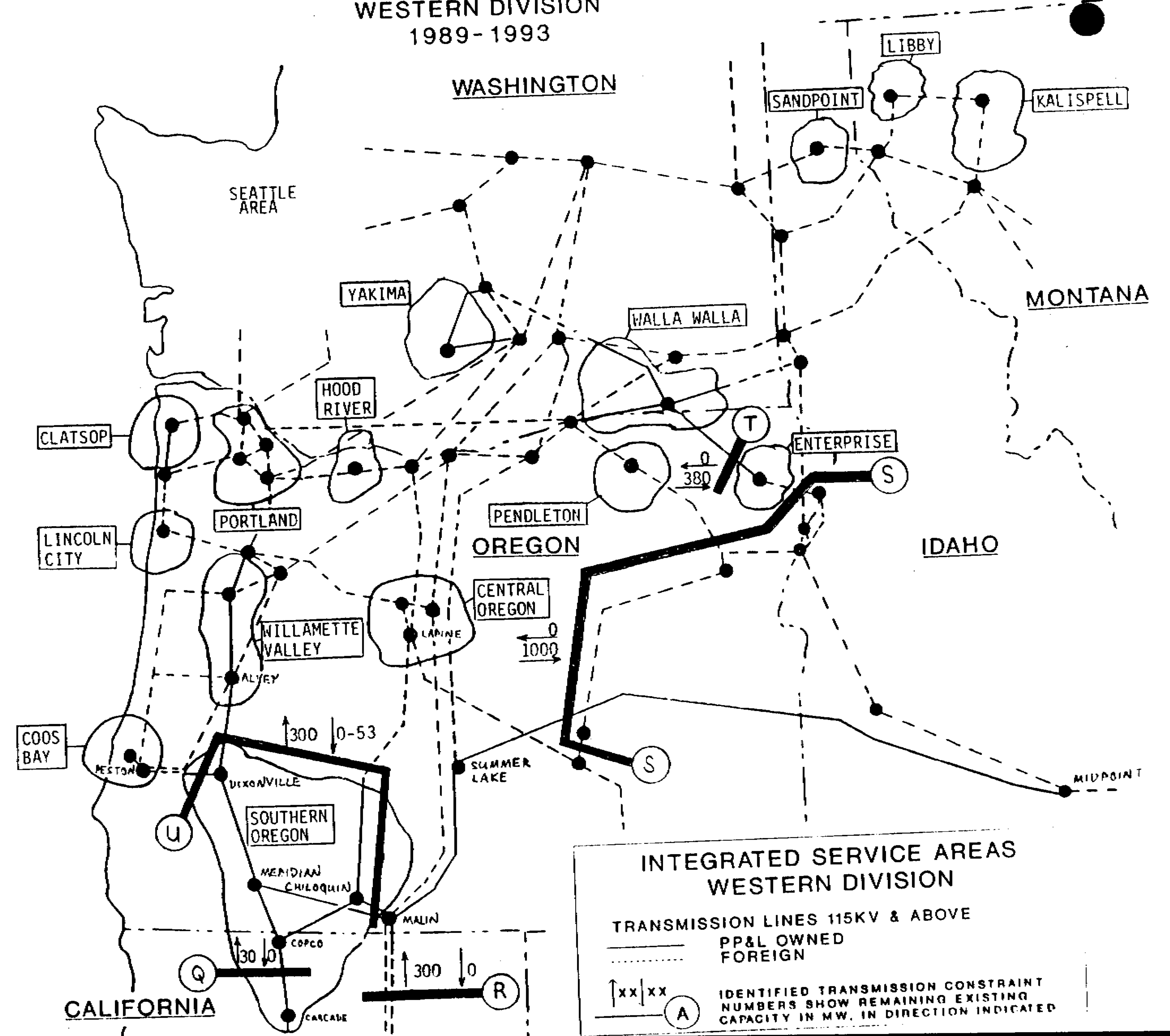


Exhibit A

Schedule 5

Western Division REC Tabulation

WESTERN DIVISION

REMAINING EXISTING CAPACITY (REC) 1989-1993

	TOTAL	PATH CONSTRAINT	TIER 1 20%	TIER 2 30%	TIER 3 50%
CASCADE TO:					
MIDPOINT	30	Q,U,S	6	9	15
WILLAMETTE VALLEY	30	Q,U	6	9	15
SOUTHERN OREGON	30	Q	6	9	15
WALLA WALLA TO:					
ENTERPRISE	380	T	76	114	190
WILLAMETTE VALLEY TO:					
MIDPOINT	0-53	U,S	0-11	0-16	0-26
SOUTHERN OREGON	0-53	U	0-11	0-16	0-26
SOUTHERN OREGON TO:					
MIDPOINT	300	U	60	90	150
WILLAMETTE VALLEY	300	U	60	90	150
CALIFORNIA AREA TO:					
MIDPOINT	300	R,S	60	90	150
WILLAMETTE VALLEY	0-53	R,U	0-11	0-16	0-26
SOUTHERN OREGON	0-53	R,U	0-11	0-16	0-26

WESTERN DIVISION

REMAINING EXISTING CAPACITY (REC) 1989-1993

POINT OF RECEIPT AREA	ENTERPRISE	MIDPOINT	POINT OF DELIVERY AREA				
			CASCADE	WALLA WALLA	WILLAMETTE VALLEY	SOUTHERN OREGON	CALIF.
ENTERPRISE	-	NA	NA	0(T)	NA	NA	NA
MIDPOINT	NA	-	0(S,U,Q)	NA	0(S,U)	0(S,U)	0(S,R)
CASCADE	NA	30(Q,U,S)	-	NA	30(Q,U)	30(Q)	0(Q,U,R)
WALLA WALLA	380(T)	NA	NA	-	NA	NA	NA
WILLAMETTE VALLEY	NA	0-53(U,S)	0(U,Q,)	NA	-	0-53(U)	0(U,R)
SOUTHERN OREGON	NA	300(U,S)	0(Q)	NA	300(U)	-	0(U,R)
CALIFORNIA	NA	300(R,S)	0(R,U,Q)	NA	0-53(R,U)	0-53(R,U)	-

NOTE: Numbers shown are MW. Constraining paths are enclosed in parenthesis ( ). See backup sheets for detail.

NA: Path not applicable-requires Third Party Agreement.

Exhibit A

Schedule 6

Western Division Constrained Area REC Determinations

REMAINING EXISTING CAPACITY
WESTERN DIVISION

PATH Q

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	100	100	100	100	100
2. Contract Requirement:					
a. Pacific Gas & Electric Contract	100	100	100	100	100
3. Available REC (1 - 2):	0	0	0	0	0
South to North					
1. Transmission Capacity:	30	30	30	30	30
2. Native Load Capacity Requirement:	0	0	0	0	0
3. Available REC (1 - 2):	30	30	30	30	30

Transmission Line in the Constraint: Cascade-COPCO 115 KV line.

Transmission Capacity Basis: This transmission line transfer capability iS 100 MW for Winter conditions North to South and 30 MW South to North as shown as Path 5A on Exhibit 13, schedule 8.

Native Load Capacity Basis: The sale to PG&E is 100 MW as shown on page 2 of 3, Exhibit 9, schedule 16 of Rodney M. Boucher prefiled testimony.

REMAINING EXISTING CAPACITY
WESTERN DIVISION

PATH R

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	300	300	300	300	300
2. Contract Requirements (Note 1):					
a. Southern Calf. Edison Contract	300	200	200	200	200
b. Sacramento Municipal	0	100	100	100	100
Total	300	300	300	300	300
3. Available REC (1 - 2):	0	0	0	0	0
South to North					
1. Transmission Capacity:	300	300	300	300	300
2. Available REC (Note 2):	300	300	300	300	300

Transmission Line in the Constraint: Pacific 500 KV A.C. Intertie.

Transmission Capacity Basis: PP&L scheduling rights are shown on page 2 of 11, Exhibit 13, schedule 9 of James D. Tucker prefiled testimony.

Note 1: The firm sales requirements are shown on page 2 of 3, Exhibit 9, schedule 16 of Rodney M. Boucher perfiled testimony.

Note 2: Pacific's rights are at least 300 MW and are not limited in any underlying contract.

REMAINING EXISTING CAPACITY
WESTERN DIVISION

PATH S

Identified Transmission Constraint	1989	1990	1991	1992	1993
East to West					
1. Transmission Capacity:	1530	1530	1530	1530	1530
2. Native Load Capacity Requirement:	1530	1530	1530	1530	1530
3. Available REC (1 - 2):	0	0	0	0	0
West to East					
1. Transmission Capacity:	1200	1200	1200	1200	1200
2. Native Load Capacity Requirement:					
a. Load	0	0	0	0	0
b. BPA Contract Rights (Note 1)	200	200	200	200	200
3. Available REC (1 - 2):	1000	1000	1000	1000	1000

Transmission Lines in the Constraint: Midpoint-Summer Lake 500 KV, Enterprise-Walla Walla 230 KV lines.

Transmission Capacity Basis: East to West: This transmission capacity is shown as Path 4 on Exhibit 13, schedule 8 of 2100 MW. 1530 MW is currently available to PP&L per the "Agreement for Transmission Services" between IPC and PP&L. Pages of the agreement are shown in schedule 7.
West to East: This transmission capacity is shown as Path 4 on Exhibit 13, schedule 8 of 1200 MW.

Native Load Capacity Basis: This Path integrates Jim Bridger and Eastern Division generation (integrated system) into the Pacific NW load areas.

Note 1: Contract rights of BPA are according to the Transmission Service Agreement of BPA and PP&L. Pages of the agreement are shown in schedule 7.

REMAINING EXISTING CAPACITY
WESTERN DIVISION

PATH 1

Identified Transmission Constraint	1989	1990	1991	1992	1993
East to West					
1. Transmission Capacity:	400	400	400	400	400
2. Native Load Capacity Requirement:	400	400	400	400	400
3. Available REC (1 - 2):	0	0	0	0	0
West to East					
1. Transmission Capacity:	400	400	400	400	400
2. Native Load Capacity Requirement:	20	20	20	20	20
3. Available REC (1 - 2):	380	380	380	380	380

Transmission Line in the Constraint: Walla Walla-Enterprise 230 KV line.

Transmission Capacity Basis: Constraining facility on line is rated 400 MW (series capacitor). This line is a portion of the transmission capacity as shown in Path 4 in Exhibit 13, schedule 8 and simultaneous capacity could be reduced based on schedules of other Path 4 facilities.

Native Load Capacity Basis: East to West: Native load requirements of the merged company west of Enterprise.
West to East: Native load at the merged company substation at Enterprise.

REMAINING EXISTING CAPACITY
WESTERN DIVISION

PATH U

Identified Transmission Constraint	1989	1990	1991	1992	1993
North to South					
1. Transmission Capacity:	915	915	915	915	915
2. Native Load Capacity Requirement:					
a. Southern Oregon/N. Calf. Load	1112	1140	1155	1170	1185
b. Generation	-350	-350	-350	-350	-350
c. Pacific Gas & Electric Sale	100	100	100	100	100
Total	862	890	905	920	935
3. Available REC (1 - 2):	53	25	10	0	0
South to North					
1. Transmission Capacity:	300	300	300	300	300
2. Native Load Capacity Requirement:	0	0	0	0	0
3. Available REC (1 - 2):	300	300	300	300	300

Transmission Lines in the Constraint: Alvey-Dixonville 230 KV lines, Dixonville-Reston 230 KV, La Pine-Chiloquin 230 KV, Malin-Meridian 500 KV, and Malin 500-230 KV transformer.

Transmission Capacity Basis: North to South: For loss of the Malin-Meridian 500 KV line the remaining lines are capable of serving a maximum of 915 MW of load.
South to North: For loss of the Malin-Meridian 500 KV line, the Malin 500/230 KV 300 MW transformer is the limiting facility.

Native Load Capacity Basis: The capability of the system is based on the transmission capability plus the local generation within the Southern Oregon/ Northern California load area. The average historical generation level of the predominant generation facilities being hydro has been 350 MW. The transmission system becomes inadequate to reliable serve the forecasted load by 1992. Mr. Rodney M. Boucher prefiled testimony Exhibit 8, pages 9 and 10 address the addition of the Eugene-Medford 500 KV line which will enhance the transmission capacity to serve native load.

Exhibit A

Schedule 7

Workpapers

WORKPAPERS

TABLE OF CONTENTS

E77805.05E

MERGED COMPANY TRANSMISSION
ADDITIONS 1989-1993

MERGED COMPANY TRANSMISSION ADDITIONS 1989-1993

ADDITION	NOTE	PROPOSED IN-SERVICE DATE
1. 230 kV Line-Bridger Pump to Firehole	As shown on Page 18 of Attachment Response SE 1-7C of FERC Trial Staff Data Request	June, 1989
2. 230 kV Line-South Trona to Monument	Same As #1	June, 1989
3. 230 kV Line-Spence to Bridger	As Shown on WSCC 10-Year Map, Schedule 7, Exhibit 13 - James D. Tucker Prefiled Testimony	November, 1990
4. 345 kV Line-Sigurd to Red Butte-To Nevada Border	Same As #3	November, 1990
5. 230 kV Line-Naughton to Opal to Shute Creek	Same As #1	November, 1991
6. 230 kV Line-Bridger to Rock Springs	Same As #1	November, 1991

E77803.05A

FALL 1988 MEMORANDUM OF AGREEMENT, IPC/PP&L/UP&L

PACIFIC POWER & LIGHT COMPANY
920 S.W. SIXTH AVENUE • PORTLAND, OREGON 97204 • (503) 243-1122

October 27, 1988

Mr. Lynn Rasband
Utah Power & Light Company
1401 West North Temple Street
Salt Lake City, Utah 84110

Dear Lynn:

Enclosed for your files is an authenticated copy of the fully executed Memorandum of Agreement between Pacific, Utah and Idaho which extends the negotiating period and defines the principles to be contained in a Post Merger Interconnection Agreement.

A meeting with Idaho has been scheduled for November 3, 1988 at 9 am at the Portland Airport-Holiday Inn to continue development of a final agreement. Prior to such meeting I would appreciate any comments you may have relating to our draft "Restated Transmission Services Agreement" of which you are in receipt of.

Very truly yours,

Brian D. Sickels

Brian D. Sickels
Power Marketing Manager

sw

Enclosure

cc: Tom Lockhart-UP&L

TELECOPIER 243-4774 • TWX 910-464-1594

AUTHENTICATED COPY

MEMORANDUM OF AGREEMENT

This is a Memorandum of Agreement ("Memorandum") between PacifiCorp, doing business as Pacific Power & Light Company ("Pacific"), Idaho Power Company ("Idaho"), Utah Power & Light Company ("Utah") and PC/UP&L Merging Corp. ("Merged Company"). This Memorandum commits the parties to negotiate in good faith a definitive "Post-Merger Interconnection Agreement" which incorporates the principles set forth below. Through this Memorandum, the parties also hereby agree that Section 3 of the Agreement Respecting Transmission Facilities and Services dated March 21, 1988 is amended to substitute the date "November 15, 1988" at each place that the date "September 30, 1988" appears in said Section 3.

Principles of Post-Merger Interconnection Agreement

The Post-Merger Interconnection Agreement will provide for what are denominated "East to West Transfer Services" and "Other Services." East to West Transfer Services will be provided independent of whether the proposed merger of Pacific and Utah (the "Merger") is consummated and will be provided for a period coincident with the term of the Agreement for Ownership of the Jim Bridger Project, dated September 22, 1969. Other Services will be provided effective on the date of the consummation of the Merger and shall continue for a period of three years at which time

Idaho's obligation to provide such Other Services shall terminate. The Merged Company will not oppose Idaho's termination of the "Other Services" before any regulatory agency or other forum.

East to West Transfer Services shall consist of Idaho's providing transmission services to Pacific or the Merged Company for the east to west transfer of not more than 1,600 megawatts of power, including the transfer of Pacific's share of the net generation of the Jim Bridger Project for any hour (as adjusted for Pacific's or the Merged Company's share of such Project's transmission line losses) and the transfer of "Other Resources" (power available to Pacific or the Merged Company from any sources other than Jim Bridger). East to West Transfers Services shall not be available for third-party wheeling.

East to West Transfer Services will be provided with the understanding that the 1,600 megawatt transfer level is subject to the capacity of the east-west transmission system across Idaho and with the understanding that at all times, and under any conditions, Idaho shall be entitled to the use of not less than 570 megawatts of westbound capability in its existing western interconnections. It is also recognized that it may be necessary to provide additional reactive support on the Idaho transmission system, as well as an increase in the transfer capability of the Jim Bridger 345 kV system and Idaho's western interconnections, in order to attain at all times the maximum 1,600 megawatt transfer level. In the event Pacific or the Merged Company requests a less-restricted level of service up to 1,600 megawatts, Idaho will determine, in consultation with Pacific or the Merged Company, the requirement for any additional equipment or system modifications to attain such less-restricted service.

Pacific or the Merged Company will make available all power to be transferred under East to West Transfer Services to Idaho over the three Jim Bridger 345 kV transmission lines to the Kinport and Borah Substations. Idaho will accept such power and make an equal amount of power, less Idaho transmission line losses, available for Pacific at Pacific's Midpoint-Summer Lake 500 kV line and at Idaho's existing western interconnections (Enterprise, Divide and LaGrande). Pacific or the Merged Company will make available to Idaho as payment for losses associated with the east to west transfer an amount of power equivalent to 2.8 percent of the incremental amount of such scheduled transfers that are less than or greater than 1,000 megawatt hours per hour except for those amounts of transfers that are below 1,000 megawatts because of a forced outage, mechanical restriction or scheduled maintenance outage of generation or transmission capacity. The parties agree that every three years, or at any time following significant system changes, the loss calculations will be reviewed and appropriately adjusted.

BEST EFFORT

Pacific or the Merged Company will provide hourly preschedules of both Jim Bridger and Other Resource transfers to Idaho on the last work day observed by Pacific or the Merged Company and Idaho prior to the day of delivery. Additionally, Pacific or the Merged Company will provide Idaho with a best-efforts update of the Jim Bridger prescheduled transfer at least 30 minutes prior to the scheduled hour. As soon as possible after the schedule hour, Pacific or the Merged Company will provide Idaho with the adjusted schedule for the Jim Bridger transfers associated with such pre-schedule. The adjusted schedule will be derived by integrating the actual dynamic Jim Bridger schedule over the schedule hour. With regard to Other Resources, Pacific or the Merged Company will provide Idaho with an update of the Other Resource schedule at least 30 minutes prior to the schedule hour. Except as provided for below in regard to Other Services, the updated schedule for Other Resources will be deemed to be the actual schedule for such hour, except that in the event of a forced outage of either transmission or generation capacity, Pacific or the

Merged Company may make an adjustment change to its Other Resource schedule consistent with normally accepted scheduling practices.

"Other Services" shall consist of Idaho providing the Merged Company with such services as it may require in order for the Merged Company to have the right to make bi-directional transfers of up to 600 megawatts between its Wyoming and Utah systems. It is understood that such transfers will be made at the eastern points of delivery as established in the 1974 TFA, 1980 TSA and the 1982 Ben Lomond Agreement. Such 600 megawatts shall include the Merged Company's transfer capability over the Rock Springs-Naughton 230 kV transmission line. No additional equipment or phase-shifters will be required of the Merged Company beyond the existing work being done to upgrade the Wyoming-Utah transfer path to 400 megawatts. The Merged Company shall provide Idaho with the Wyoming-Utah schedules according to normally accepted scheduling practices.

It is understood that these "Other Services" do not provide the right for the Merged Company to make deliveries from its Utah division to Idaho for "Supplemental East to West Transfers". It is also understood that these "Other Services" do not provide for the right for the Merged Company to make deliveries from the Jim Bridger transmission system for "Supplemental Goshen Area Transfers."

In addition to the foregoing, under "Other Services" Idaho will provide up to plus or minus 100 megawatts of dynamic scheduling service (within the overall 1,600 megawatt limit) associated with the Merged Company's east to west transfer of "Other Resources" provided for above. Pacific or the Merged Company shall limit dynamic overlay control in one direction at any time that Idaho Power's operators notify Pacific's or the Merged Company's operators that providing such dynamic service is causing Idaho to forego the opportunity to make use of capacity in its western interconnections. The Other Resource transfer schedule for any hour shall be derived by integrating the actual dynamic schedule over the hour. A signal for determining this dynamic schedule will be provided to Idaho.

Idaho shall be compensated for the services described above as follows:

1. Pacific or the Merged Company shall compensate Idaho for East to West Transfer Service by paying Idaho an amount equal to the compensation that Pacific otherwise would have paid Idaho during any given year under the 1980 Transmission Services Agreement and 1974 TFA except, to the extent that transfers of "Other Resources" are in excess of 350 megawatt

hours per hour and/or 124 average megawatts per Operating Year (September through August), Pacific or the Merged Company shall pay Idaho an additional charge equal to Idaho's then-effective Inter-Company Pool ("ICP") non-firm energy wheeling rate plus .5 mill per kilowatt hour for any such excess transfers. In the event the ICP rate is discontinued, the additional charge shall be calculated by adding .5 mill per kilowatt hour to Idaho's then-effective FERC tariff non-firm energy wheeling rate (mills/kwh) of general applicability.

2. In the event Pacific or the Merged Company requests a less-restricted level of East to West Transfer Service and additional equipment or system modifications are necessary in order to attain such level of service, Pacific or the Merged Company shall pay Idaho for any such equipment or modifications consistent with the use of facilities charge methodology set forth in Exhibit A of the 1980 Transmission Services Agreement.

3. The Merged Company shall pay Idaho a fee at the annual rate of $1,000,000 for Other Services during the three year period of time such services are provided. It is explicitly understood that the $1,000,000 per year charge for these services is a negotiated compromise and does not

reflect the acceptance by any party to this Agreement that it represents the appropriate level of compensation for the services.

The parties to this Memorandum understand and agree that the principles set forth in this Memorandum of Agreement represent broad guidelines which shall provide the parties with the basis for negotiating the specific terms and conditions of the Post-Merger Interconnection Agreement.

PACIFICORP, doing business as
PACIFIC POWER & LIGHT COMPANY

By: ______________________

IDAHO POWER COMPANY

By: ______________________

UTAH POWER & LIGHT COMPANY

By: ______________________

PC/UP&L MERGING CORP.

By: ______________________

I Sally A. Nofziger, do hereby certify that the attached Memorandum of Agreement is a true authenticated copy.

By: Sally A. Nofziger
Sally A. Nofziger

Title: Corporate Secretary

CORPORATE SEAL

UTAH SOUTH BOUNDARY NOMOGRAMS

UTAH SOUTH BOUNDARY NOMOGRAM

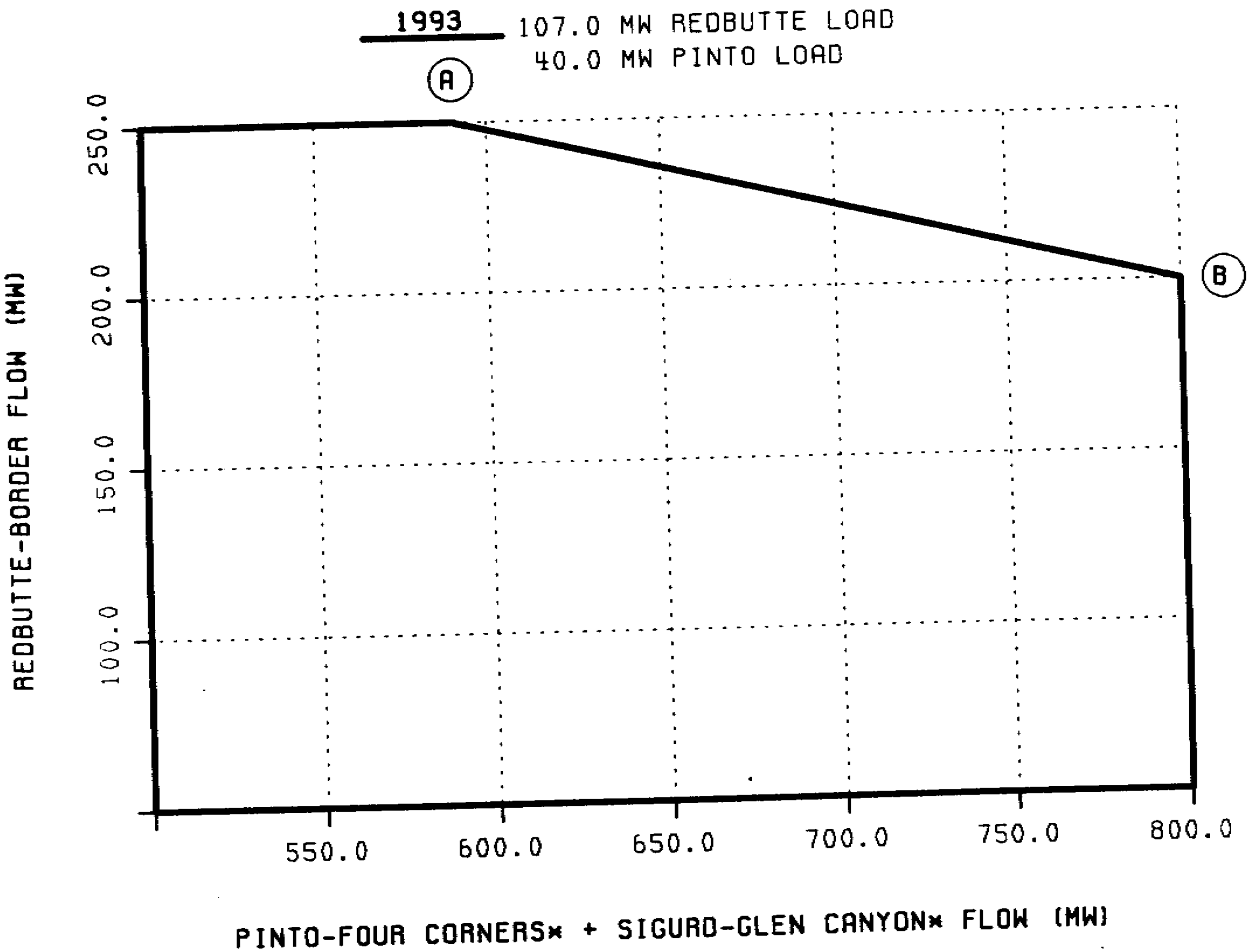
IN JUNE, 1990 THE UTAH SOUTH BOUNDARY WILL CONSIST OF THREE LINES: THE RED BUTTE-BORDER 345 KV LINE, THE SIGURD-GLEN CANYON 230 KV LINE, AND THE PINTO-FOUR CORNERS 345 KV LINE. ALTHOUGH EACH OF THESE LINES HAS AN INDIVIDUAL RATING, THE INTERACTION BETWEEN THEM CAUSES A SIMULTANEOUS LOADING LIMIT WHICH CAN BEST BE ILLUSTRATED BY NOMOGRAMS. THESE NOMOGRAMS ARE BASED ON CERTAIN SIMULTANEOUS FLOWS ON THE THREE LINES AND ARE INCLUDED IN THIS REPORT.

FOR THE NORTH TO SOUTH FLOWS, A NOMOGRAM EXISTS BETWEEN THE RED BUTTE-HARRY ALLEN 345 KV LINE AND THE OTHER TWO LINES. WHEN THE RED BUTTE 345 KV LINE IS FULLY LOADED TO 250 MW THE FLOWS ON THE OTHER TWO LINES CAN BE ONLY 589 MW (POINT A). HOWEVER, WHEN THE REDBUTTE LINE FLOW IS 200 MW OR LESS, THE FLOW ON THE OTHER TWO LINES CAN BE AS HIGH AS THEIR SIMULTANEOUS MAXIMUM OF 800 MW (POINT B). POINTS A AND B ARE DETERMINED BY POWER FLOW AND STABILITY STUDIES WHICH DEMONSTRATE THAT FOR THE WORST SINGLE CONTINGENCY, SYSTEM STABILITY IS MAINTAINED AND POST-DISTURBANCE SYSTEM VOLTAGES ARE ACCEPTABLE.

FOR THE SOUTH TO NORTH FLOWS, A NOMOGRAM EXISTS BETWEEN THE GLEN CANYON-SIGURD 230 KV LINE AND THE FOUR CORNERS-PINTO 345 KV LINE WITH THE HARRY ALLEN-RED BUTTE 345 KV LINE AT 250 MW. IN THIS NOMOGRAM, WHEN THE GLEN CANYON-SIGURD LINE IS LOADED TO 270 MW, THE FOUR CORNERS-PINTO LINE CAN BE LOADED TO 550 MW (POINT C). HOWEVER, IF THE GLEN CANYON-SIGURD LINE IS LOADED TO 250 MW OR LESS, THE FOUR CORNERS-PINTO LINE CAN BE LOADED TO ITS FULL 600 MW RATING (POINT D). SEVERAL PLOTS AND GRAPHS FROM THE STUDIES WHICH DETERMINED THESE NOMOGRAMS ARE ATTACHED.

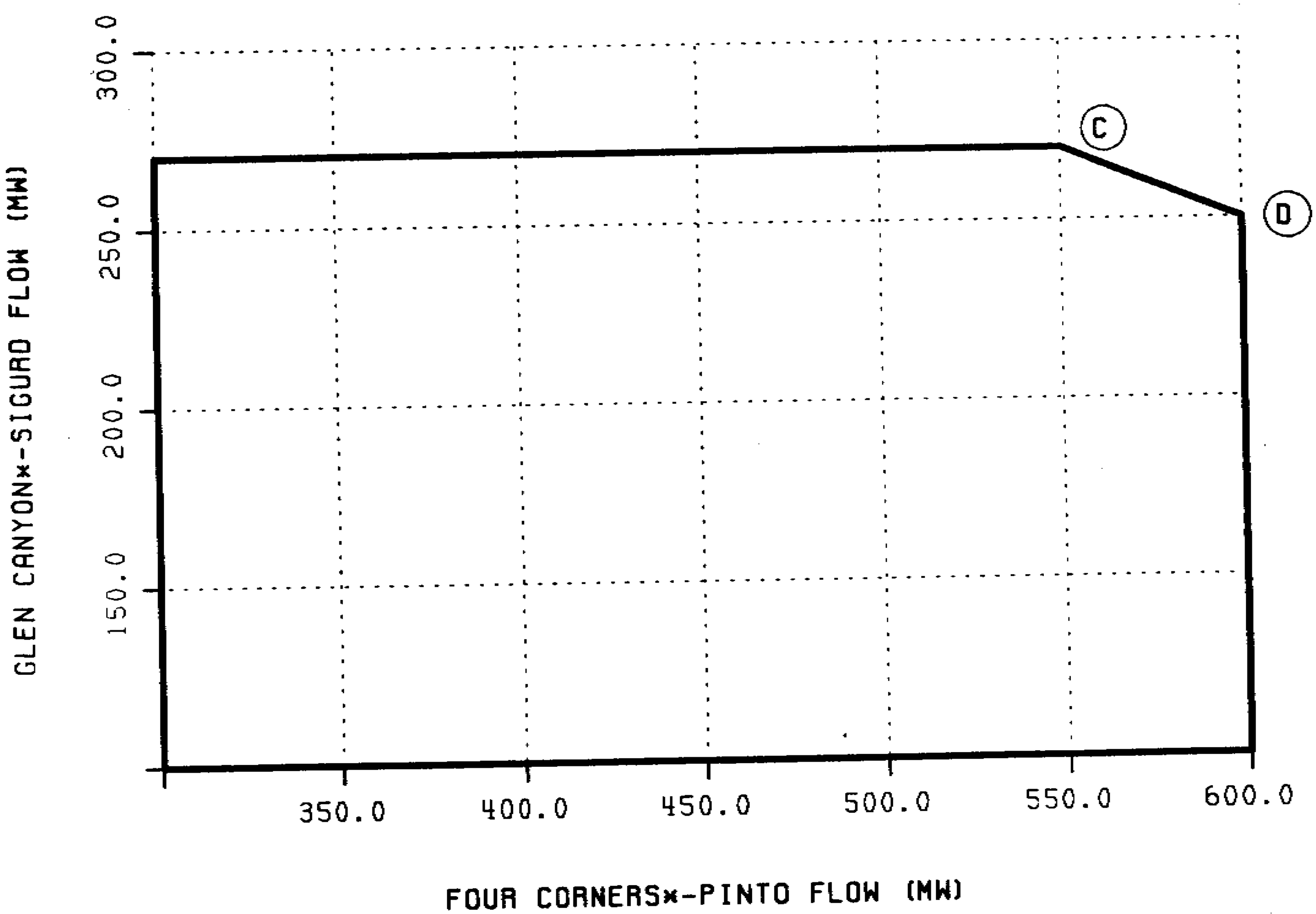
UTAH SOUTH BOUNDARY NOMOGRAM

NORTH TO SOUTH



UTAH SOUTH BOUNDARY NOMOGRAM
SOUTH TO NORTH

BORDER-REDBUTTE FLOW = 250 MW



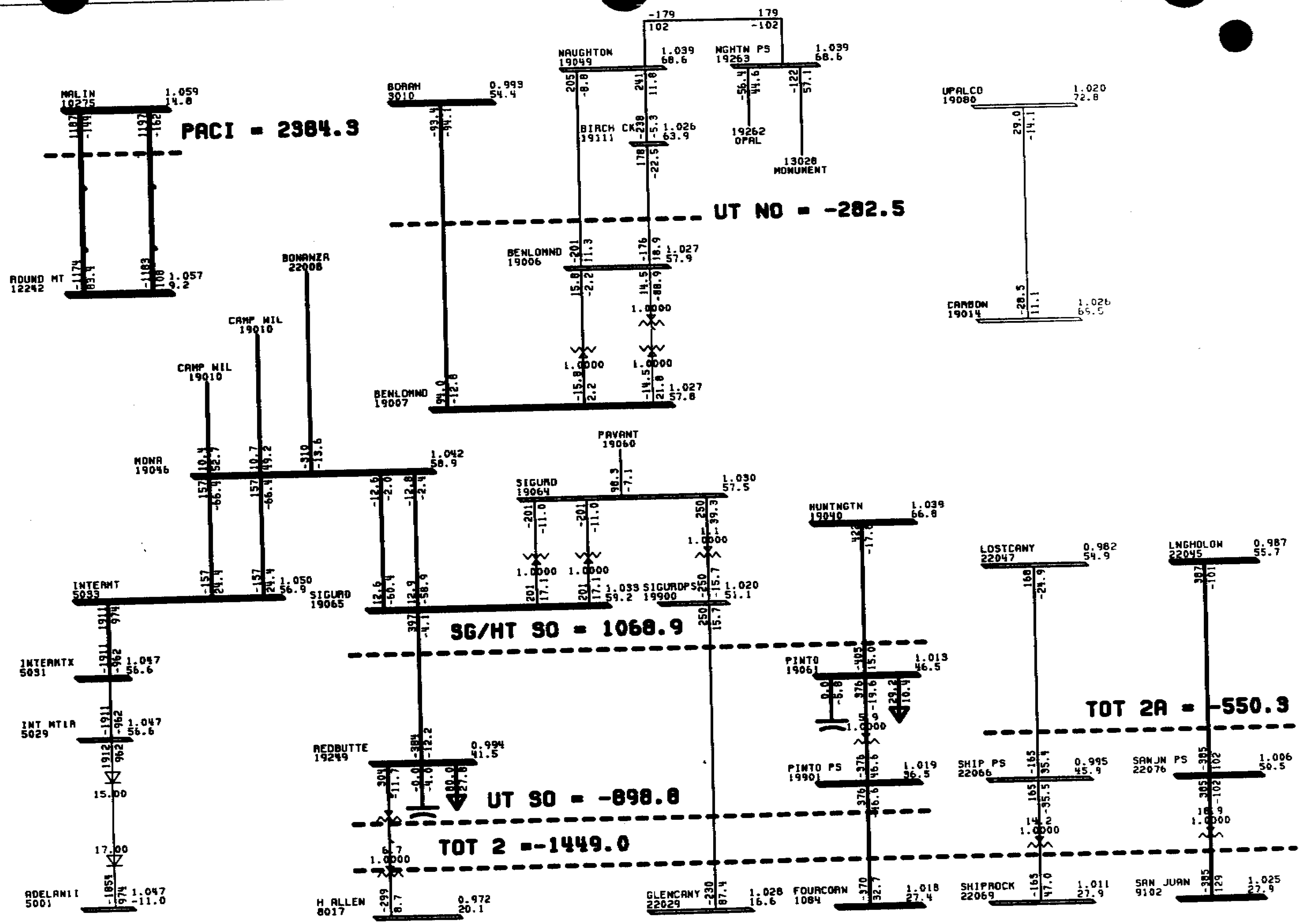
POINT A STUDIES - NORTH TO SOUTH

POINT A ON THE NORTH TO SOUTH NOMOGRAM IS DETERMINED BY THE STABILITY RESULTS OF CASE HNTPNTO17 USING POWER FLOW CASE ESTC17. THE UTAH SOUTHERN BOUNDARY FLOWS IN THIS POWER FLOW ARE: 299 MW FOR THE RED BUTTE-HARRY ALLEN 345 KV LINE, AND A COMBINED FLOW OF 600 MW ON THE PINTO-FOUR CORNERS 345 KV LINE AND THE SIGURD-GLEN CANYON 230 KV LINE. THE LOAD REPRESENTED AT RED BUTTE AND PINTO ARE 80 MW AND 29 MW RESPECTIVELY. THIS POWER FLOW CASE IS DERIVED FROM THE WSCC 1990LS2 BASE CASE WHICH HAS BEEN MODIFIED TO ADD THE UTAH PHASE SHIFTING TRANSFORMERS AND TO ACHIEVE THE DESIRED LINE FLOWS. THE WORST SINGLE CONTINGENCY REPRESENTED IN STABILITY CASE HNTPNTO17 IS THE LOSS OF THE HUNTINGTON-PINTO 345 KV LINE.

THE STUDY RESULTS SHOW THAT FOR THIS DISTURBANCE, SYSTEM STABILITY IS MAINTAINED WHILE THE LOWEST FIRST-SWING VOLTAGE (.79 PER UNIT) OCCURS AT THE HARRY ALLEN 345 KV BUS. IN ORDER FOR THE NOMOGRAM TO REPRESENT THE 1993 TIME PERIOD, ALLOWANCES NEED TO BE MADE FOR DIFFERENT LOADS FORECASTED FOR RED BUTTE AND PINTO. THE 1993 FORECASTED PEAK LOADS ARE 107 MW FOR RED BUTTE AND 40 MW FOR PINTO. BECAUSE OF THESE HIGHER LOADS THE FLOW ON THE RED BUTTE-HARRY ALLEN 345 KV LINE SHOULD BE REDUCED TO 272 MW AND THE COMBINED FLOW ON THE SIGURD-GLEN LINE PLUS THE PINTO-FOUR CORNERS LINE SHOULD BE REDUCED TO 589 MW IN ORDER TO GIVE THE SAME STABILITY RESULTS. ALSO, IN ORDER TO ACHIEVE THE VOLTAGE CRITERIA OF .80 MINIMUM SWING VOLTAGE, A FURTHER REDUCTION IN THE RED BUTTE-HARRY ALLEN FLOW IS REQUIRED. SINCE THE MAXIMUM AMOUNT OF POWER THAT NEVADA POWER COMPANY CAN TAKE ON THIS LINE IS 250 MW, SENSITIVITY STUDIES SHOW THAT THE 22 MW REDUCTION IN LINE FLOW ON THE REDBUTTE-HARRY ALLEN LINE WOULD IMPROVE THE MINIMUM SWING VOLTAGE ABOVE THE .80 MINIMUM. PLOTS ARE ATTACHED WHICH SHOW THE STUDY RESULTS. THEREFORE THE LINE FLOWS FOR POINT A ON THE NORTH TO SOUTH NOMOGRAM ARE:

RED BUTTE TO THE BORDER = 250 MW

PINTO-FOUR CORNERS + SIGURD-GLEN CANYON FLOW = 589 MW.



ESTC17-M90LS2-RMV CRG-BNZA LN. ADD UT PSHFTRS.
SIG*-RBUT = 397MW, SIG*-GLEN + HNTG*-PNTO = 670MW
FRI DEC 16, 1988 09:14

KV: ≤138 , ≤230 , ≤345

BUS - VOLTAGE (PU) / ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

ESTC17-M90LS2-RMV CRG-BNZA LN. ADD UT PSHFTRS.
SIG*-RBUT = 397MW, SIG*-GLEN + HNTG*-PNTO = 670MW
3 PH FLT ON HNT-PNTO 345 LINE. RMV FLT/LINE @ 4 CY.

FILE: HNTPNTO17.OUT

CHNL# 71: [ANG1GLENCAN2] 150.00 -150.0

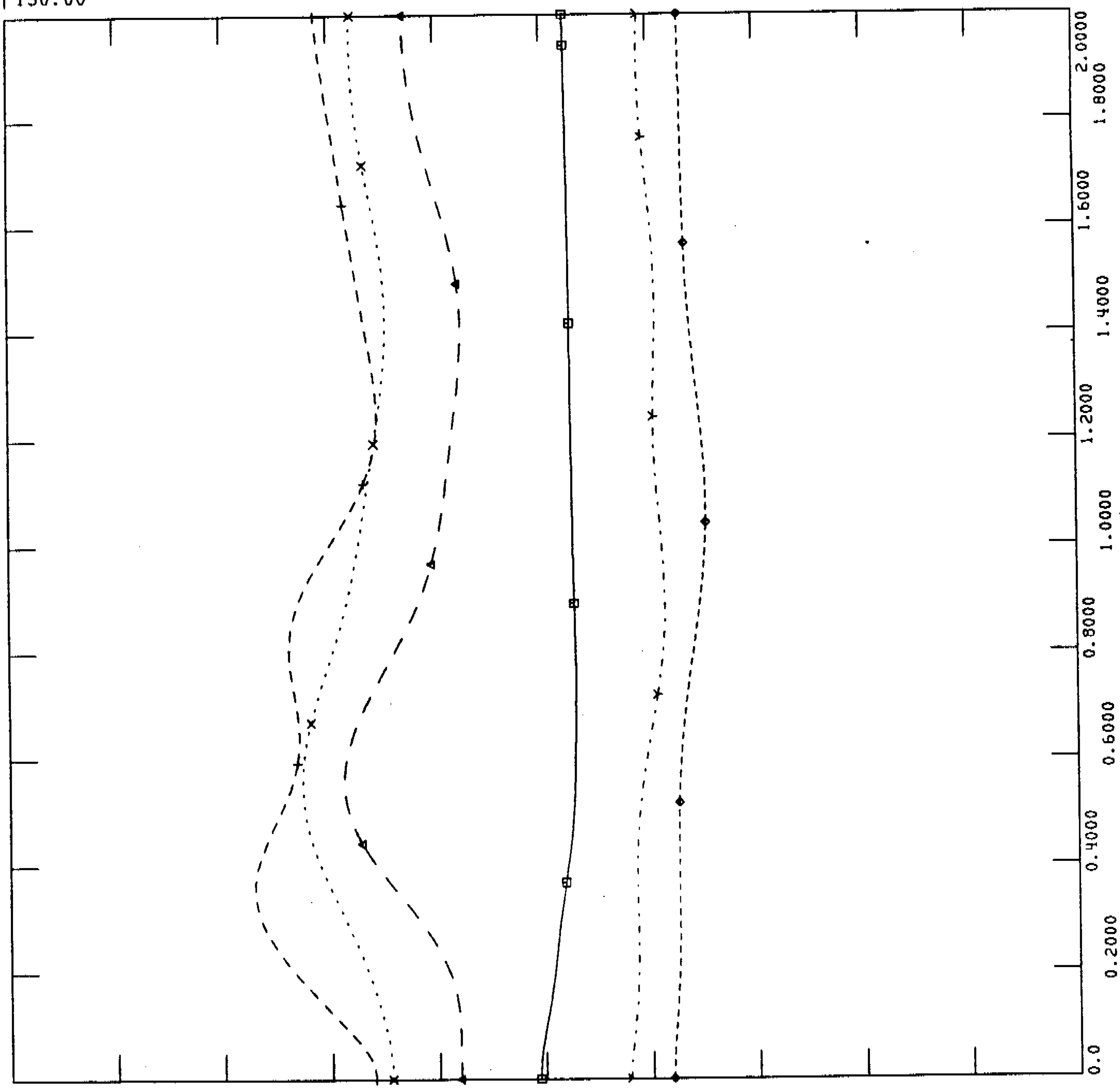
CHNL# 59: [ANG1NAUGT G3] 150.00 -150.0

CHNL# 50: [ANG1EHUNTR 1] 150.00 -150.0

CHNL# 22: [ANG1RDGR4GEN] 150.00 -150.0

CHNL# 16: [ANG1INTERM1G] 150.00 -150.0

CHNL# 1: [ANGHFCNGN4CC] 150.00 -150.0

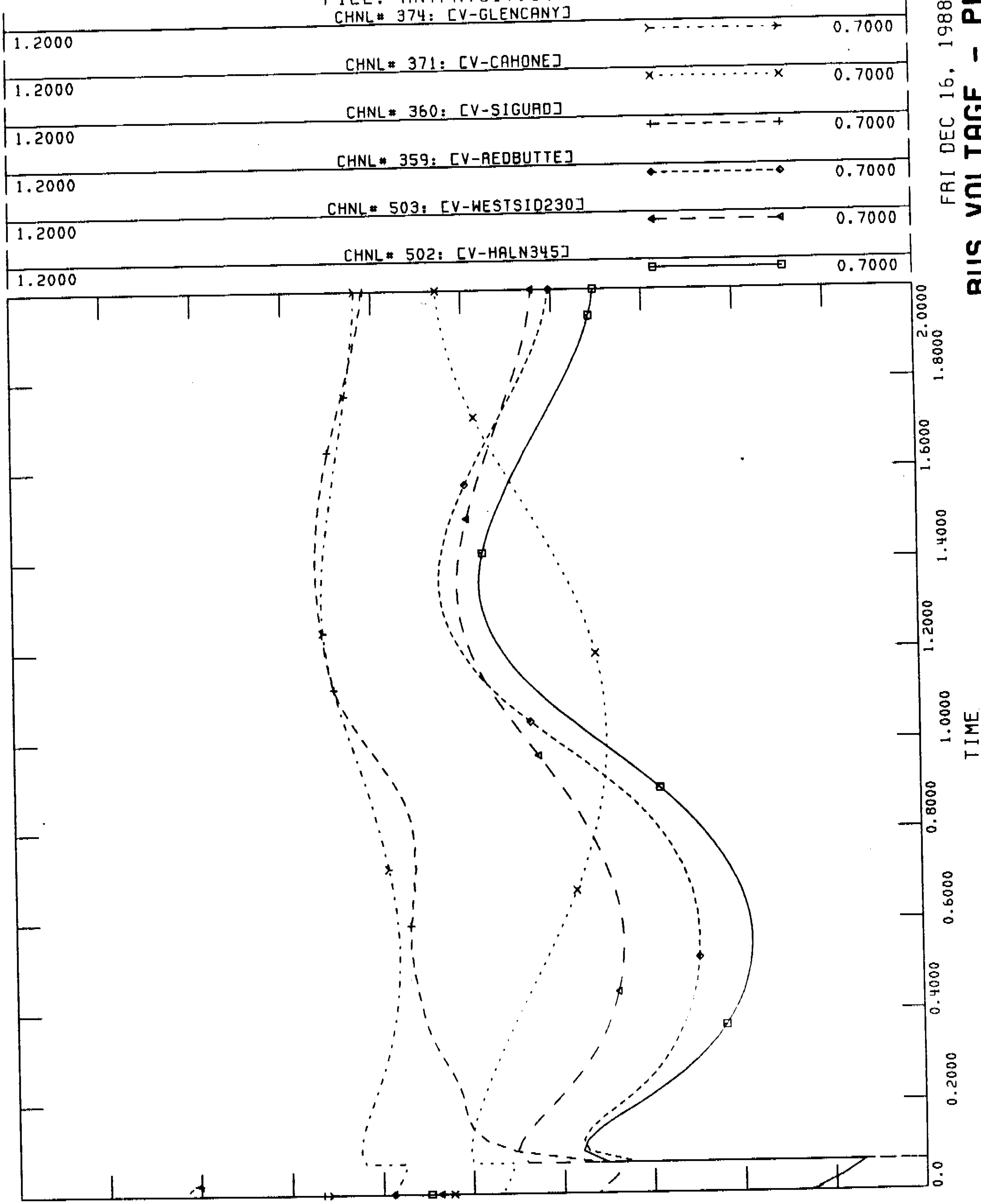


FRI DEC 16, 1988 15:18

REL. ROTOR ANG. - PLOT 1

ESTC17-M90LS2-RMV CRG-BNZA LN. ADD UT PSHFTRS.
SIG*-RBUT = 397MW, SIG*-GLEN + HNTG*-PNTO = 670MW
3 PH FLT ON HNT-PNTO 345 LINE. RMV FLT/LINE @ 4 CY.

FILE: HNTPNTO17.OUT



FRI DEC 16, 1988 15:05

BUS VOLTAGE - PLOT 2

ESTC17-M90LS2-RMV CRG-BNZA LN. ADD UT PSHFTRS.
SIG*-RBUT = 397MW, SIG*-GLEN + HNTG*-PNTO = 670MW
3 PH FLT ON HNT-PNTO 345 LINE. RMV FLT/LINE @ 4 CY.

FRI DEC 16, 1988 15:07

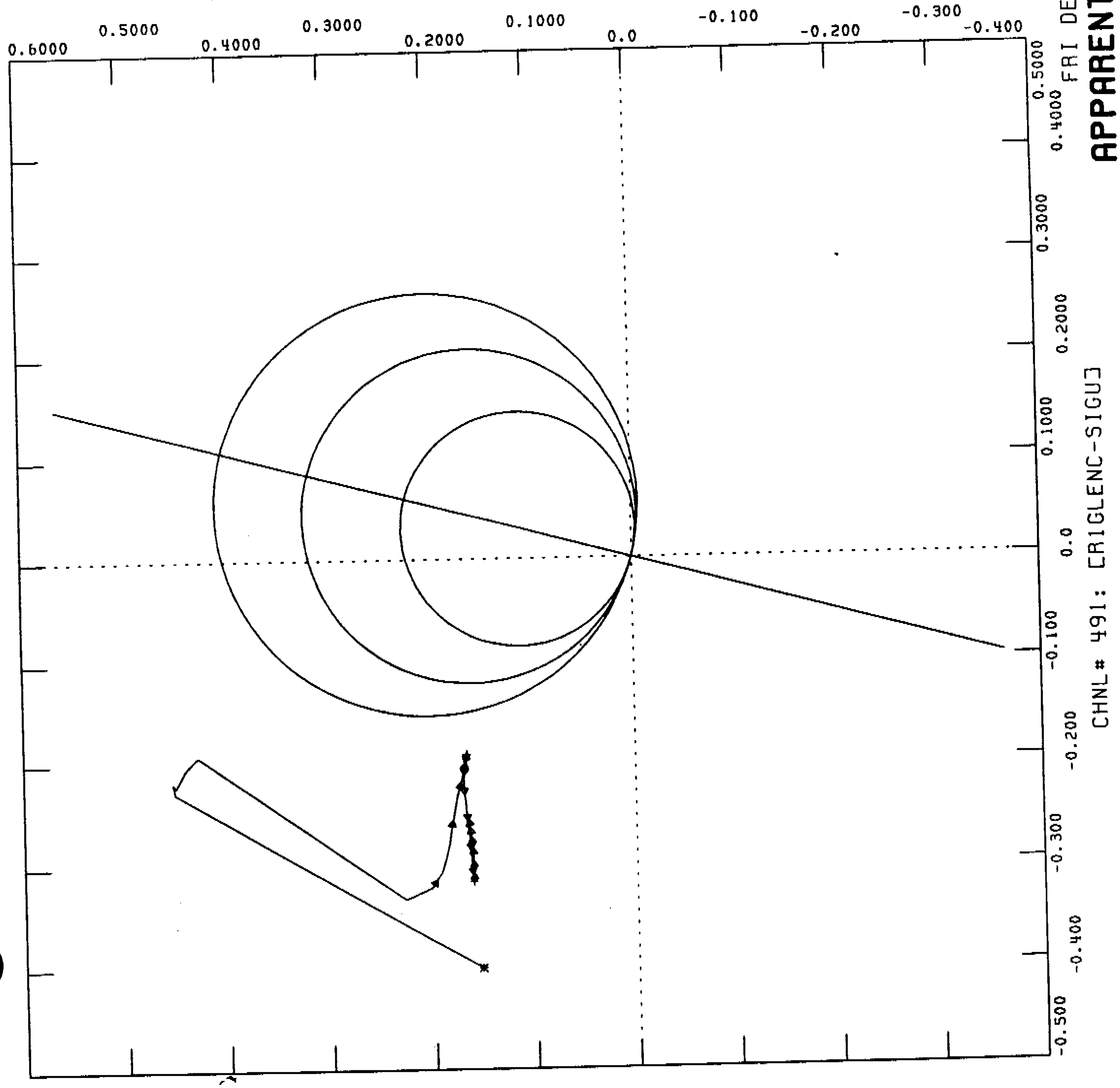
APPARENT IMPEDANCE - PLOT 3

FILE: HNTPNTO17.OUT

RELAY: DISTR

TSTART: 0.0 TSTOP: 2.0 TIC INCREMENT: 0.1

CHNL# 492: [X1GLENC-SIGU]



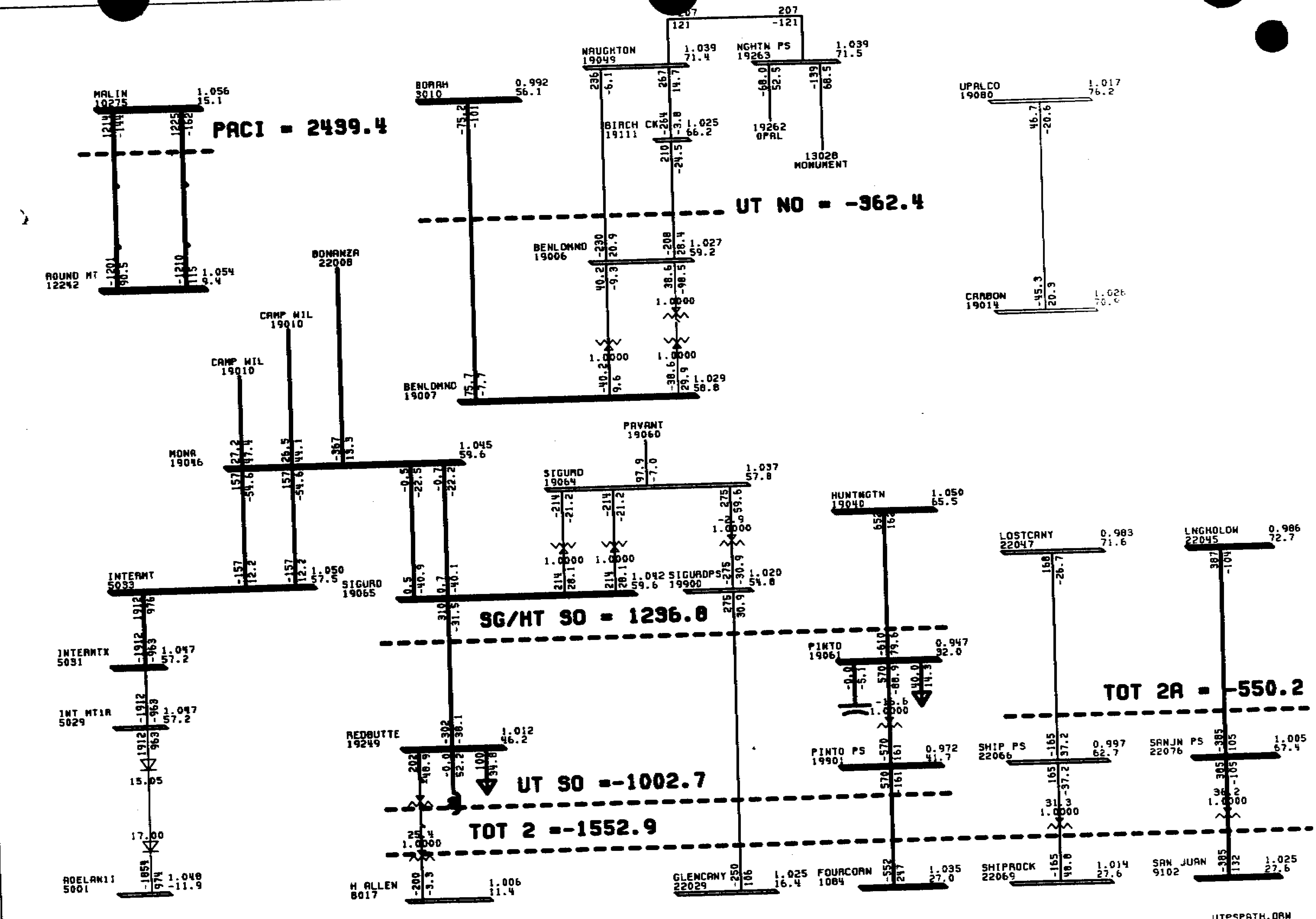
POINT B STUDIES - NORTH TO SOUTH

POINT B ON THE NORTH TO SOUTH NOMOGRAM IS DETERMINED BY THE STABILITY RESULTS OF CASE HNTPNTO15 USING POWER FLOW CASE ESTC15. THE UTAH SOUTHERN BOUNDARY FLOWS IN THIS POWER FLOW ARE: 200 MW FOR THE RED BUTTE-HARRY ALLEN 345 KV LINE, AND A COMBINED FLOW OF 802 MW ON THE PINTO-FOUR CORNERS 345 KV LINE AND THE SIGURD-GLEN CANYON 230 KV LINE. THE LOAD REPRESENTED AT RED BUTTE AND PINTO ARE 100 MW AND 40 MW RESPECTIVELY. THIS POWER FLOW CASE IS DERIVED FROM THE WSCC 1990LS2 BASE CASE WHICH HAS BEEN MODIFIED TO ADD THE UTAH PHASE SHIFTING TRANSFORMERS AND TO CHANGE SCHEDULES TO ACHIEVE THE DESIRED LINE FLOWS. THE WORST SINGLE CONTINGENCY REPRESENTED IN STABILITY CASE HNTPNTO15 IS THE LOSS OF THE HUNTINGTON-PINTO 345 KV LINE.

THE STUDY RESULTS SHOW THAT FOR THIS DISTURBANCE, SYSTEM STABILITY IS MAINTAINED WHILE THE LOWEST FIRST-SWING VOLTAGE (.81 PER UNIT) OCCURS AT THE HARRY ALLEN 345 KV BUS. IN ORDER FOR THE NOMOGRAM TO REPRESENT THE 1993 TIME PERIOD, ALLOWANCES NEED TO BE MADE FOR DIFFERENT LOADS FORECASTED FOR RED BUTTE. THE 1993 FORECASTED PEAK LOAD FOR RED BUTTE IS 107 MW. THIS ADDITIONAL LOAD WOULD NOT CAUSE THE FIRST-SWING VOLTAGE TO DROP BELOW THE .80 PER UNIT ACCEPTABLE LEVEL. THEREFORE THE LINE FLOWS FOR POINT B ON THE NORTH TO SOUTH NOMOGRAM ARE:

RED BUTTE TO THE BORDER = 200 MW

PINTO-FOUR CORNERS + SIGURD-GLEN CANYON FLOW = 802 MW.



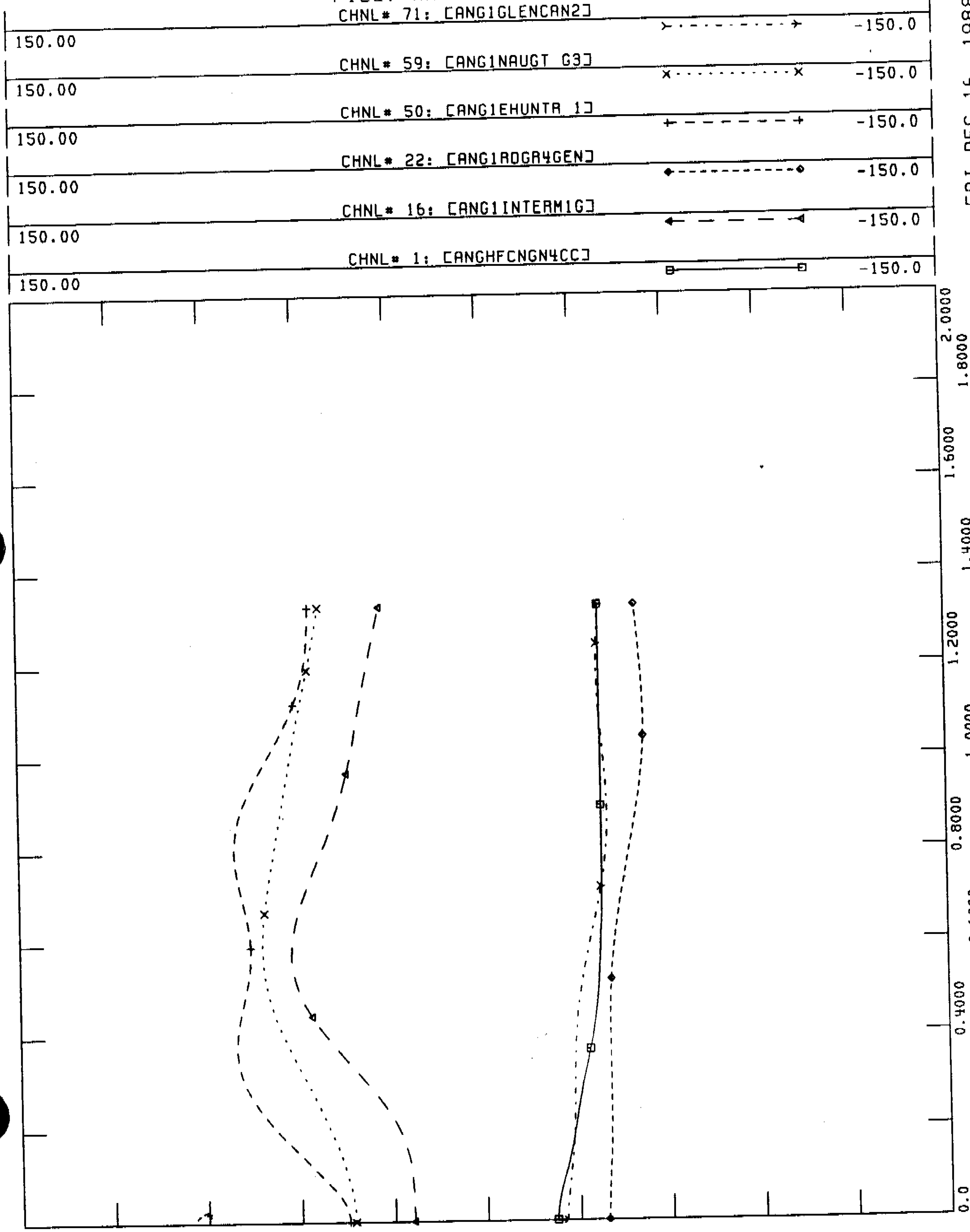
ESTC15-M90LS2-RMV CRG-BNZA 345 LN. ADD UTAH PS.
SIG-ABUT = 310MW, SIG-GLEN = 275MW, HNTG-PNTO = 650MW
THU DEC 15, 1988 14:33

KV: ≤138 , ≤230 , ≤345

BUS - VOLTAGE (PU) /ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

ESTC15-M90LS2-RMV CRG-BNZA 345 LN. ADD UTAH PS.
SIG-RBUT = 310MW, SIG-GLEN = 275MW, HNTG-PNTO = 650MW
3 PH FLT ON HNT-PNTO 345 LINE. RMV FLT/LINE @ 4 CY.

FILE: HNTPNTO15.OUT

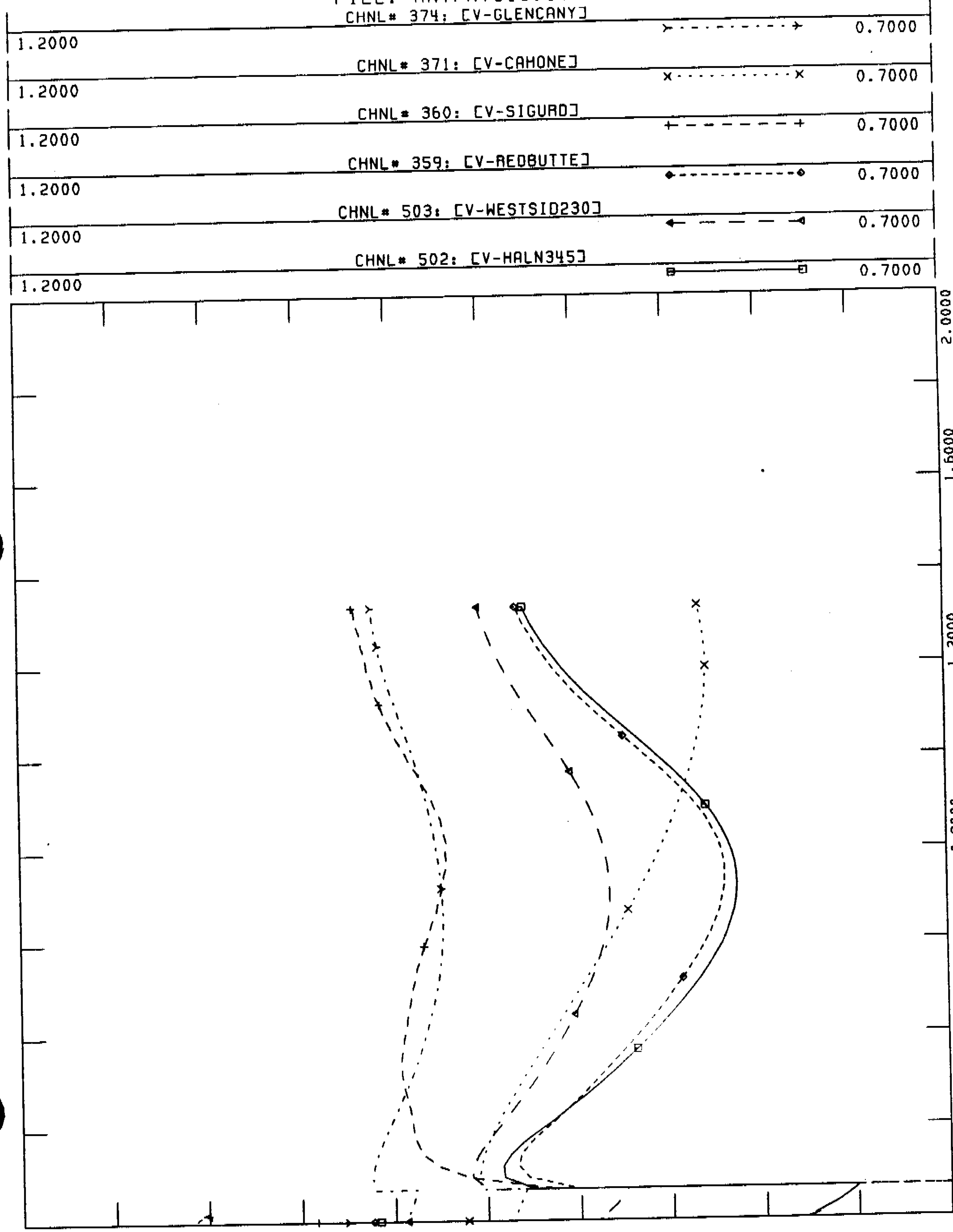


FRI DEC 16, 1988 15:16

REL. ROTOR ANG.- PLOT 4

ESTC15-M90LS2-RMV CRG-BNZA 345 LN. ADD UTAH PS.
SIG-RBUT = 310MW, SIG-GLEN = 275MW, HNTG-PNTO = 650MW
3 PH FLT ON HNT-PNTO 345 LINE. RMV FLT/LINE @ 4 CY.

FILE: HNTPNTO15.OUT



FRI DEC 16, 1988 15:12

BUS VOLTAGE - PLOT 5

ESTC15-M90LS2-RMV CRG-BNZA 345 LN. ADD UTAH PS.
SIG-RBUT = 310MW, SIG-GLEN = 275MW, HNTG-PNTO = 650MW
3 PH FLT ON HNT-PNTO 345 LINE. RMV FLT/LINE @ 4 CY.

FRI DEC 16, 1988 15:09

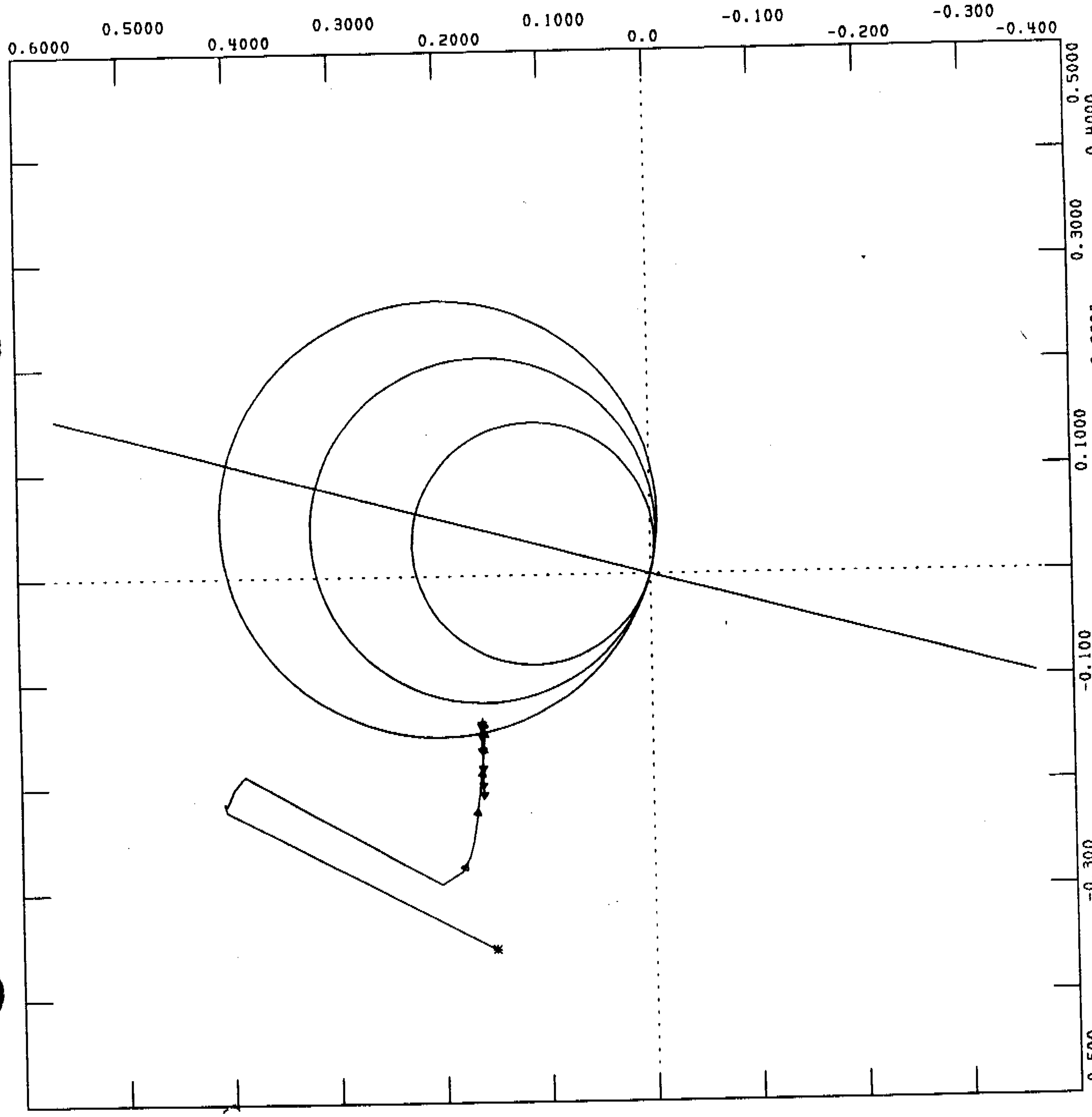
APPARENT IMPEDANCE - PLOT 6

FILE: HNTPNTO15.OUT

RELAY: DISTR

TSTART: 0.0 TSTOP: 2.0 TIC INCREMENT: 0.1

CHNL# 492: [X1GLENC-SIGU]



POINT C STUDIES - SOUTH TO NORTH

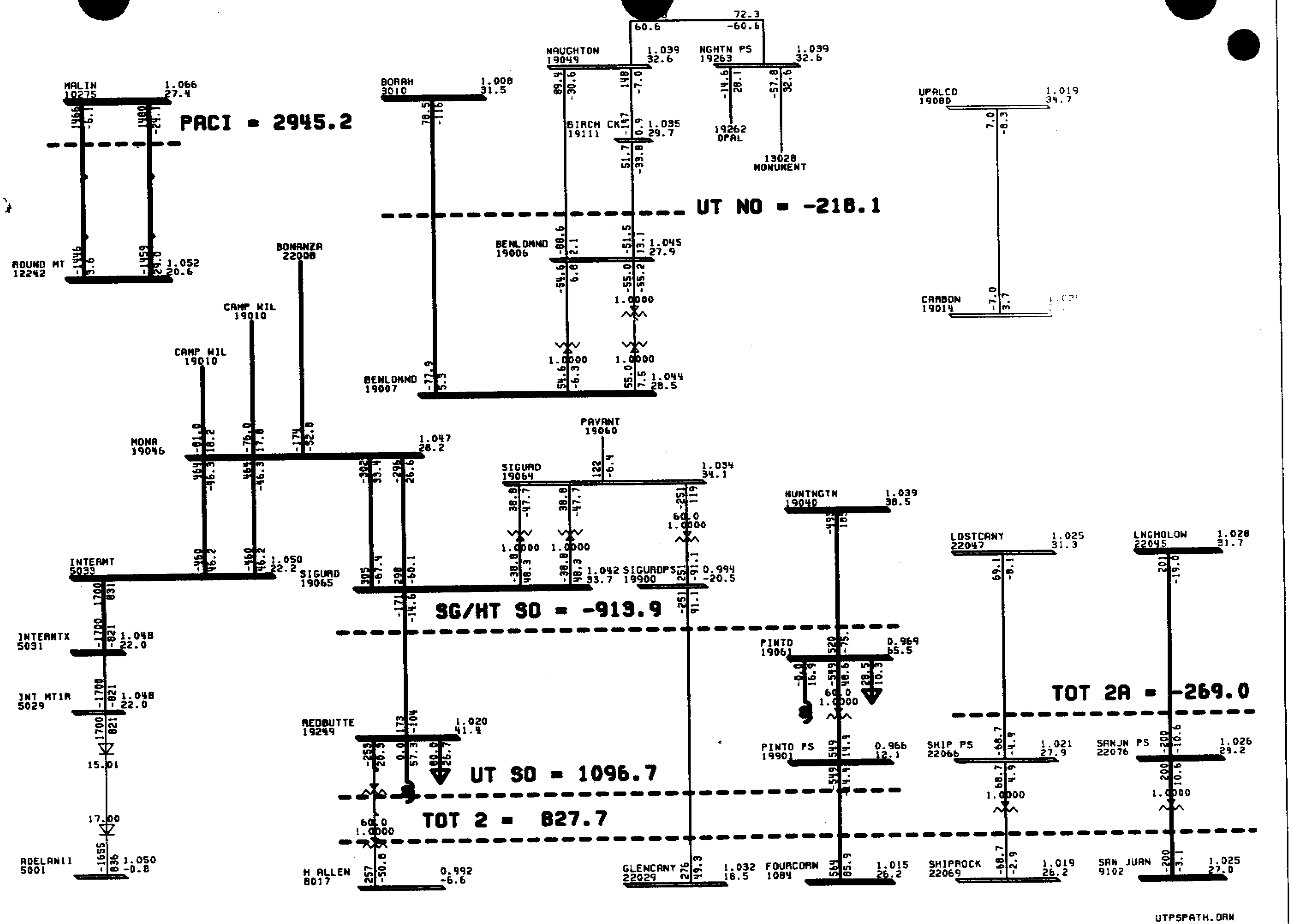
POINT C ON THE SOUTH TO NORTH NOMOGRAM IS DETERMINED BY THE STABILITY RESULTS OF CASE [illegible]PNTO2 USING POWER FLOW CASE SONO2. THE UTAH SOUTHERN BOUNDARY FLOWS IN THIS POWER FLOW ARE: [illegible] MW FOR THE HARRY ALLEN-RED BUTTE 345 KV LINE, AND A FLOW OF 564 MW ON THE FOUR CORNERS-PINTO 345 KV LINE AND 276 MW ON THE GLEN CANYON-SIGURD 230 KV LINE. THIS POWER FLOW CASE IS DERIVED FROM THE WSCC 1990LS2 BASE CASE WHICH HAS BEEN MODIFIED TO ADD THE UTAH PHASE SHIFTING TRANSFORMERS AND TO CHANGE SCHEDULES TO ACHIEVE THE DESIRED LINE FLOWS. THE WORST SINGLE CONTINGENCY REPRESENTED IN STABILITY CASE 4CNPNTO2 IS THE LOSS OF THE FOUR CORNERS-PINTO 345 KV LINE.

THE STUDY RESULTS SHOW THAT FOR THIS DISTURBANCE, SYSTEM STABILITY IS MAINTAINED WHILE THE LOWEST FIRST-SWING VOLTAGE (.82 PER UNIT) OCCURS AT THE HARRY ALLEN 230 KV BUS. HOWEVER, THIS CASE IS MARGINAL BECAUSE OF THE POSSIBILITY OF TRIPPING THE LINE PROTECTION RELAYS AT GLEN CANYON. SENSITIVITY STUDIES SHOW THAT BY REDUCING THE GLEN CANYON-SIGURD FLOW TO 270 MW, THE FOURCORNERS-PINTO FLOW DOWN TO 550 MW, AND THE HARRY ALLEN-RED BUTTE LINE TO ITS MAXIMUM OF 250 MW, THE RESULTS WOULD BE ACCEPTABLE. THEREFORE, THE LINE FLOWS FOR POINT C ON THE SOUTH TO NORTH NOMOGRAM ARE:

FOUR CORNERS-PINTO = 550 MW

GLEN CANYON-SIGURD = 270 MW

BORDER-RED BUTTE = 250 MW

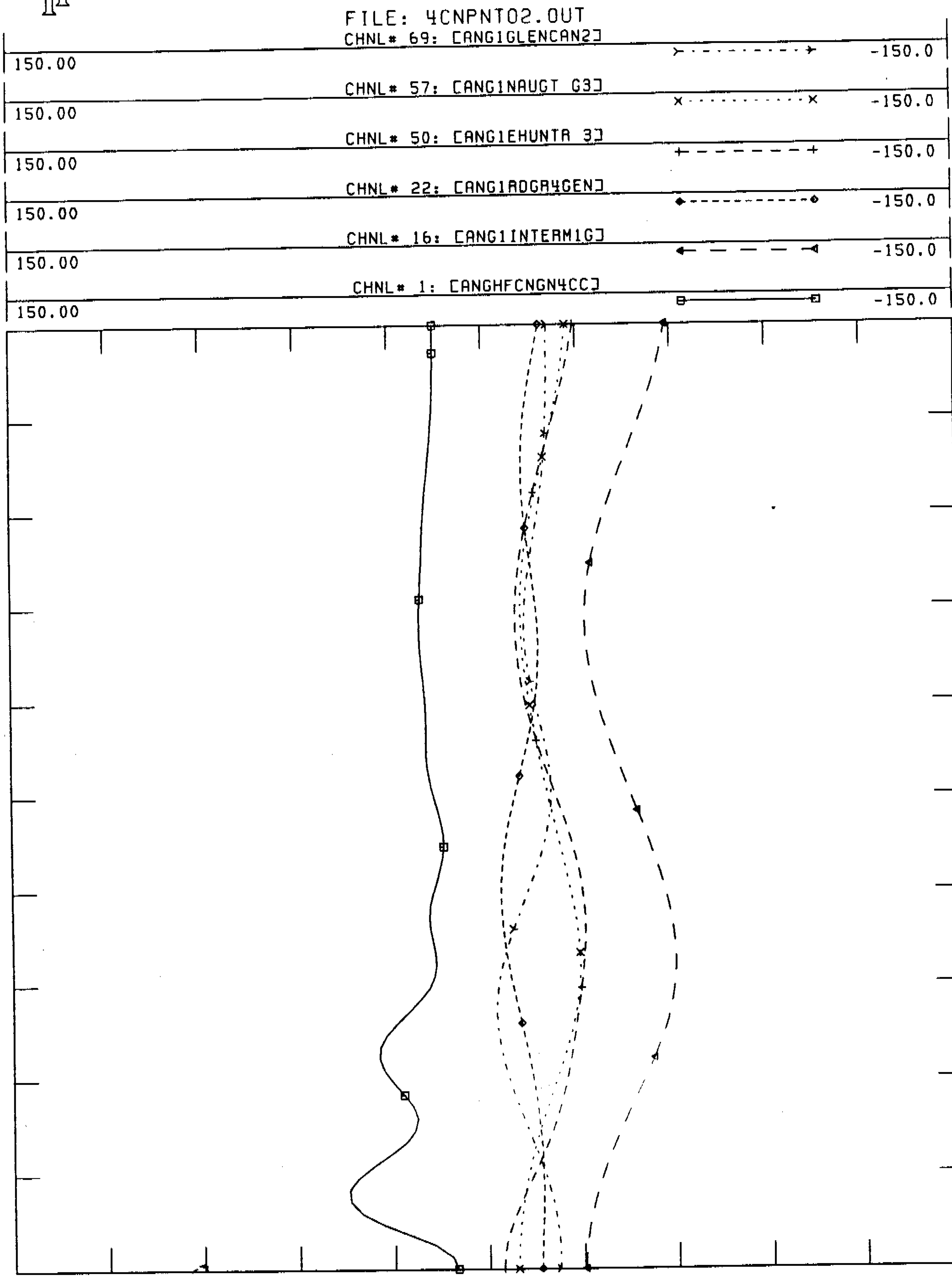


SON02-M90LSP1-ADD NEV TIE, RMV CRG-BNZA 345 LN. UTAH
PS @ 60 DG. HALN-RBUT=257, GLN-SIG=276, 4CRN-PNTO=564
FRI DEC 16, 1988 16:07

KV: ≤138 , ≤230 , ≤345

BUS - VOLTAGE (PU)/ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

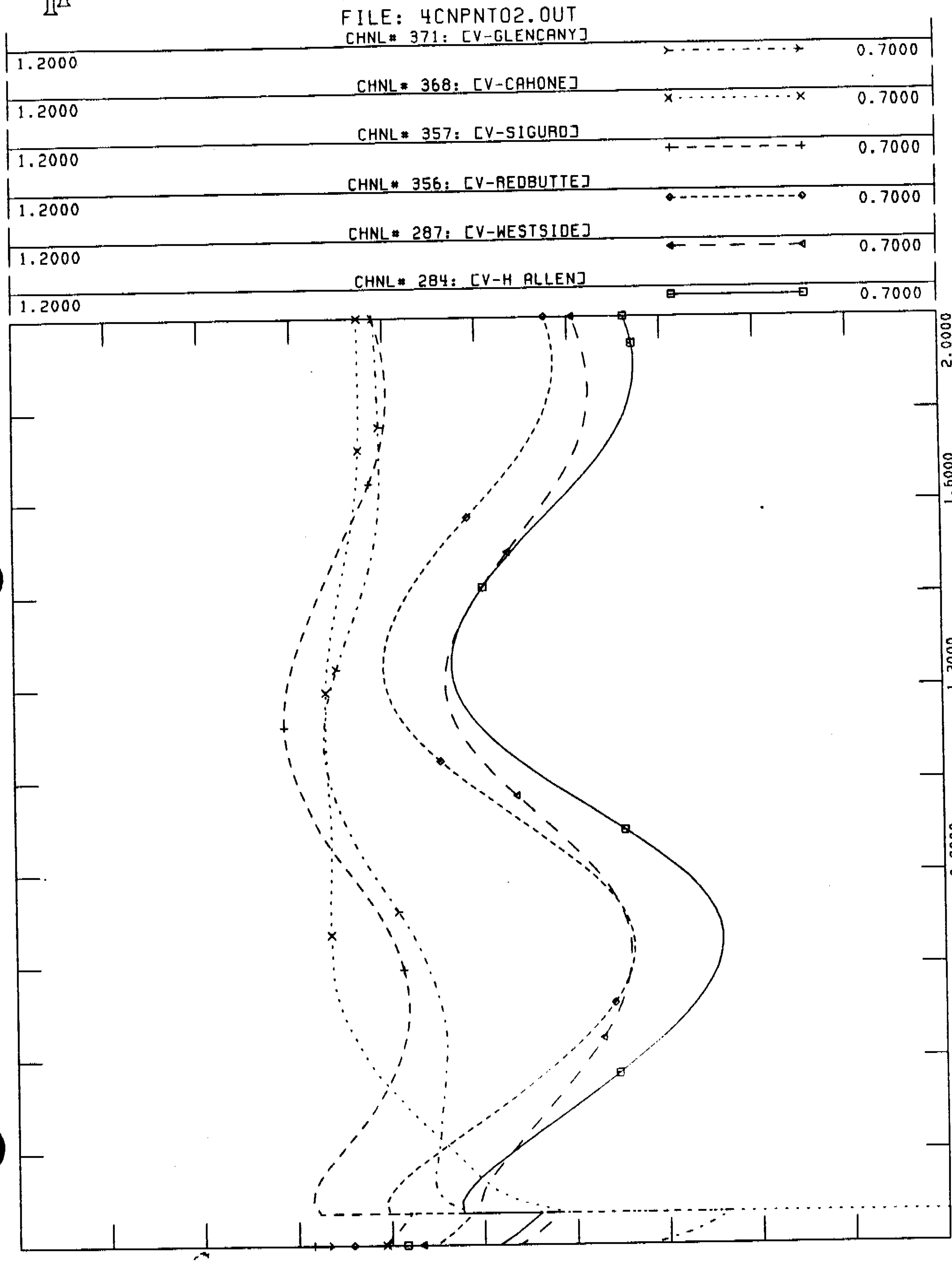
SONO2-M90LSP1-ADD NEV TIE, RMV CRG-BNZA 345 LN. UTAH
PS @ 60 DG. HALN-ABUT=257, GLN-SIG=276, 4CRN-PNTO=564
3 PH FLT ON 4CRN-PNTO 345 LINE. RMV FLT/LINE @ 4 CY.



FRI DEC 16, 1988 16:15

REL. ROTOR ANG. - PLOT 7

SON02-M90LSP1-ADD NEV TIE, RMV CRG-BNZA 345 LN. UTAH
PS @ 60 DG. HALN-ABUT=257, GLN-SIG=276, 4CRN-PNTO=564
3 PH FLT ON 4CRN-PNTO 345 LINE. RMV FLT/LINE @ 4 CY.



FRI DEC 16, 1988 16:16

BUS VOLTAGE - PLOT 8

SONO2-M90LSP1-ADD NEV TIE, RMV CRG-BNZA 345 LN. UTAH
PS @ 60 DG. HALN-RBUT=257, GLN-SIG=276, 4CRN-PNTO=564
3 PH FLT ON 4CRN-PNTO 345 LINE. RMV FLT/LINE @ 4 CY.

APPARENT IMP.- PLOT 9

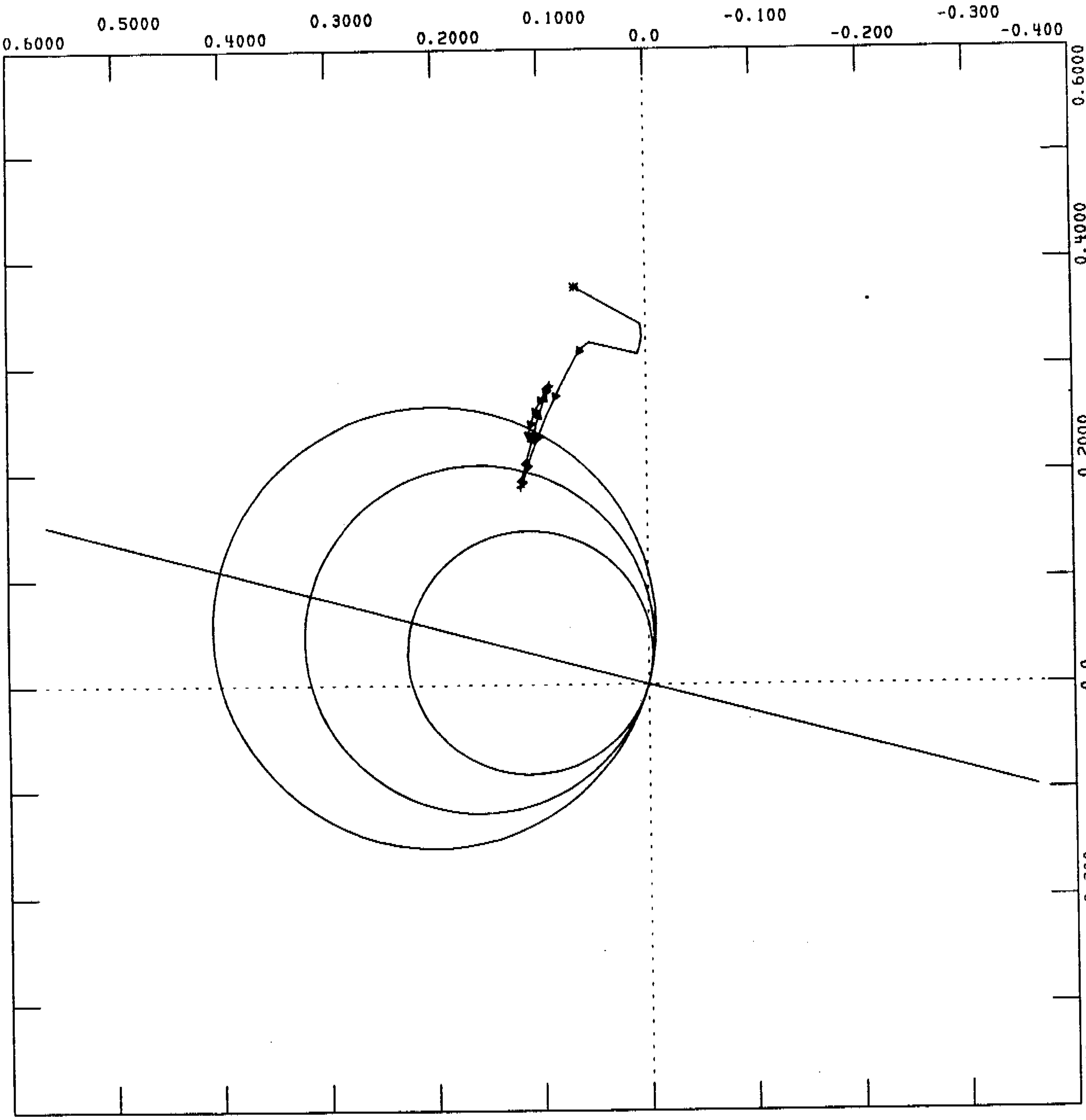
FRI DEC 16, 1988 15:56

FILE: 4CNPNTO2.OUT

RELAY: DISTR

TSTART: 0.0 TSTOP: 2.0 TIC INCREMENT: 0.1

CHNL# 486: [X1GLEN-SIGPS]



POINT D STUDIES - SOUTH TO NORTH

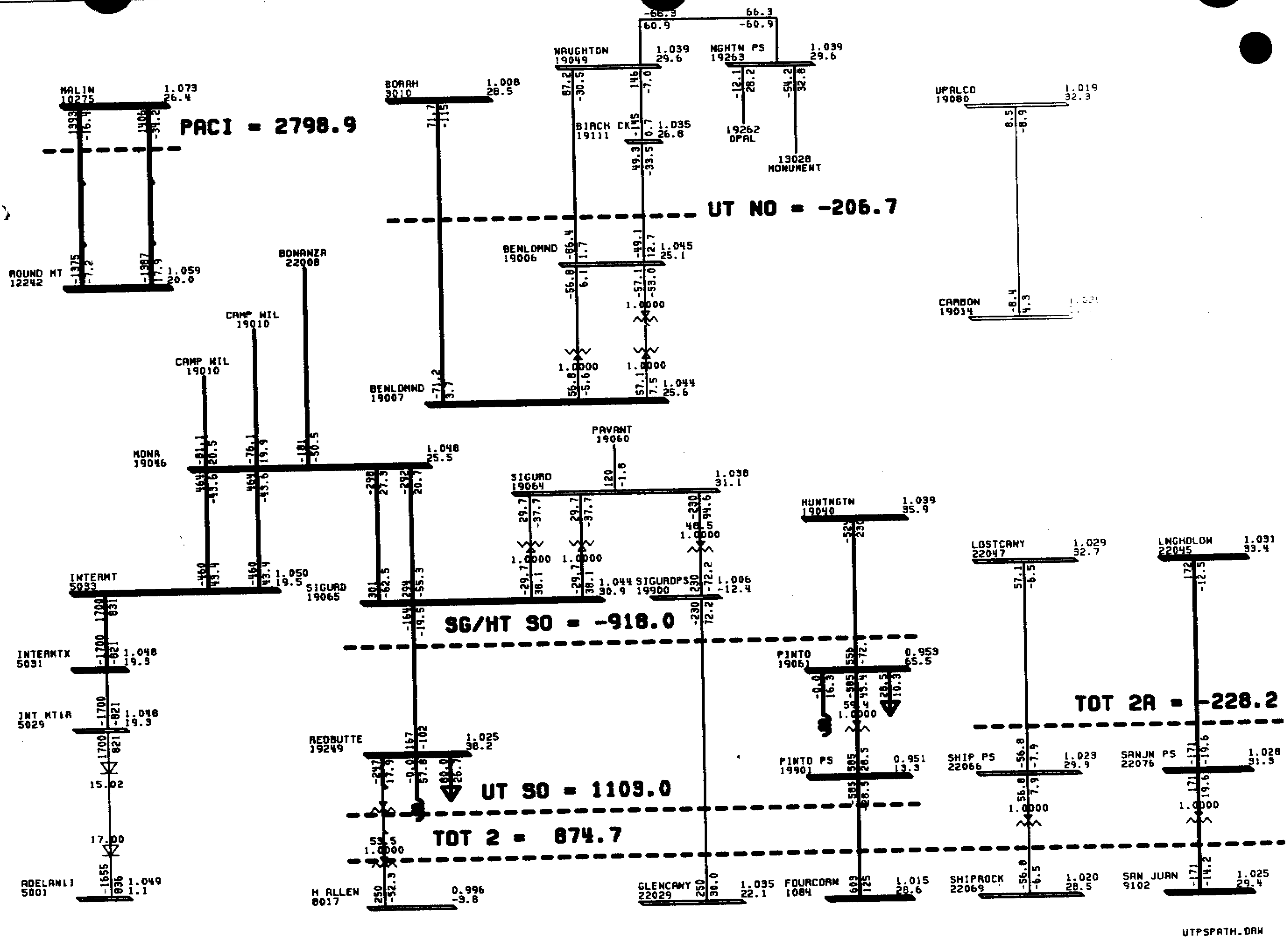
POINT D ON THE SOUTH TO NORTH NOMOGRAM IS DETERMINED BY THE STABILITY RESULTS OF CASE 4CNPNTO3 USING POWER FLOW CASE SONO3. THE UTAH SOUTHERN BOUNDARY FLOWS IN THIS POWER FLOW ARE: 250 MW FOR THE HARRY ALLEN-RED BUTTE 345 KV LINE, 603 MW ON THE FOUR CORNERS-PINTO 345 KV LINE, AND 250 MW ON THE GLEN CANYON-SIGURD 230 KV LINE. THIS POWER FLOW CASE IS DERIVED FROM THE WSCC 1990LS2 BASE CASE WHICH HAS BEEN MODIFIED TO ADD THE UTAH PHASE SHIFTING TRANSFORMERS AND TO CHANGE SCHEDULES TO ACHIEVE THE DESIRED LINE FLOWS. THE WORST SINGLE CONTINGENCY REPRESENTED IN STABILITY CASE 4CNPNTO3 IS THE LOSS OF THE FOUR CORNERS-PINTO 345 KV LINE.

THE STUDY RESULTS SHOW THAT FOR THIS DISTURBANCE, SYSTEM STABILITY IS MAINTAINED WHILE THE LOWEST FIRST-SWING VOLTAGE (.82 PER UNIT) OCCURS AT THE HARRY ALLEN 230 KV BUS. THE GLEN-CANYON RELAY IS ACCEPTABLE IN THIS CASE. PLOTS ARE ATTACHED WHICH SHOW THE STUDY RESULTS. THEREFORE, THE LINE FLOWS FOR POINT D ON THE SOUTH TO NORTH NOMOGRAM ARE:

FOUR CORNERS-PINTO = 600 MW

GLEN CANYON-SIGURD = 250 MW

BORDER-RED BUTTE = 250 MW



SONO3-M90LSP1-ADD NEV TIE, RMV CRG-BNZA 345 LN. UTAH
PS IN. HALN-RBUT=250, GLN-SIG=250, 4CRN-PNTO=600
FRI DEC 16, 1988 16:14

KV: ≤138 , ≤230 , ≤345

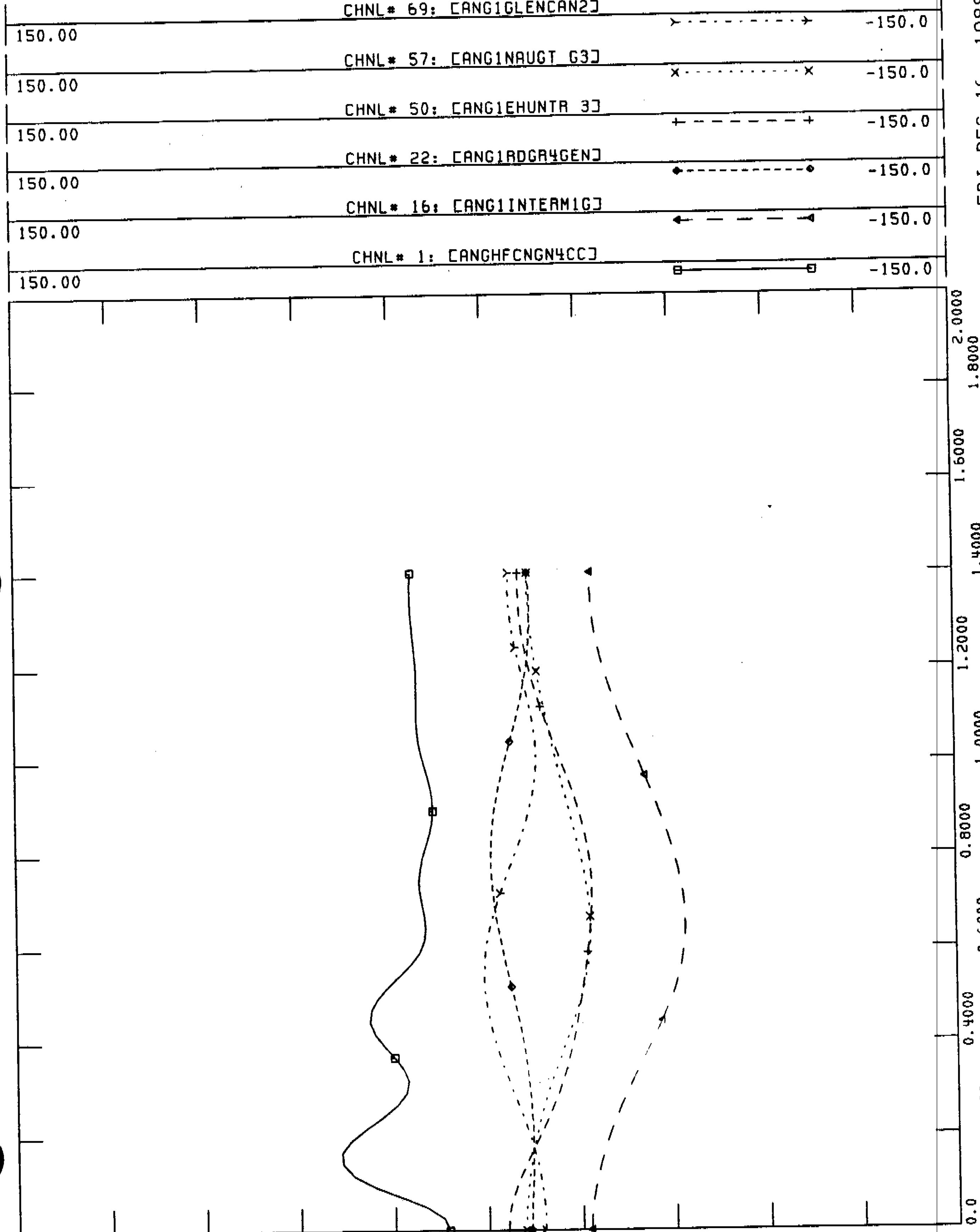
BUS - VOLTAGE (PU)/ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

SON03-M90LSP1-ADD NEV TIE, RMV CRG-BNZA 345 LN. UTAH
PS IN. HALN-RBUT=250, GLN-SIG=250, 4CRN-PNTO=600
3 PH FLT ON 4CRN-PNTO 345 LINE. RMV FLT/LINE @ 4 CY.

FRI DEC 16, 1988 15:52

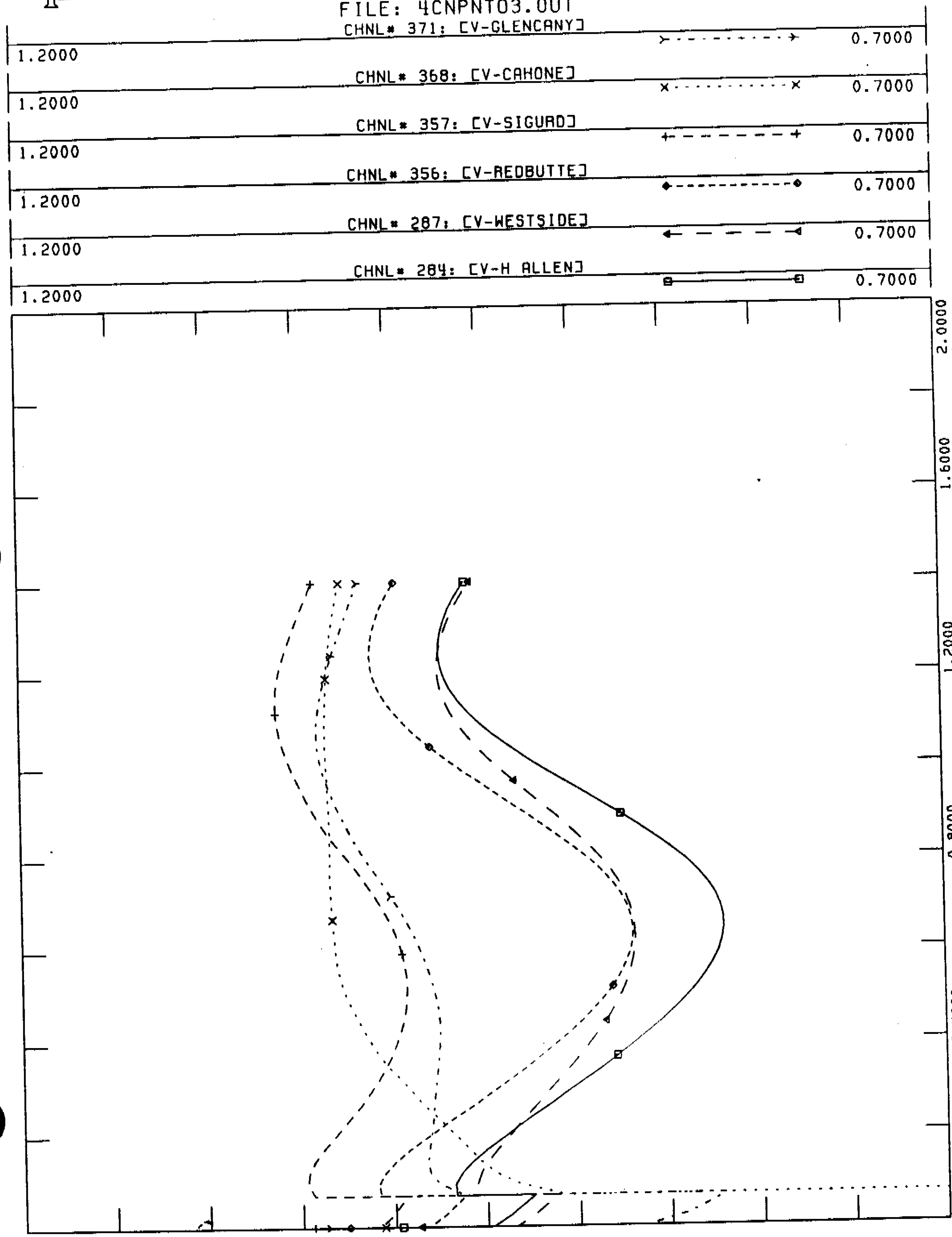
REL. ROTOR ANG.- PLOT 10

FILE: 4CNPNTO3.OUT



SONO3-M90LSP1-ADD NEV TIE, RMV CRG-BNZA 345 LN. UTAH
PS IN. HALN-RBUT=250, GLN-SIG=250, 4CRN-PNTO=600
3 PH FLT ON 4CRN-PNTO 345 LINE. RMV FLT/LINE @ 4 CY.

FILE: 4CNPNTO3.OUT



FRI DEC 16, 1988 15:53

BUS VOLTAGE - PLOT 11

SON03-M90LSP1-ADD NEV TIE, RMV CRG-BNZA 345 LN. UTAH
PS IN. HALN-RBUT=250, GLN-SIG=250, 4CRN-PNTO=600
3 PH FLT ON 4CRN-PNTO 345 LINE. RMV FLT/LINE @ 4 CY.

FRI DEC 16, 1988 15:55

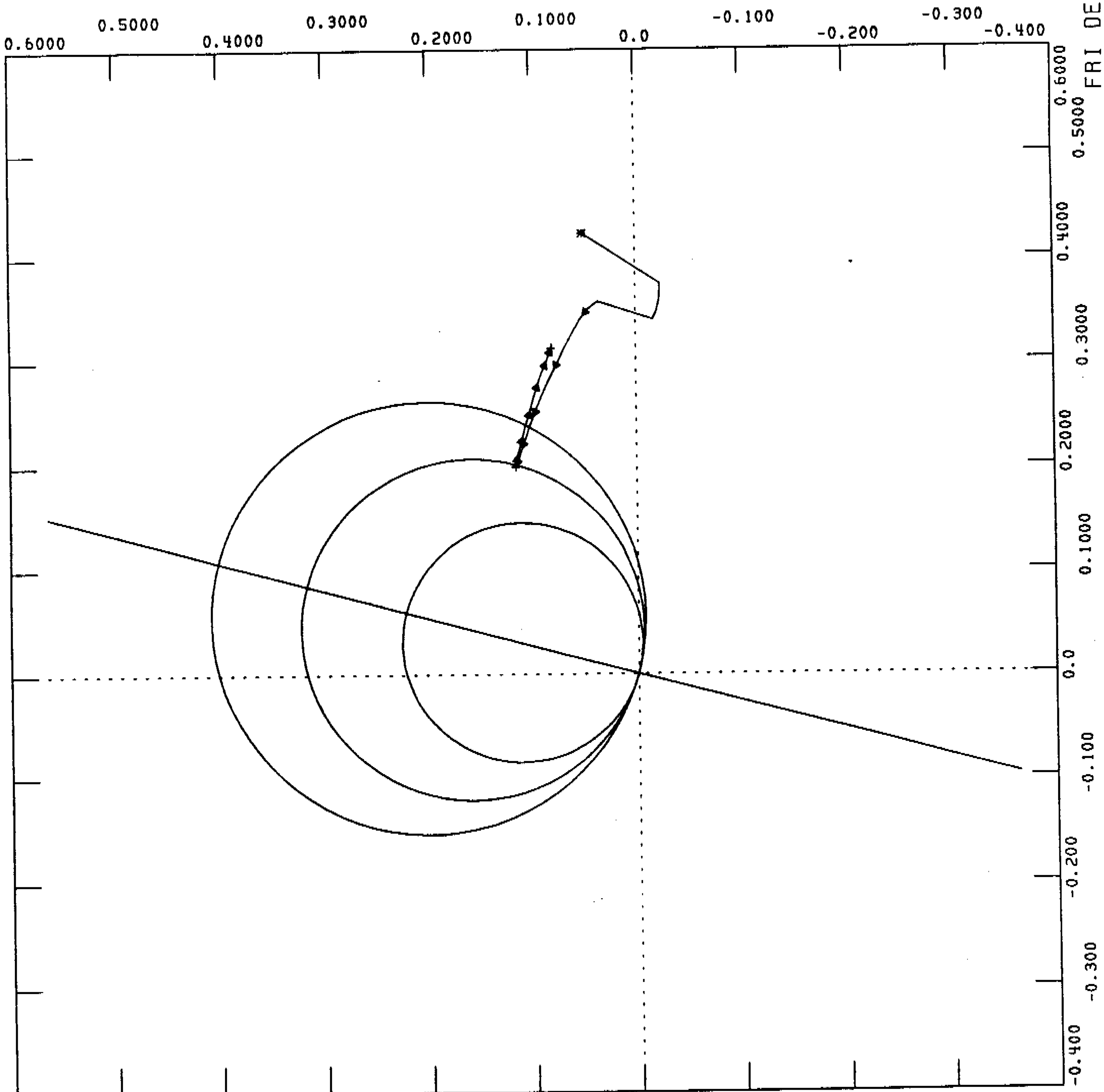
APPARENT IMP. - PLOT 12

FILE: 4CNPNTO3.OUT

RELAY: DISTR

TSTART: 0.0 TSTOP: 2.0 TIC INCREMENT: 0.1

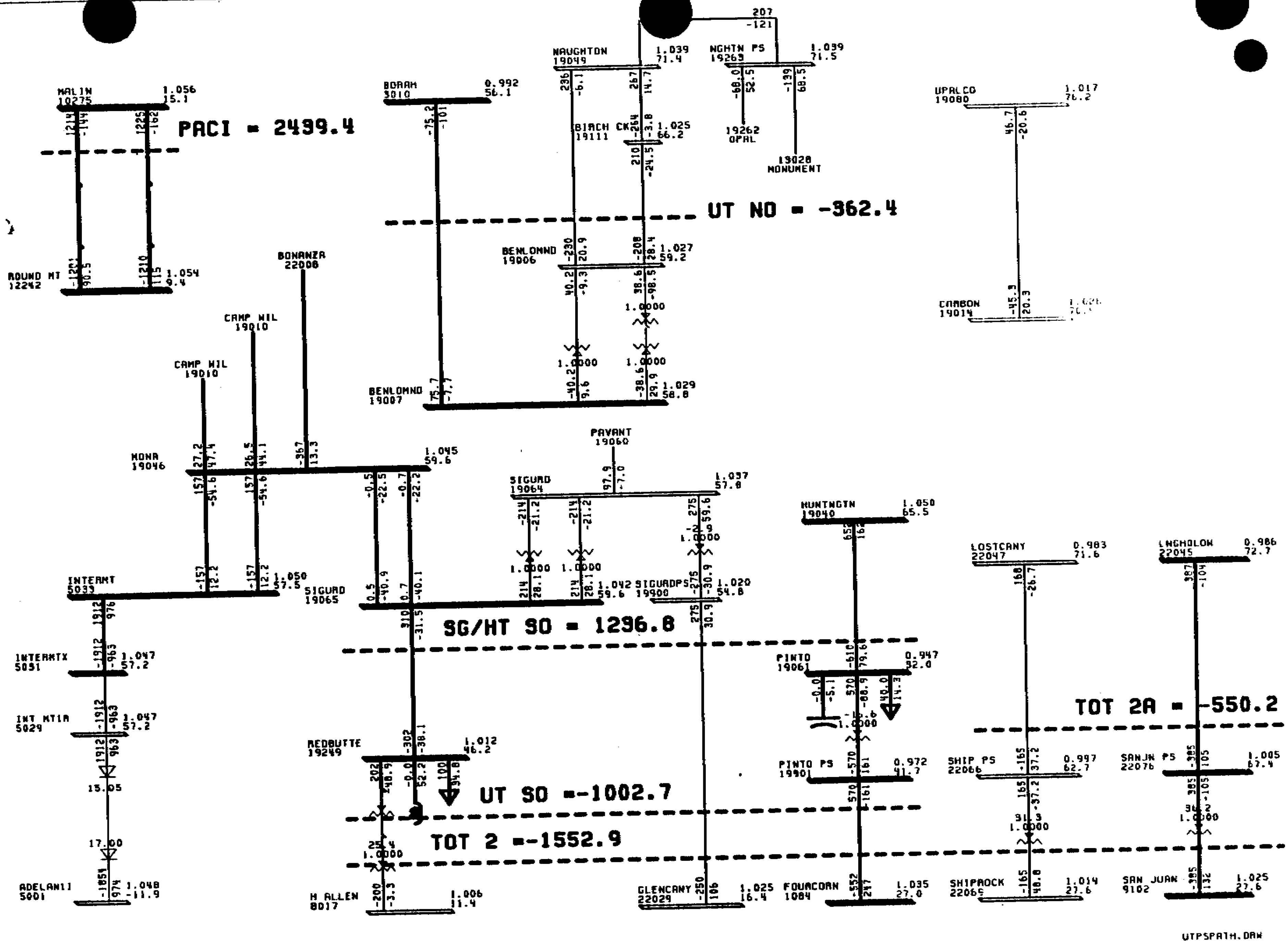
CHNL# 486: [XIGLEN-SIGPS]



PINTO-FOUR CORNERS
TRANSMISSION CAPACITY

PINTO - FOUR CORNERS TRANSMISSION CAPACITY

THE ESTC15 POWER FLOW CASE SHOWS THAT WITH THE 40 MW LOAD AT PINTO AND THE ADDITIONAL IMPEDANCE OF THE PINTO PHASE SHIFTING TRANSFORMERS, THE MINIMUM STEADY-STATE VOLTAGE CRITERIA (.95 PER UNIT) IS REACHED AT THE PINTO LOAD BUS. SINCE THE FLOW INTO FOUR CORNERS IS 552 MW, THE NEW LIMIT FOR THE PINTO-FOUR CORNERS TRANSMISSION CAPACITY IS 550 MW. THE POWER FLOW PLOT FOR CASE ESTC15 IS ATTACHED.



ESTC15-M90LS2-RMV CRG-BNZA 345 LN. ADD UTAH PS.
SIG-RBUT = 310MW. SIG-GLEN = 275MW. HNTG-PNTO = 650MW
THU DEC 15, 1988 14:33

KV: ≤138 , ≤230 , ≤345

BUS - VOLTAGE (PU) /ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

TRANSMISSION CAPACITY NORTH OF BEN LOMOND

TRANSMISSION CAPACITY

NORTH OF BEN LOMOND

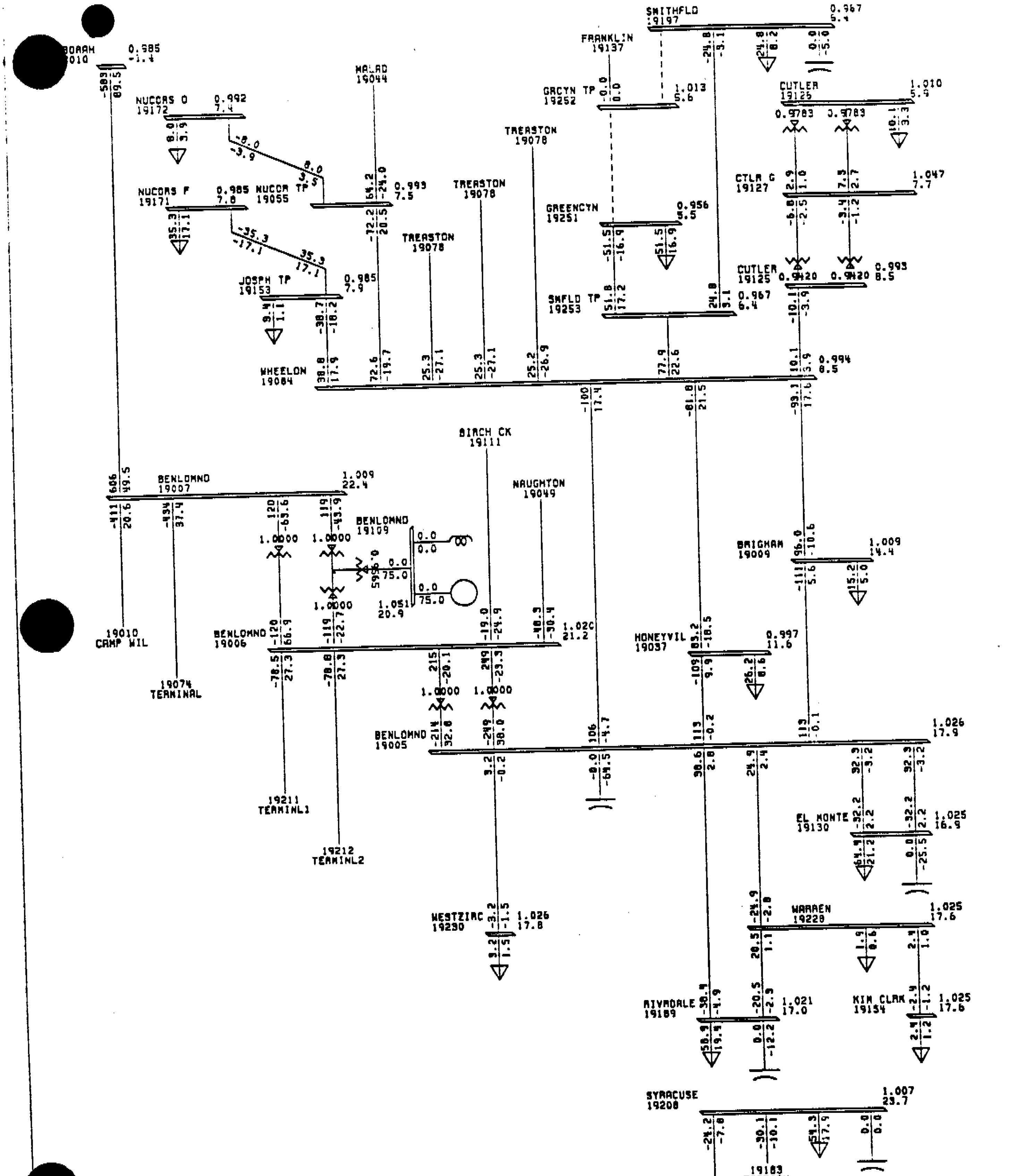
In order to determine the transmission constraint to the north of the Utah system, it is necessary to study two boundaries which can cause constraints to the north: 1) the lines north of Ben Lomond (see tablulation below), and 2) the lines further north which make up Path C. The difference between these two paths is the generation and load in the Northern Utah/Southeast Idaho area.

Power flow studies were run to determine which Path reached a constraint first. Study results show that the Path just north of Ben Lomond reached a constraint before Path C. The capacity limit for this Path was shown to be 1,190 MW. This limit is based on reaching the summer emergency thermal overload line rating on the three 138 kV lines going north out of Ben Lomond for loss of the Ben Lomond-Borah 345 kV line. When this Path is at its maximum of 1,190 MW, the sum of the line flows on Path C is approximately 800 MW. Therefore, the transmission capacity south-to-north on Path C is actually determined by the constraint north of Ben Lomond minus the net load in between Ben Lomond and the Borah/Goshen areas. The transmission capacity south-to-north, then, on Path C is 800 MW.

Power flow maps are attached for the two cases: 1) all lines in, and 2) Ben Lomond-Borah out of service. A summary of significant line flow is summarized below:

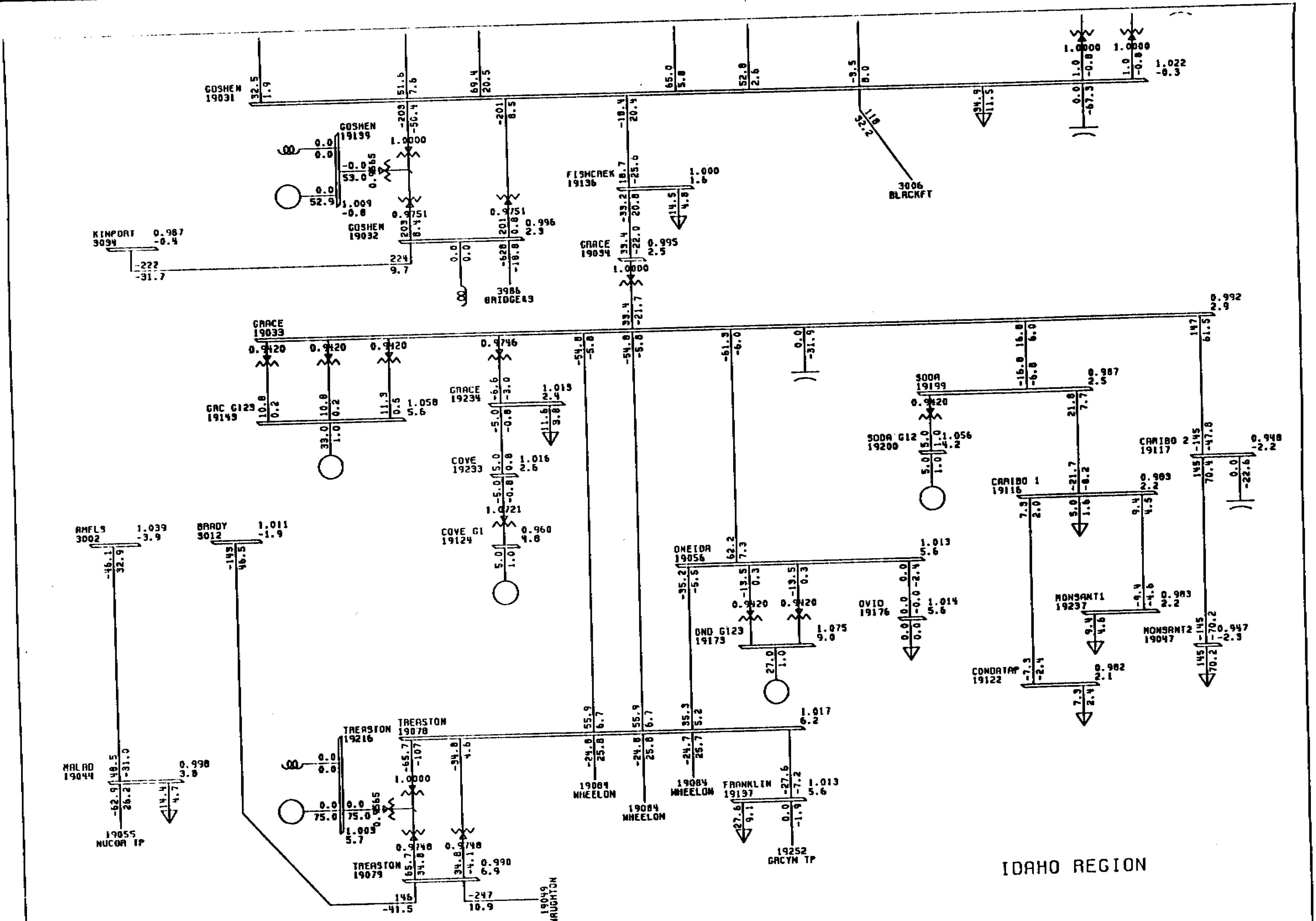
Lines North of Ben Lomond					Base Case (MW)	BL-Borah Outage (MW)	Summer Emer. Rating (MVA)
Ben Lomond	138	-	Brigham	138	113	168	164
Ben Lomond	138	-	Honeyvill	138	113	168	164
Ben Lomond	138	-	Wheelon	138	105	162	164
Naughton	230	-	Treasuret	230	255	321	
Ben Lomond	345	-	Borah	345	606	0	
Total					1,192	819	

Path C					Base Case (MW)	BL-Borah Outage (MW)
Goshen	161	-	Fishcreek	161	-18	-53
Brady	230	-	Treasuret	230	-143	-249
Am Falls	138	-	Malad	138	-46	-81
Borah	345	-	Ben Lomond	345	-583	0
Total					-790	-383



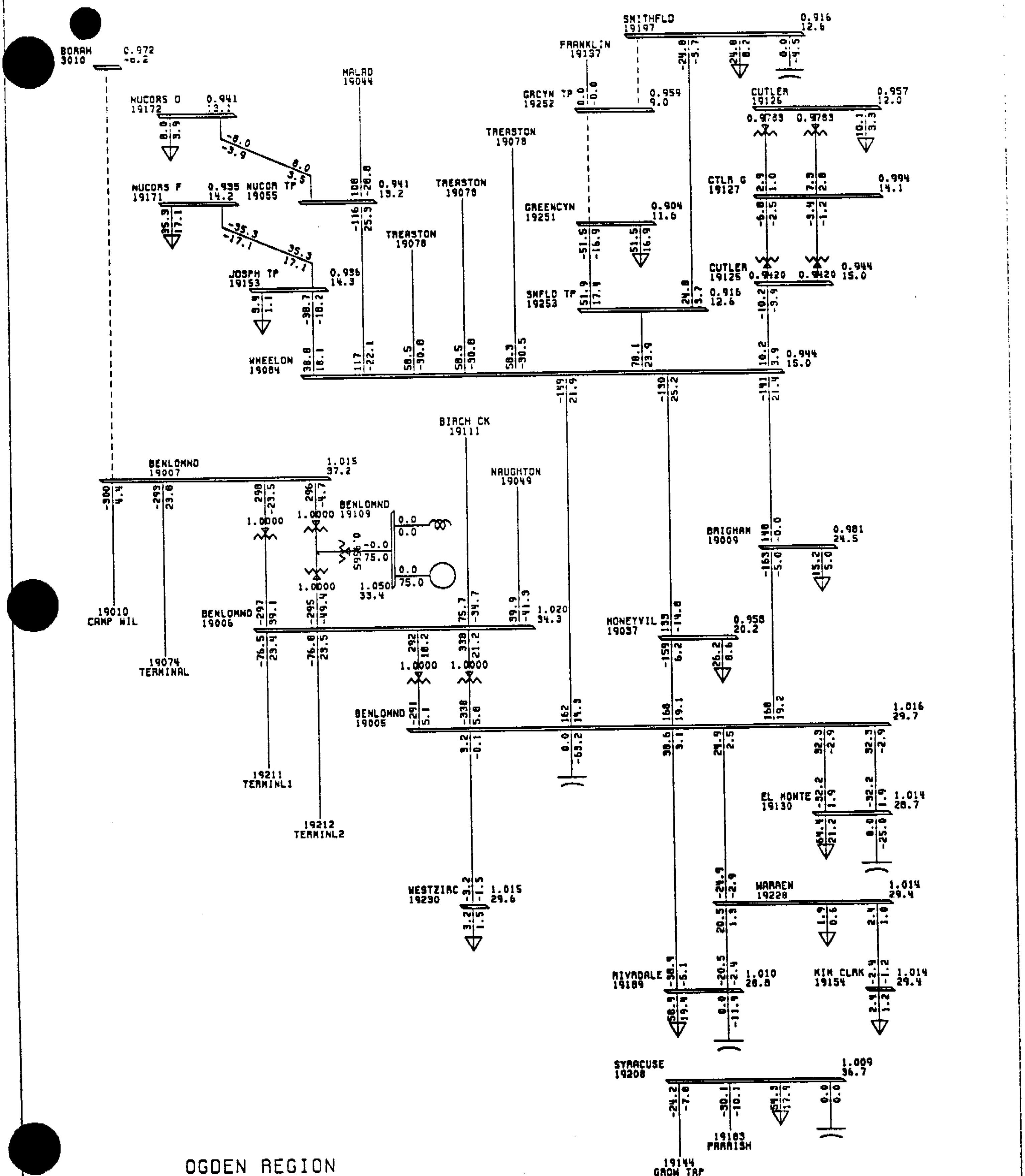
OGDEN REGION

TRANSMISSION CAPACITY NORTH OF BEN LOMOND STUDY
ALL LINES IN SERVICE - BASE CASE
TUE DEC 20, 1988 12:27

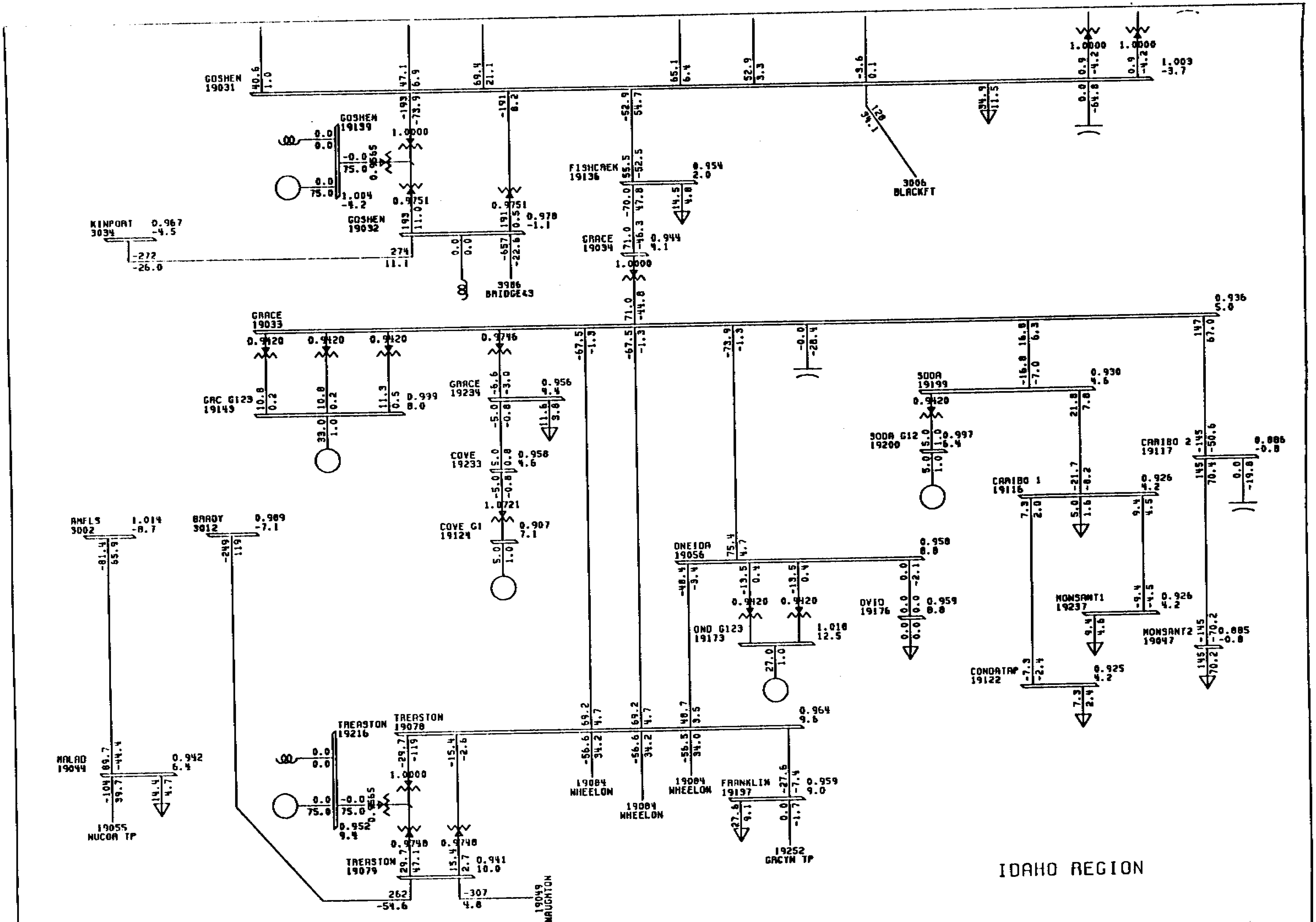


TRANSMISSION CAPACITY NORTH OF BEN LOMOND STUDY
LINES IN SERVICE - BASE CASE
DEC 20, 1988 12:28

BUS - VOLTAGE (PU) /ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR



TRANSMISSION CAPACITY NORTH OF BEN LOMOND STUDY
LOSS OF BEN LOMOND - BORAH 345 KV LINE
TUE DEC 20, 1988 12:29



TRANSMISSION CAPACITY NORTH OF BEN LOMOND STUDY
[?]S OF BEN LOMOND - BORAH 345 KV LINE
DEC 20, 1980 12:30

BUS - VOLTAGE (PU) /ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVA[R]

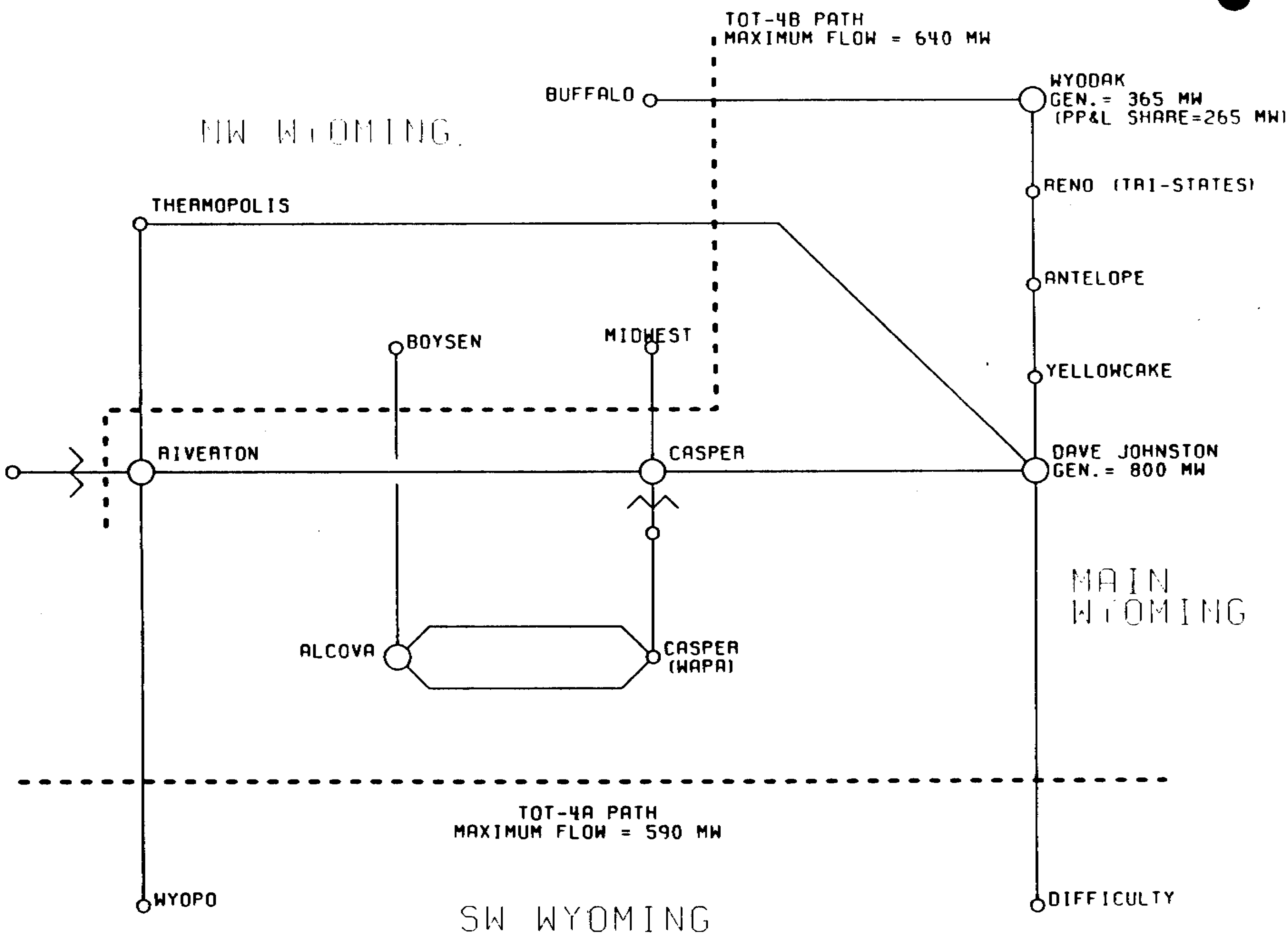
4A/4B NOMOGRAMS

4A/4B NOMOGRAMS

Path's M, N, and O are constrained by the 4A/4B nomogram. The following information and work papers help define and explain the 4A/4B path, the nomogram, proposed changes to configuration of a new line added to the 4A path. The WSCC Progress Report studies is also included showing the increased capability of 4A/4B.

A table - "Forecast Operating Points" is attached identifying load conditions and Wyoming generation surpluses used in the Path M, N, and O REC calculations.

PP&L WYOMING TRANSFER PATHS
(AS OF JAN., 1989)



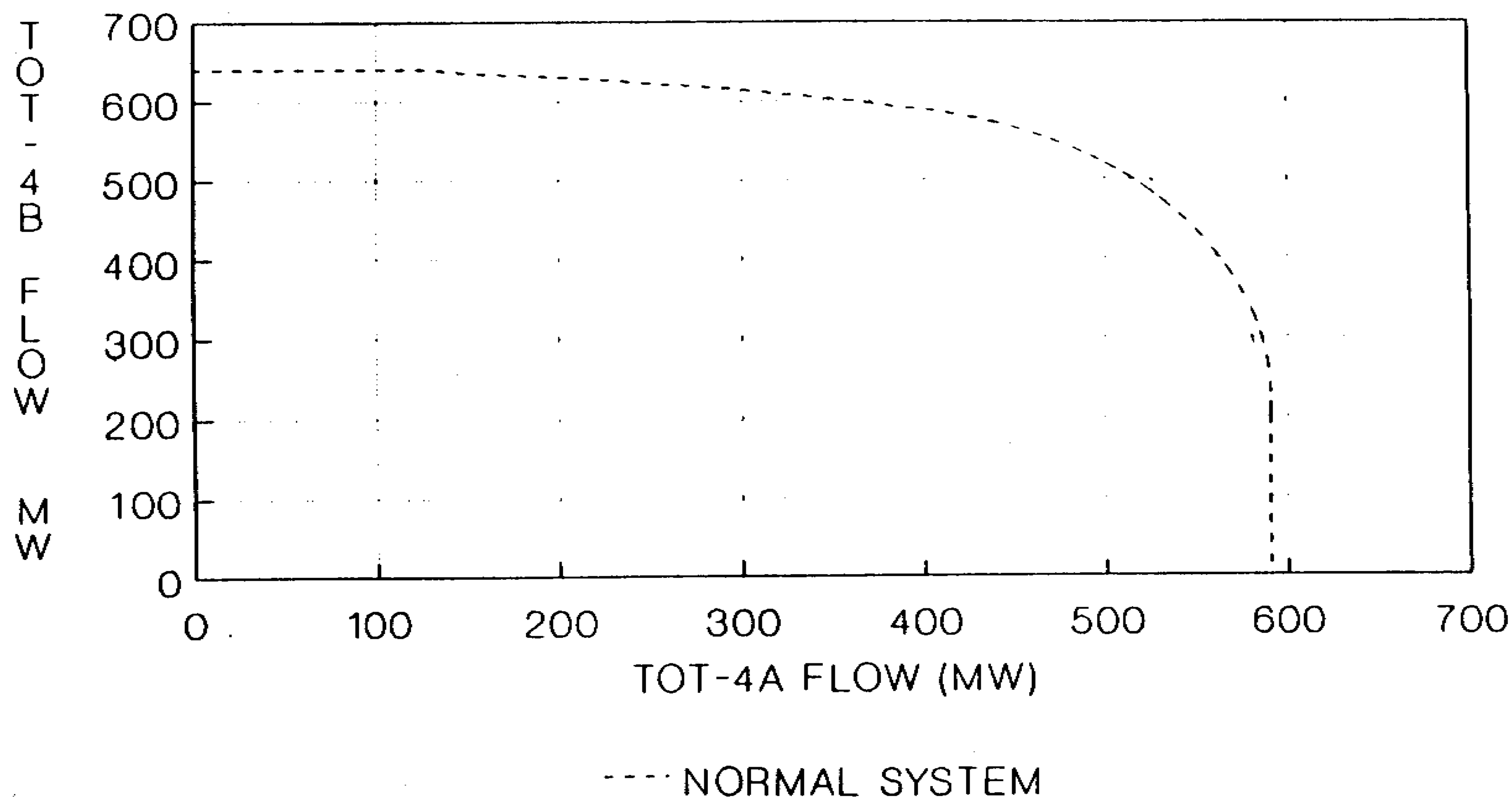
NOTE: LARGER CIRCLE INDICATES METERED POINT

11-23-88 DAJ

EXHIBIT

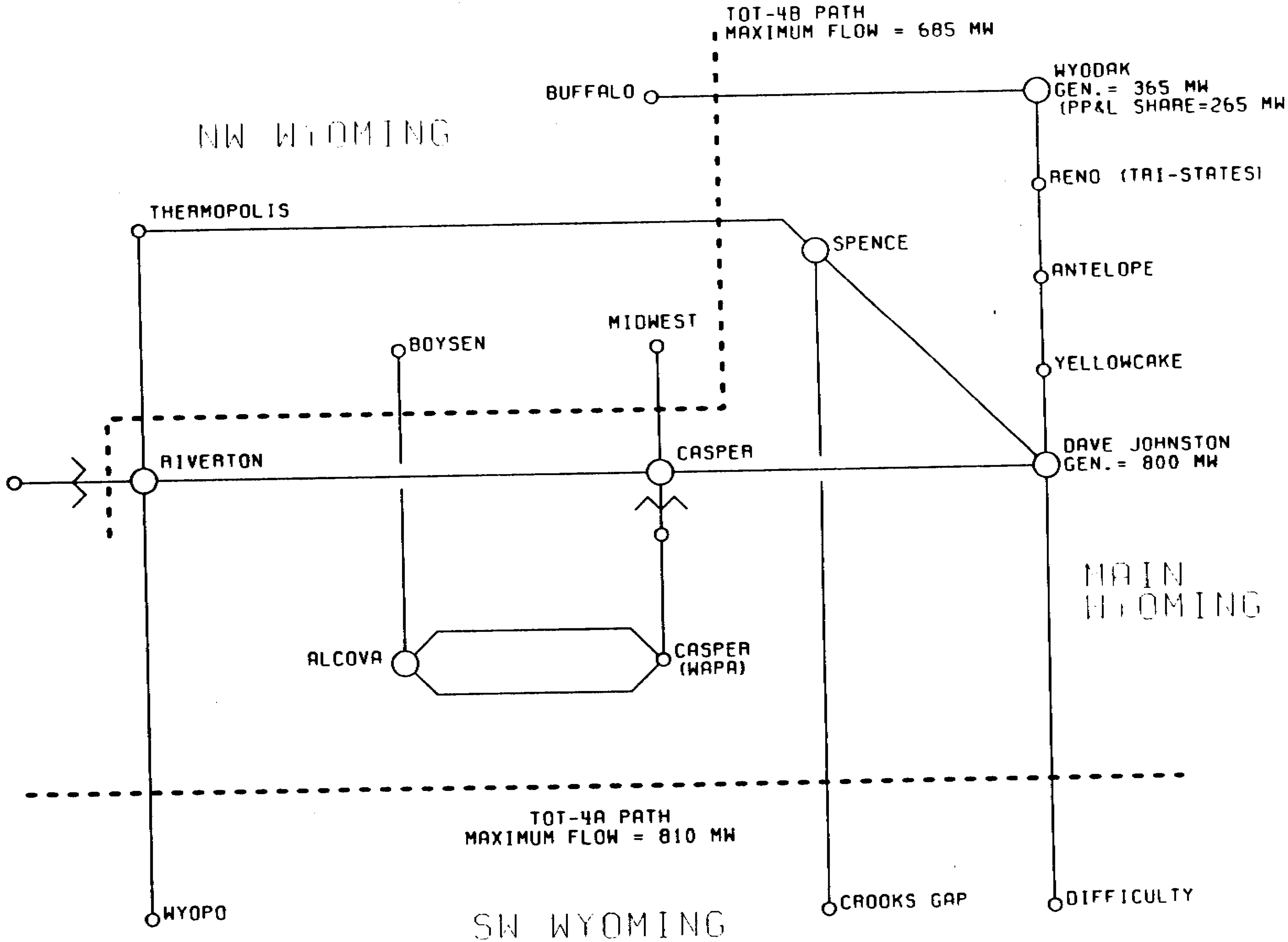
NOMOGRAM 4A/4B

1989-1991



W/DJ-THERMOPOLIS 230 KV
(JBA-12/16/88)

PP&L WYOMING TRANSFER PATHS
(AFTER DEC., 1990)



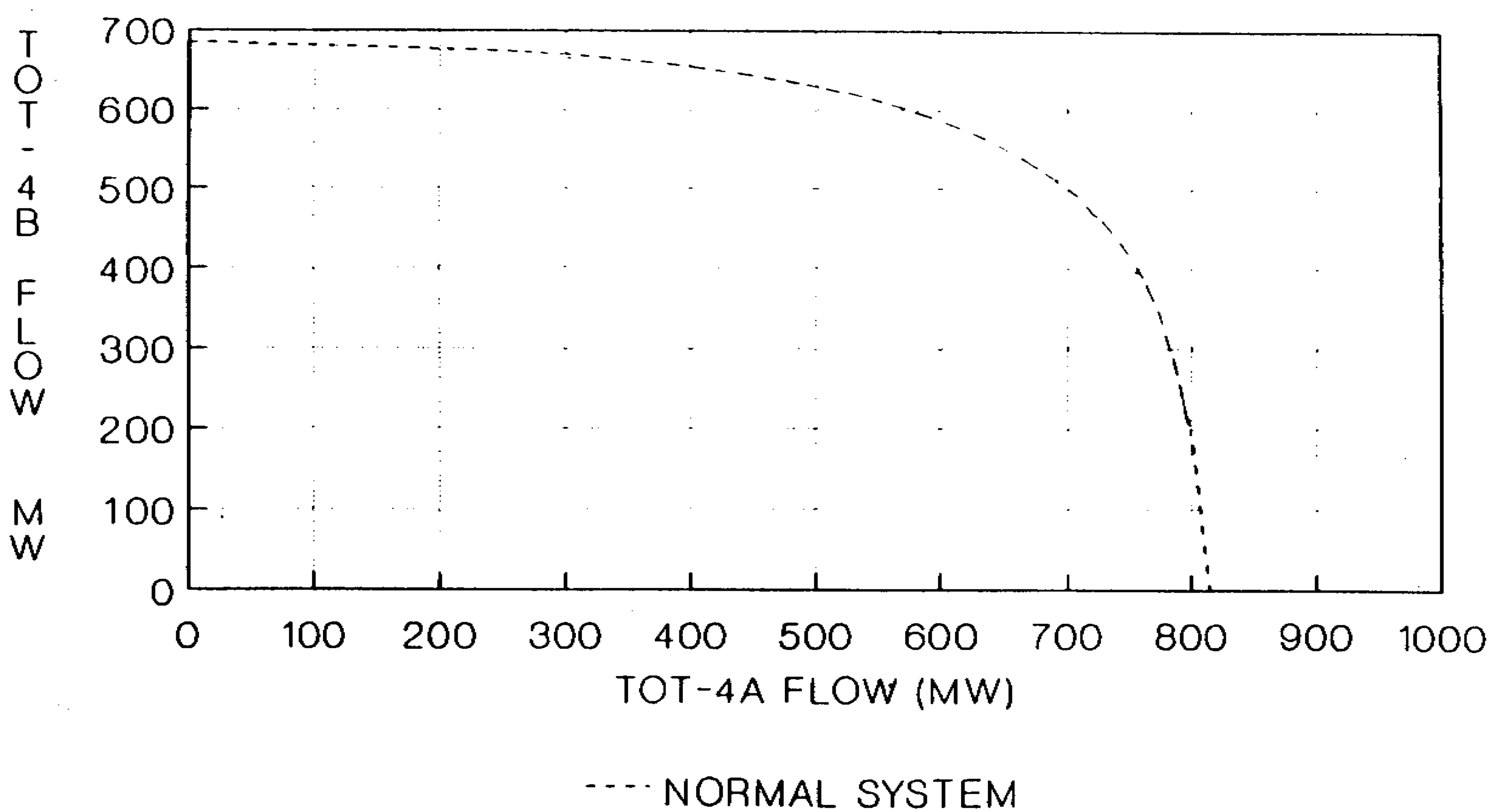
NOTE: LARGER CIRCLE INDICATES METERED POINT

11-23-88 DAJ

EXHIBIT

NOMOGRAM 4A/4B

1992-1993



W/JB-SPENCE 230 KV
(JBA-12/16/88)

SPENCE-JIM BRIDGER 230 KV PROJECT
WSCC PROGRESS REPORT

I. INTRODUCTION

The Spence-Jim Bridger 230 kV project consists of the construction of a 140-mile, single circuit, 230 kV AC line from WAPA's Spence substation to PP&L's Jim Bridger Substation. The Spence substation will be a new station located approximately 20 miles southeast of Casper, Wyoming on the Dave Johnston-Thermopolis 230 kV line. An intermediate 230/115 kV substation (Big Eagle) will tap the Spence-Jim Bridger 230 kV line near Bairoil, Wyoming to provide a new source to the Bairoil area.

The purpose of this project, planned for a December, 1990 operating date, is to provide additional capacity for load increases in the vicinity of Bairoil, improve system reliability by providing dual feed to Bairoil, and increase transmission capacity between Dave Johnston and Jim Bridger to offset potential adverse effects resulting from the operation of phase shifting transformers installed by WAPA in southern Colorado.

II. IMPACT ON WSCC SYSTEM

Results of planning studies demonstrate the Spence-Jim Bridger 230 kV project will comply with the WSCC Reliability Criteria for System Design. No remedial action is required for the loss of this line, or any other lines in the vicinity. All post-fault voltages are above 71 % for all PP&L Area buses, and 78 % for all Others' Area buses. All bus frequencies are above 59.75 Hz..

III. PROJECT STUDIES

All studies were conducted using a modified WSCC power flow case (1988-89 LW2) to simulate conditions before and after the installation of Spence-Jim Bridger 230 kV Project. The following changes were made:

A. Existing System Case

- Modification of the transmission system to reflect changes to the 115 kV system between Dave Johnston and Casper, and the addition of the Dave Johnston-Thermopolis 230 kV line.

- Adjustments of schedules to achieve approximately 600 MW of flow across boundary path Tot-4A.

B. System with the Spence-Jim Bridger 230 kV Project

- Modification of the transmission system to reflect changes associated with the Spence-Jim Bridger 230 kV line, and the Big Eagle 230/115 kV substation.

- Adjustments of schedules to achieve approximately 800 MW of flow across boundary path Tot-4A.

Results of the power flow and stability studies run indicate that the limiting condition for the Wyoming system is a loss of the Dave Johnston-Difficulty 230 kV line. For an outage of the DJ-Difficulty 230 kV line, the limiting system constraint is maintaining 0.900 p.u. bus voltage after the line has opened and prior to system changes (i.e. a power flow limitation). The transfer capability of boundary path Tot-4A is shown to increase from approximately 600 MW to approximately 815 MW for the addition of the Spence-Jim Bridger 230 kV line.

POWER FLOW CASES

88/89LW2-4A-004 (Base Case)	This power flow case represents the Wyoming system just prior to the addition of the Spence-Jim Bridger 230 kV Project. (Tot-4A flow = 606 MW)
88/89LW2-4A-004A (Outage Case)	This case, run from 004, represents an outage of the Dave Johnston-Difficulty 230 kV line (worst single line outage). The lowest voltage is 0.897 p.u. at the Atlantic City 230 kV bus.
88/89LW2-4A-007 (Base Case)	This case, run from 004, adds the Spence-Jim Bridger 230 kV Project. Schedules were adjusted to stress boundary path Tot-4A. (Tot-4A flow = 815 MW)
88/89LW2-4A-007A (Outage Case)	This case, run from 007, represents an outage of the Dave Johnston-Difficulty 230 kV line (worst single line outage). The lowest voltage is 0.901 at the Big Eagle 230 kV bus.

STABILITY CASES

Case: 88/89LW2-4A-004A

Description: A three-phase fault at the Dave Johnston 230 kV bus, followed by the loss of the Dave Johnston-Difficulty 230 kV line. This case is stable and well damped. This single line loss has no unacceptable effect on the WSCC system. This case achieves WSCC Reliability Criteria for System Design Level 'A' performance.

Results:

Minimum PP&L Area Voltage: 0.745 p.u. (Wyopo 230 kV bus)

Min. Others' Area Voltage: 0.780 p.u. (Riverton 115 kV bus)

Minimum System Frequency: 59.75 Hz. (DJ Unit #1 bus)

Case: 88/89LW2-4A-007A

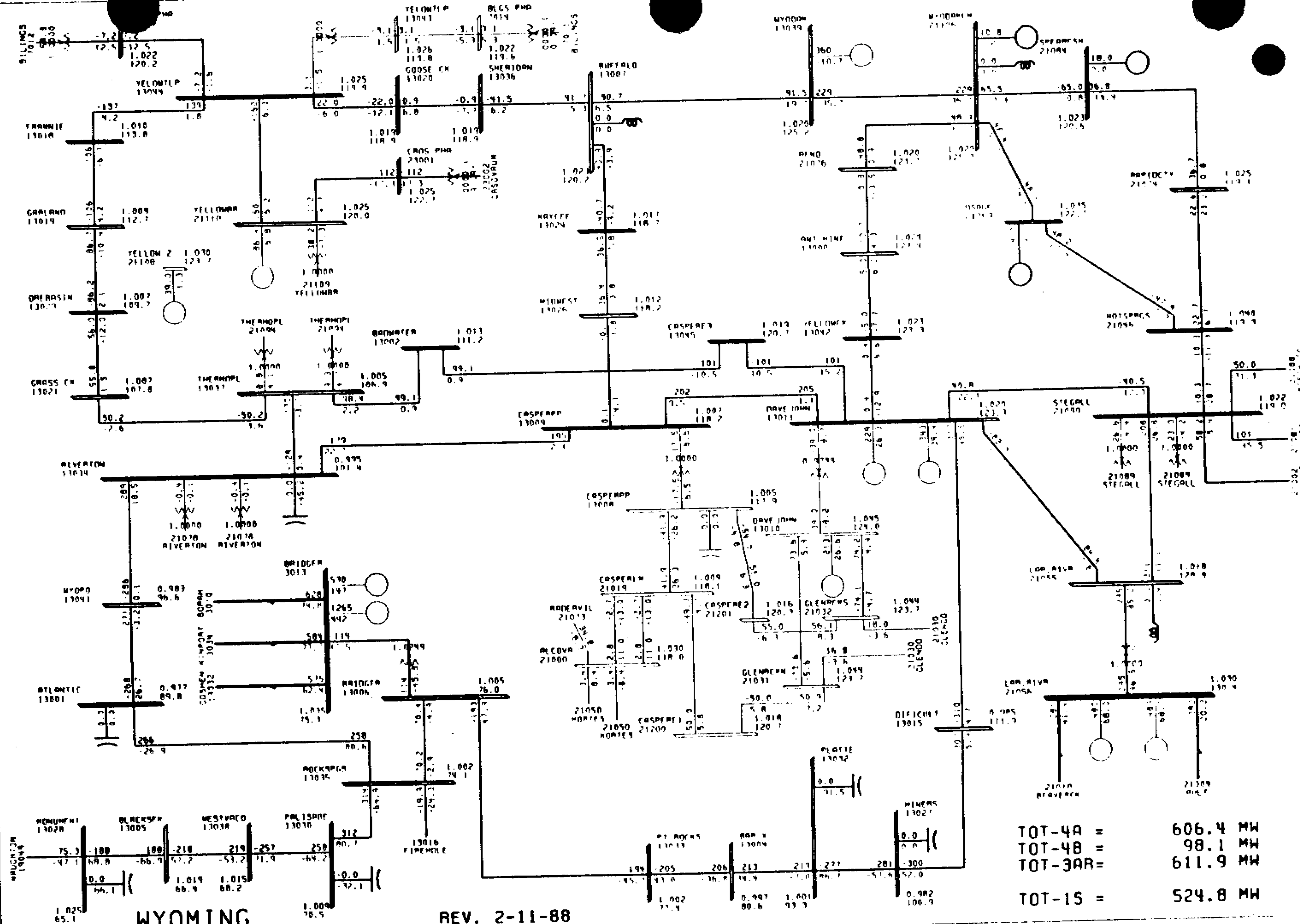
Description: A three-phase fault at the Dave Johnston 230 kV bus, followed by the loss of the Dave Johnston-Difficulty 230 kV line. This case is stable and well damped. This single line loss has no unacceptable effect on the WSCC system. This case demonstrates that this case achieves WSCC Reliability Criteria for System Design Level 'A' performance.

Results:

Minimum PP&L Area Voltage: 0.710 p.u. (Spence 230 kV bus)

Min. Others' Area Voltage: 0.778 p.u. (Riverton 115 kV bus)

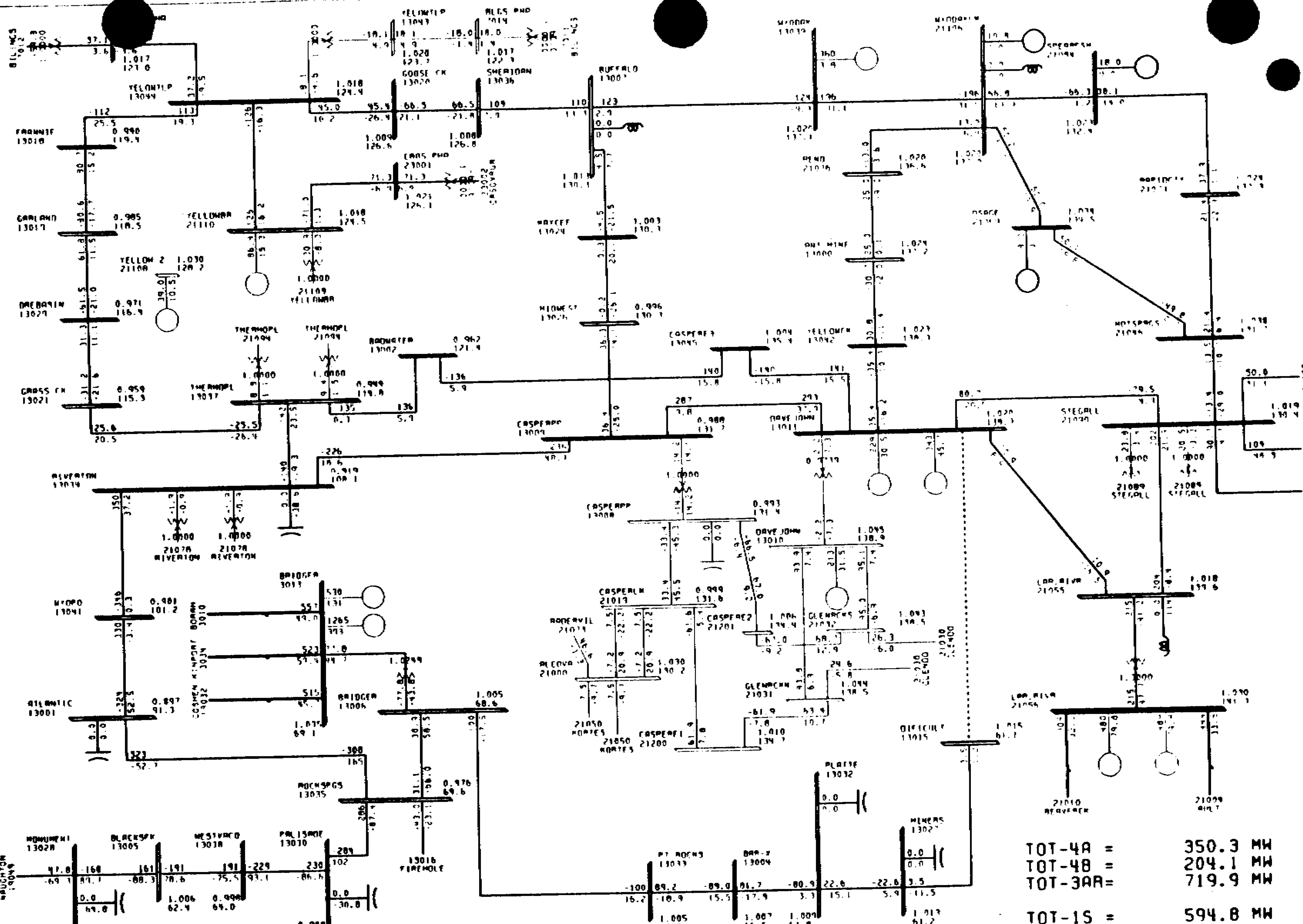
Minimum System Frequency: 59.75 Hz. (DJ Unit #1 bus)



88/89LW2-4A-004 EXISTING PP&L SYSTEM AS OF 12-31-88 DAJ
FROM 88/89LW2-4A-003: ADD DJ-THRMPL 230KV PROJECT CHANGES
TRANSMISSION SYSTEM PLOT MON, AUG 22 1988 15:41

0.950UV 1.050OV
KV: ≤161 ,≤230 ,≤345

BUS - VOLTAGE(PU) ANGLE
BRANCH - MW MVAR
EQUIPMENT - MW MVAR



TOT-4A = 350.3 MW
TOT-4B = 204.1 MW
TOT-3AA= 719.9 MW

TOT-1S = 594.8 MW

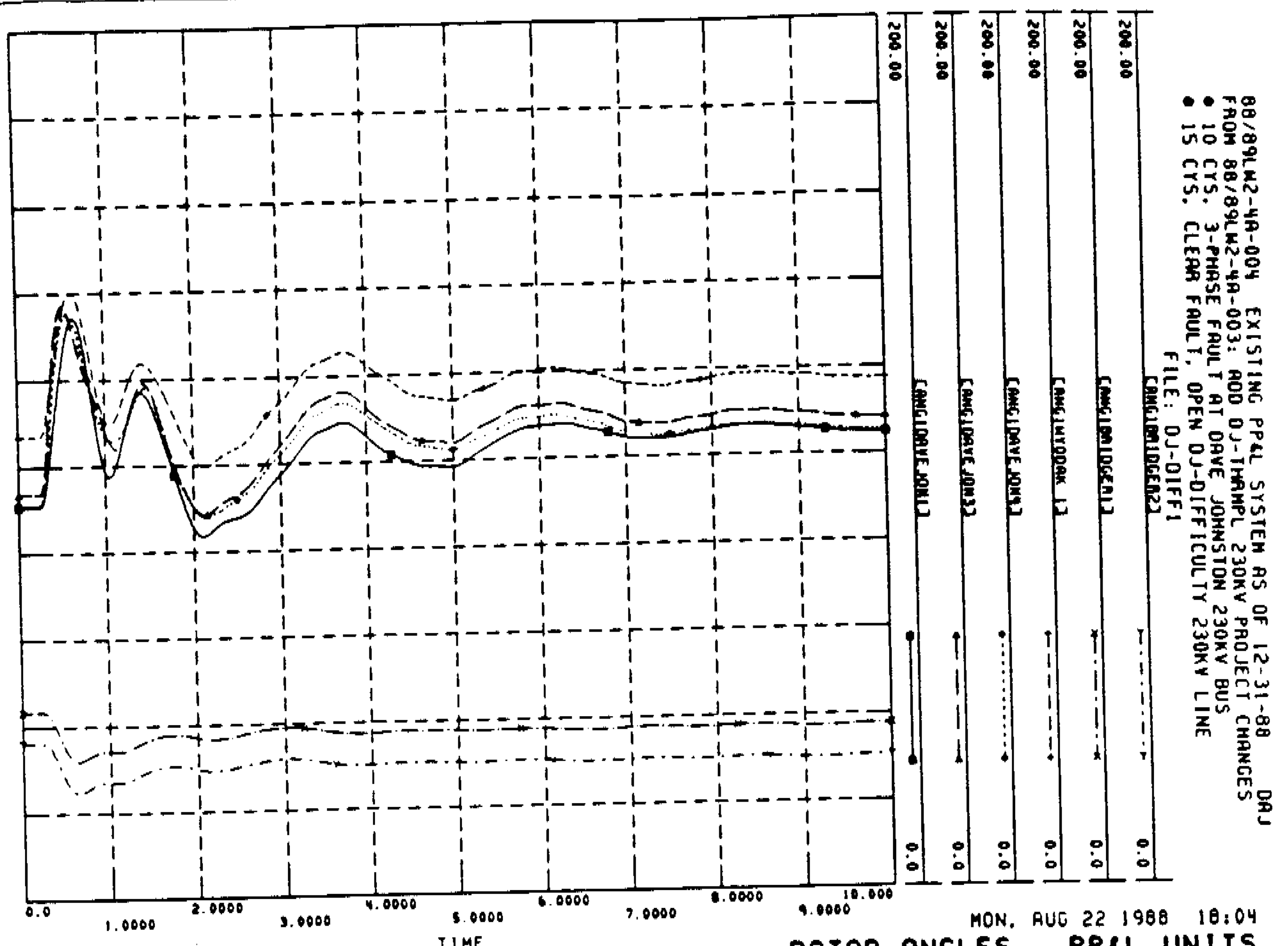
WYOMING

REV. 2-11-88

88/89LW2-4A-004A EXISTING PP&L SYSTEM AS OF 12031-88 DAJ
FROM 88/89LW2-4A-004 : OUTAGE OF DJ-DIFFICULTY 230KV LINE
TRANSMISSION SYSTEM PLOT MON. AUG 22 1988 15:49

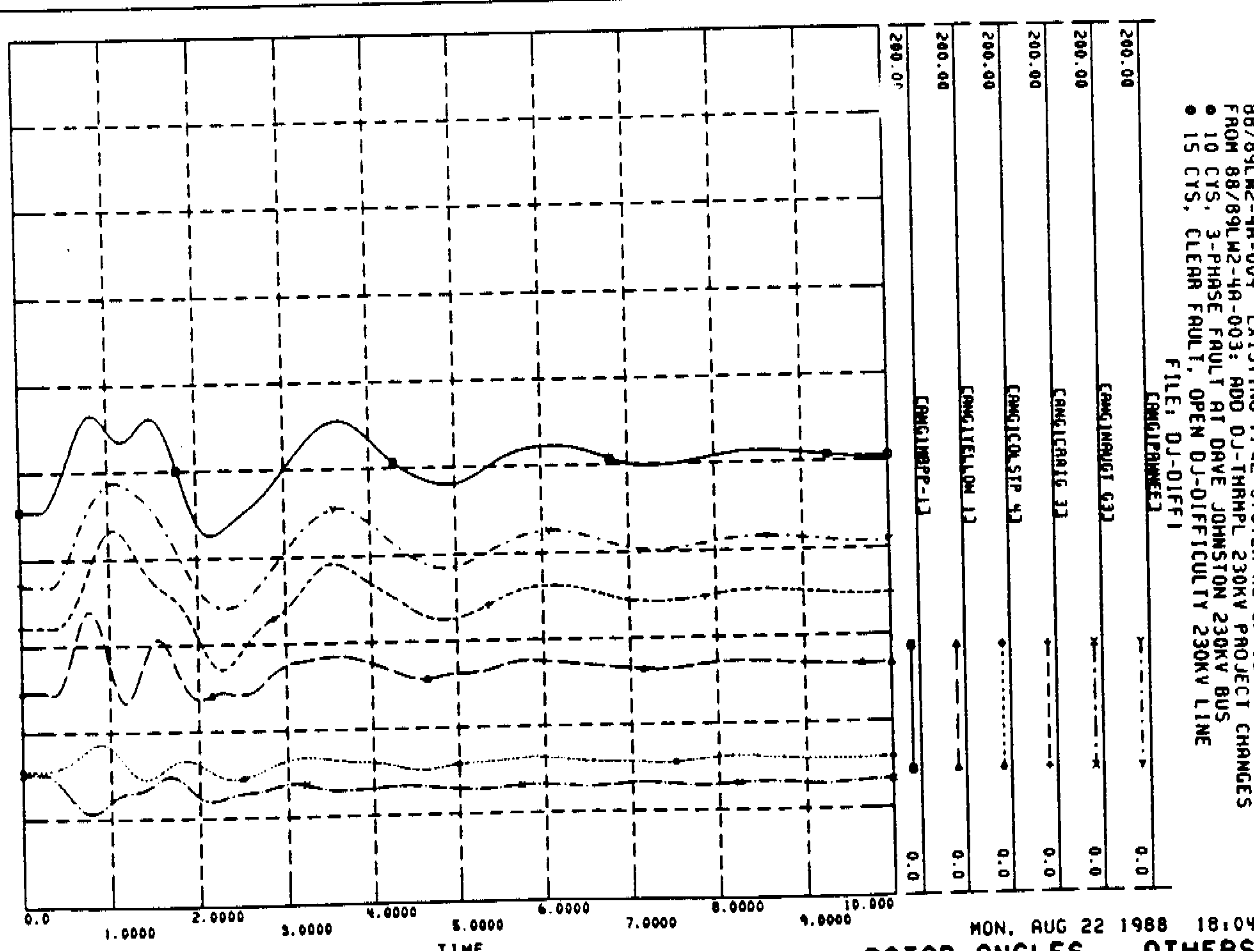
KV: ≤161 , ≤230 , ≤345

BUS - VOLTAGE/ANGLE
BRANCH - MW MVAR
EQUIPMENT - MW MVAR



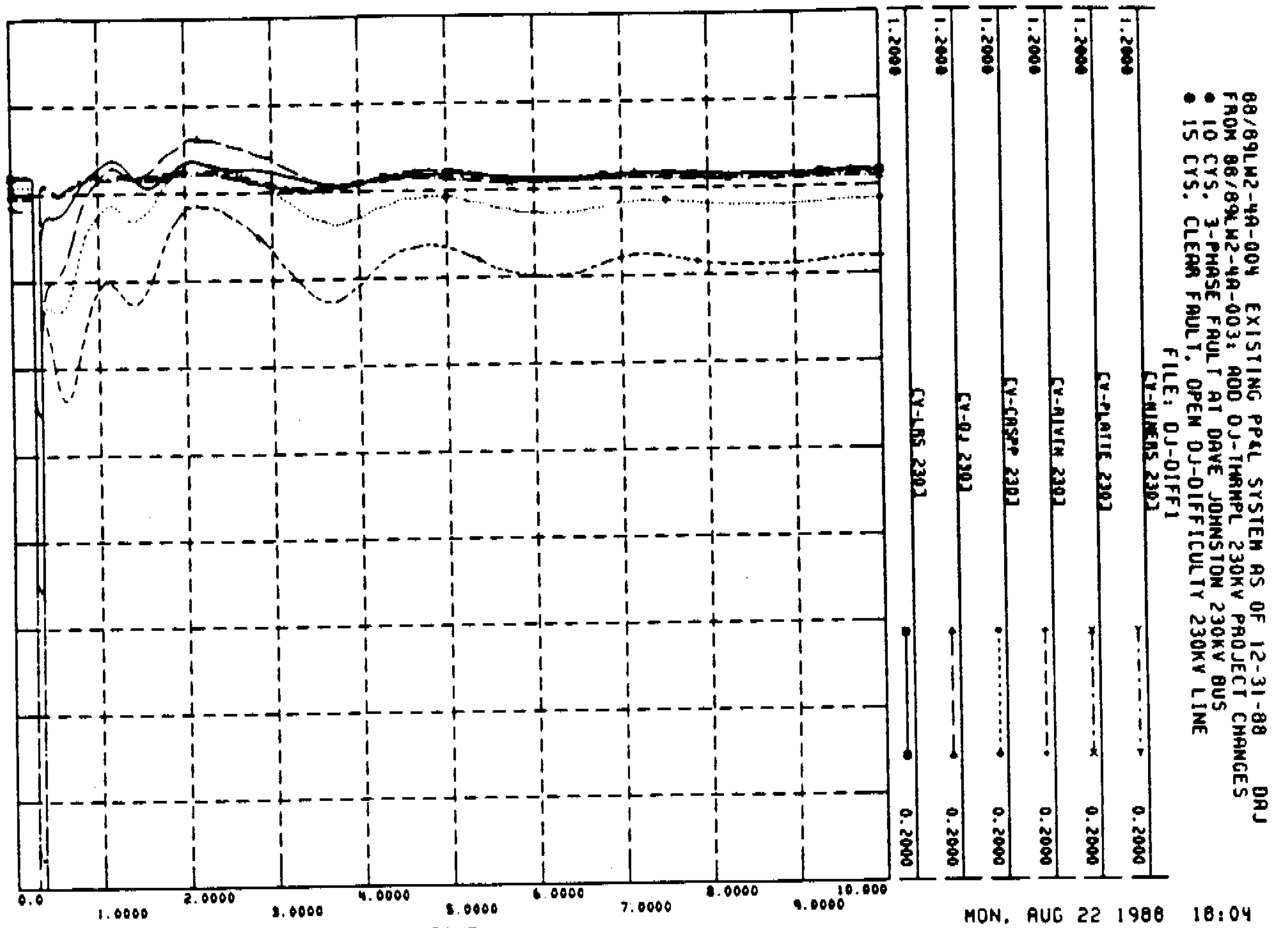
MON, AUG 22 1988 18:04

ROTOR ANGLES - PP&L UNITS

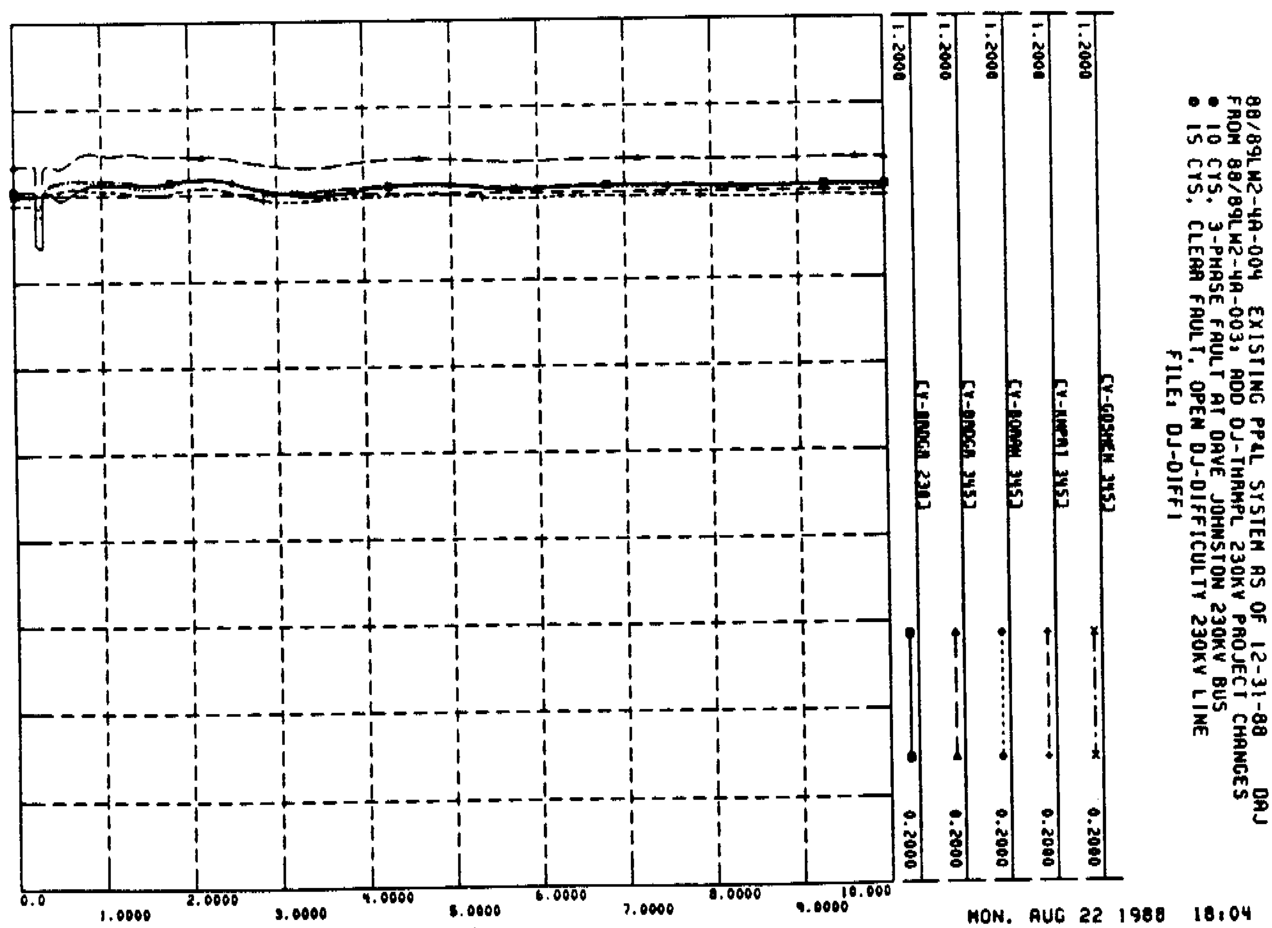


MON, AUG 22 1988 18:04

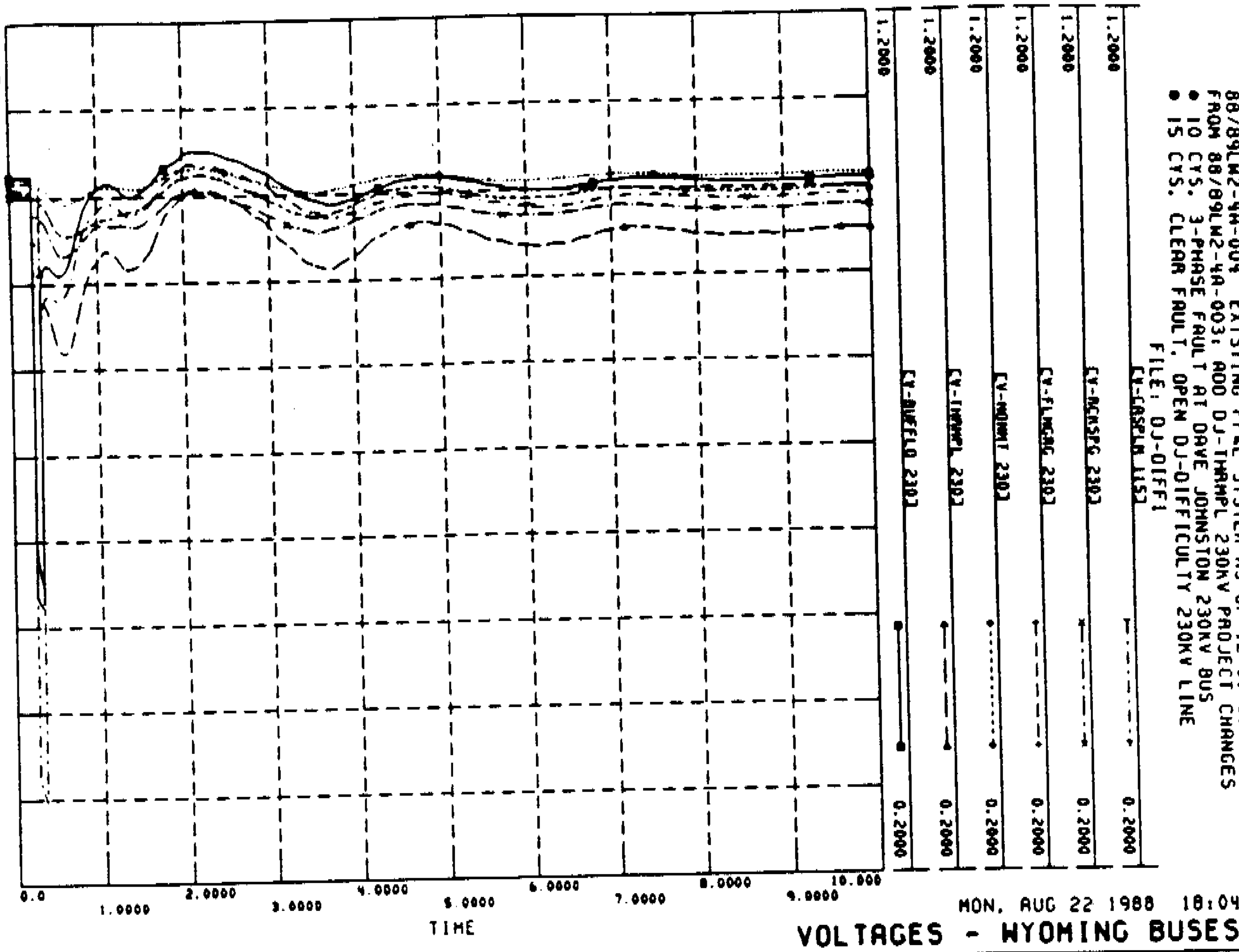
ROTOR ANGLES - OTHERS



VOLTAGES - PP&L BUSES

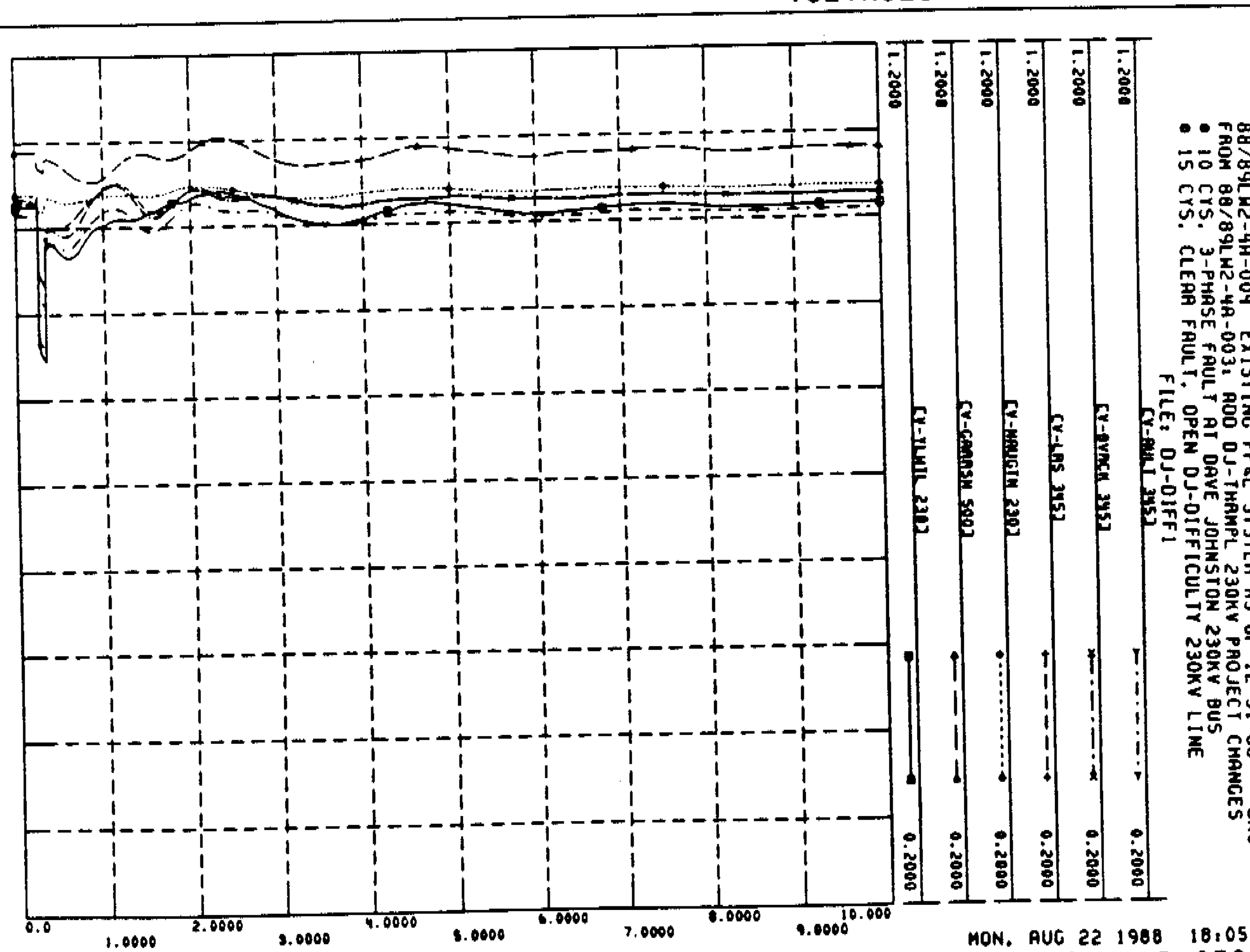


VOLTAGES - JB SYSTEM



MON, AUG 22 1988 18:04

VOLTAGES - WYOMING BUSES



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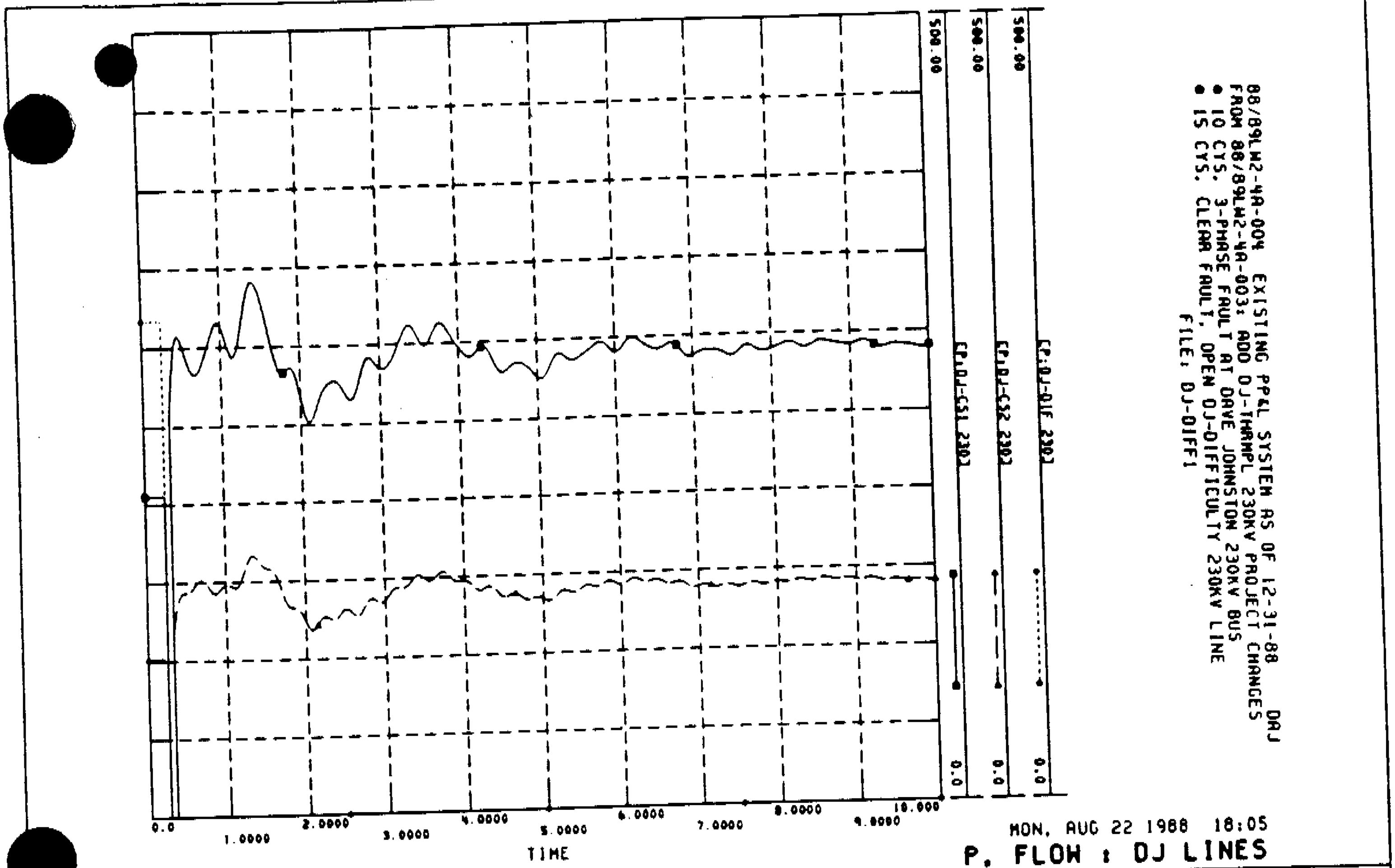
VOLTAGES - BOUNDARY BUSES


88/89LW2-4A-004 EXISTING PP&L SYSTEM AS OF 12-31-88 DAJ
FROM 88/89LW2-4A-003: ADD DJ-THRMPL 230KV PROJECT CHANGES
• 10 CYS. 3-PHASE FAULT AT DAVE JOHNSTON 230KV BUS
• 15 CYS. CLEAR FAULT, OPEN DJ-DIFFICULTY 230KV LINE
FILE: DJ-DIFF1
[P:DJ-DIF 230]
[P:DJ-CS2 230]
[P:DJ-CS1 230]
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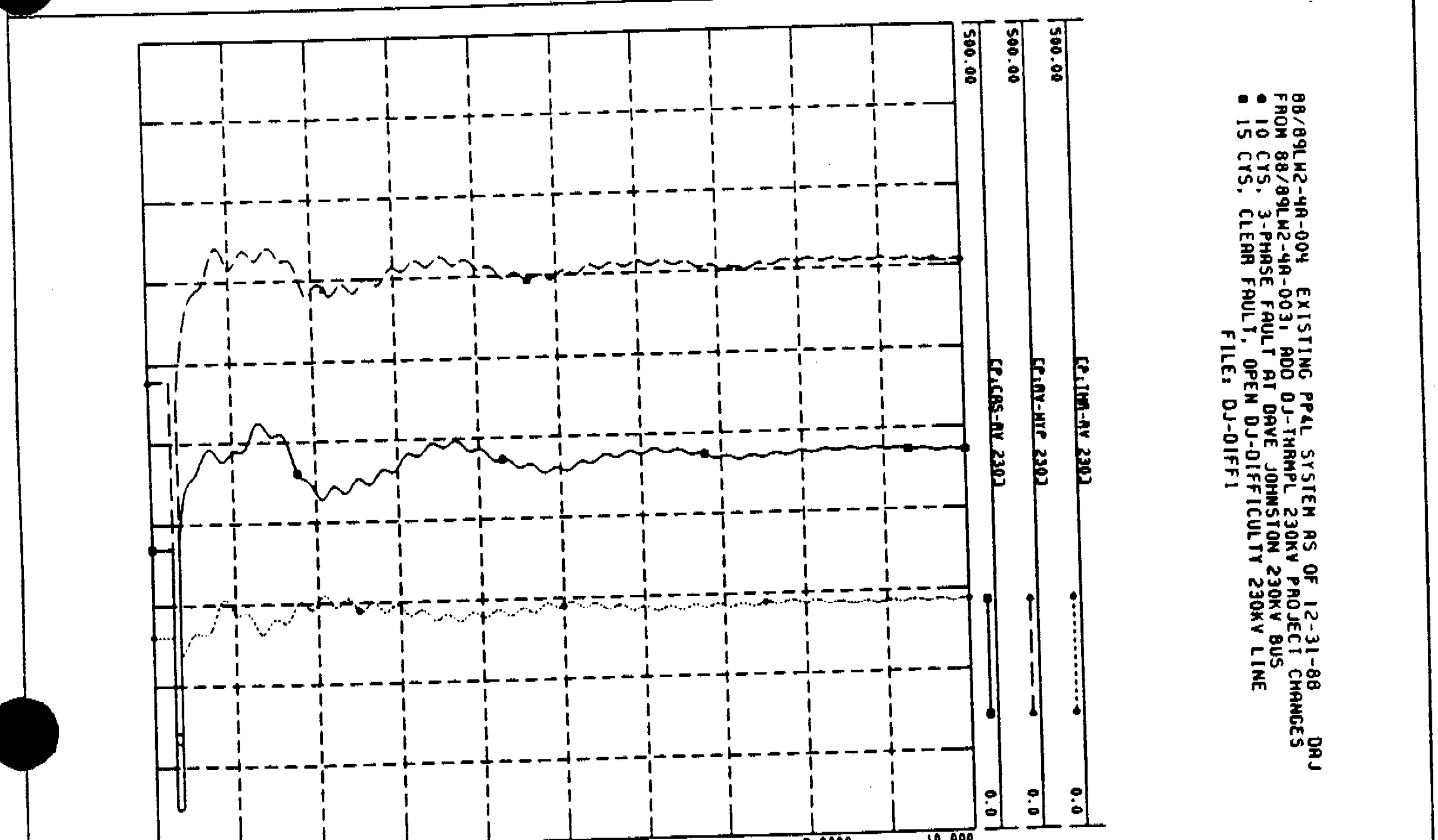
P. FLOW : DJ LINES


88/89LW2-4A-004 EXISTING PP&L SYSTEM AS OF 12-31-88 DAJ
FROM 88/89LW2-4A-003: ADD DJ-THRMPL 230KV PROJECT CHANGES
• 10 CYS. 3-PHASE FAULT AT DAVE JOHNSTON 230KV BUS
• 15 CYS. CLEAR FAULT, OPEN DJ-DIFFICULTY 230KV LINE
FILE: DJ-DIFF1
[P:THA-AY 230]
[P:AY-HYP 230]
[P:CAS-AY 230]
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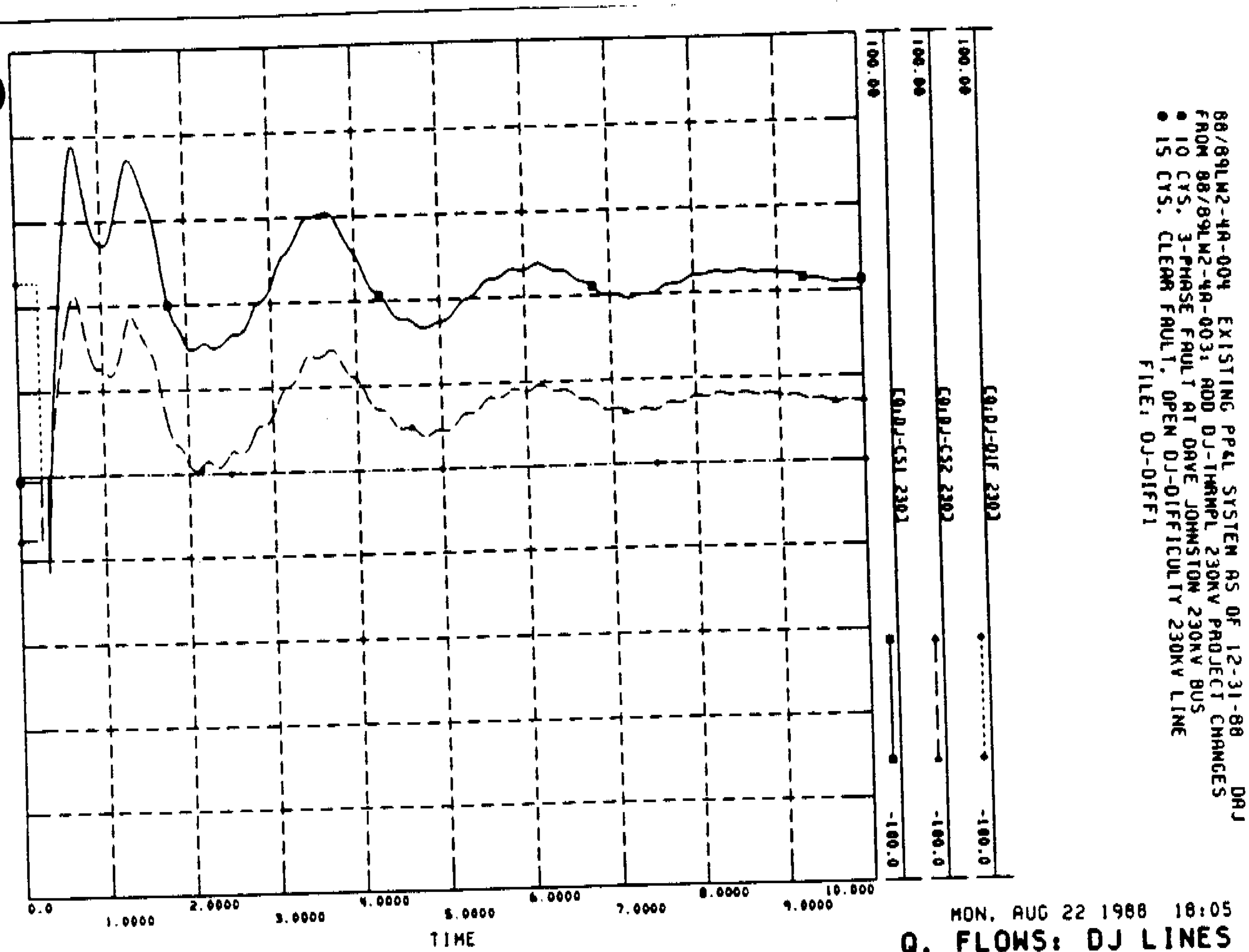
MON, AUG 22 1988 18:05
P. FLOWS: WYOMING AREA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FROM 88/89LW2-4A-003; ADD DJ-THAMPL 230KV PROJECT CHANGES
● 10 CYS. 3-PHASE FAULT AT DAVE JOHNSTON 230KV BUS
● 15 CYS. CLEAR FAULT, OPEN DJ-DIFFICULTY 230KV LINE
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[Q]DJ-CS2 230]
[Q]DJ-DIF 230]
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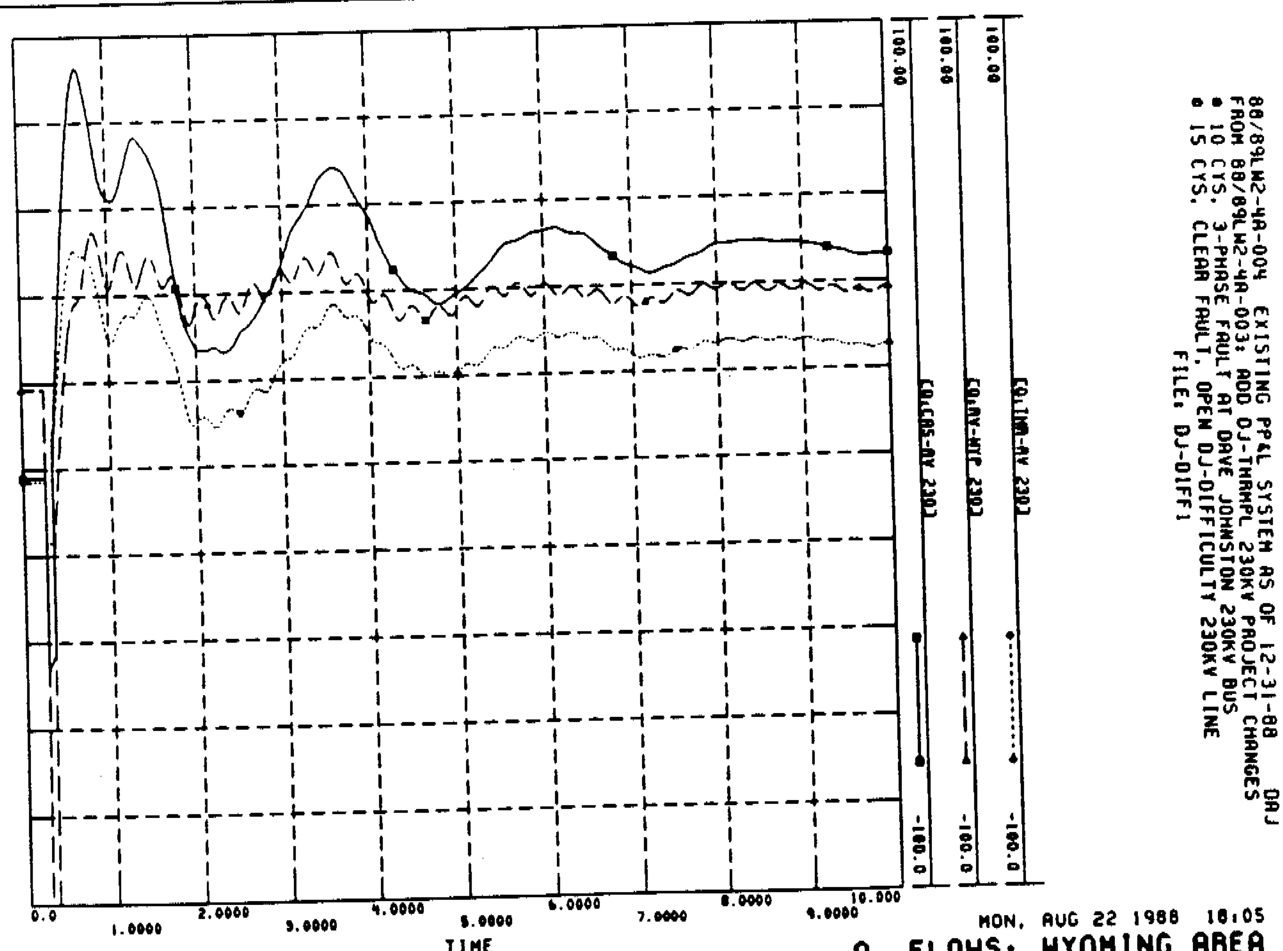
TIME
MON. AUG 22 1988 18:05
Q. FLOWS: DJ LINES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FROM 88/89LW2-4A-003; ADD DJ-THAMPL 230KV PROJECT CHANGES
● 10 CYS. 3-PHASE FAULT AT DAVE JOHNSTON 230KV BUS
● 15 CYS. CLEAR FAULT, OPEN DJ-DIFFICULTY 230KV LINE
FILE: DJ-DIFF1
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TIME
MON. AUG 22 1988 18:05
Q. FLOWS: WYOMING AREA

88/89LW2-4A-004 EXISTING PP&L SYSTEM AS OF 12-31-88 DAJ
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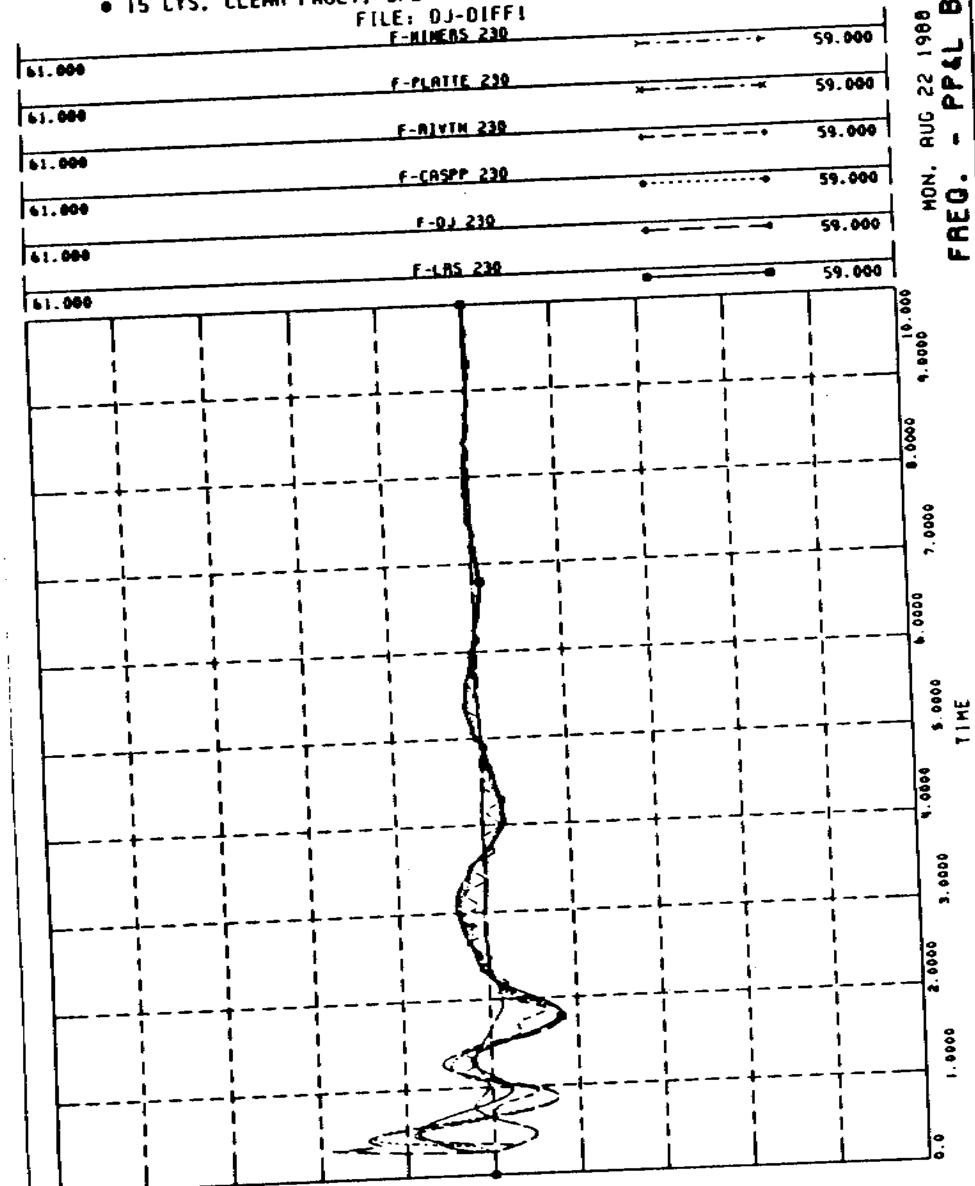
FILE: DJ-DIFF1



MON, AUG 22 1988 18:05
FREQ. - PP&L BUSES

88/89LW2-4A-004 EXISTING PP&L SYSTEM AS OF 12-31-88 DAJ
FROM 88/89LW2-4A-003: ADD DJ-THAMPL 230KV PROJECT CHANGES
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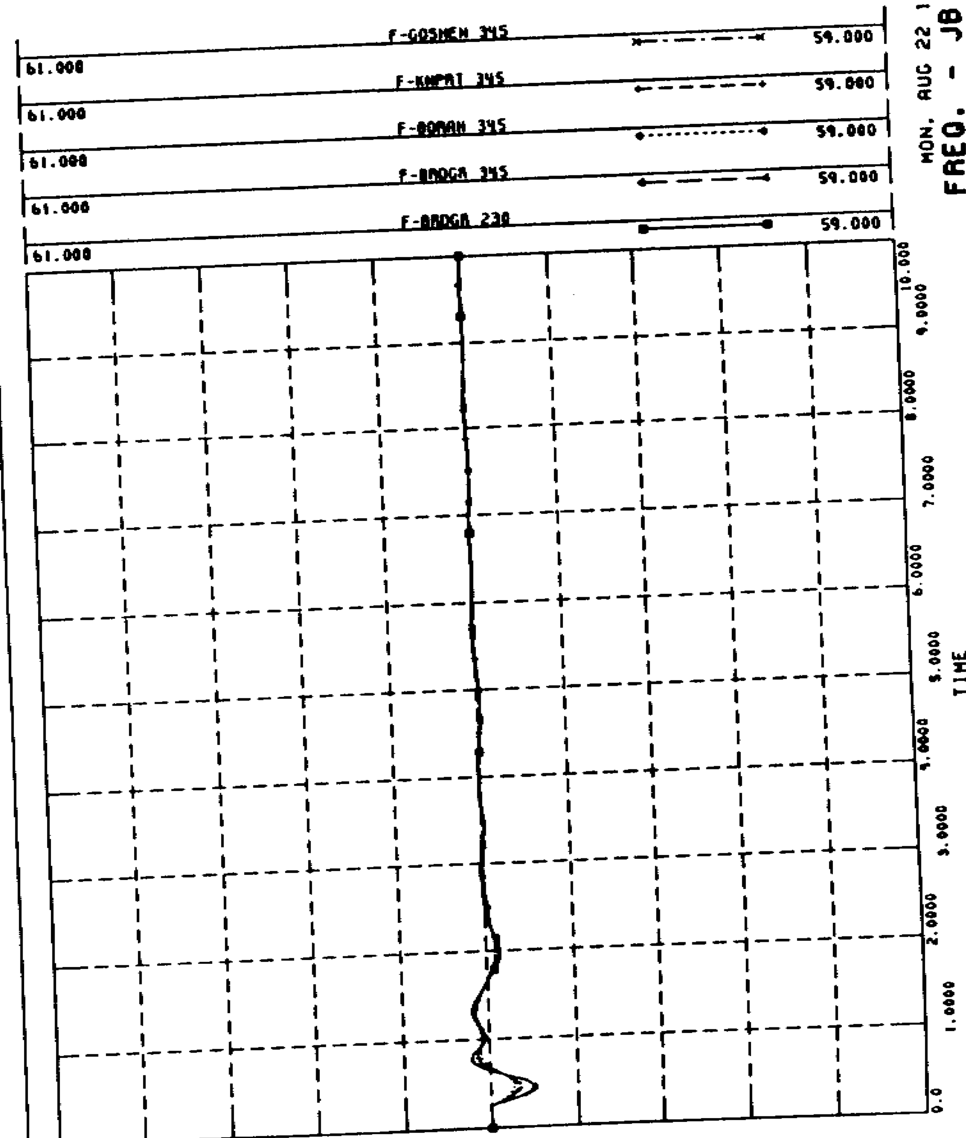
● 15 CYS. CLEAR FAULT, OPEN DJ-DIFFICULTY 230KV LINE
FILE: DJ-DIFF1



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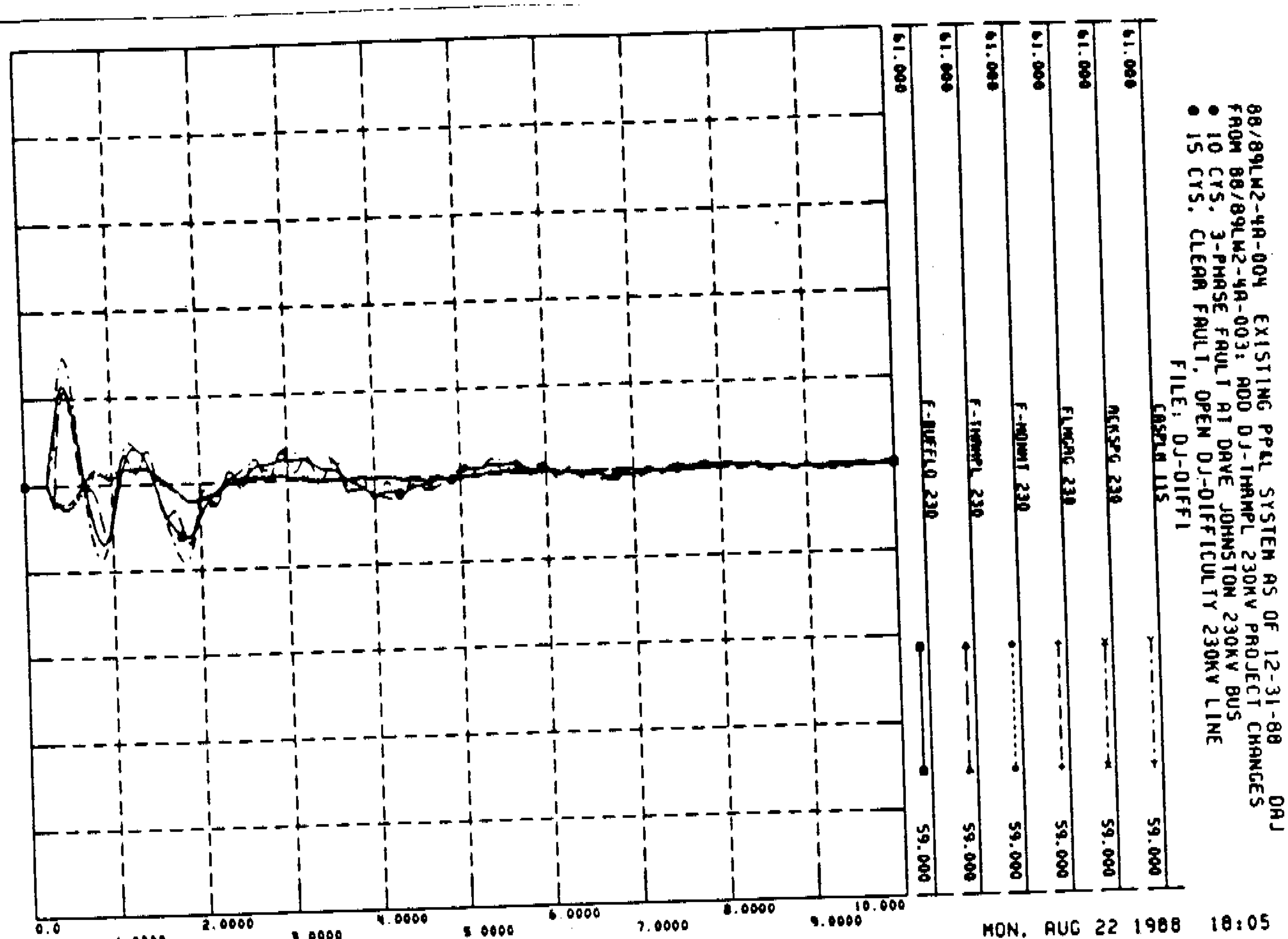
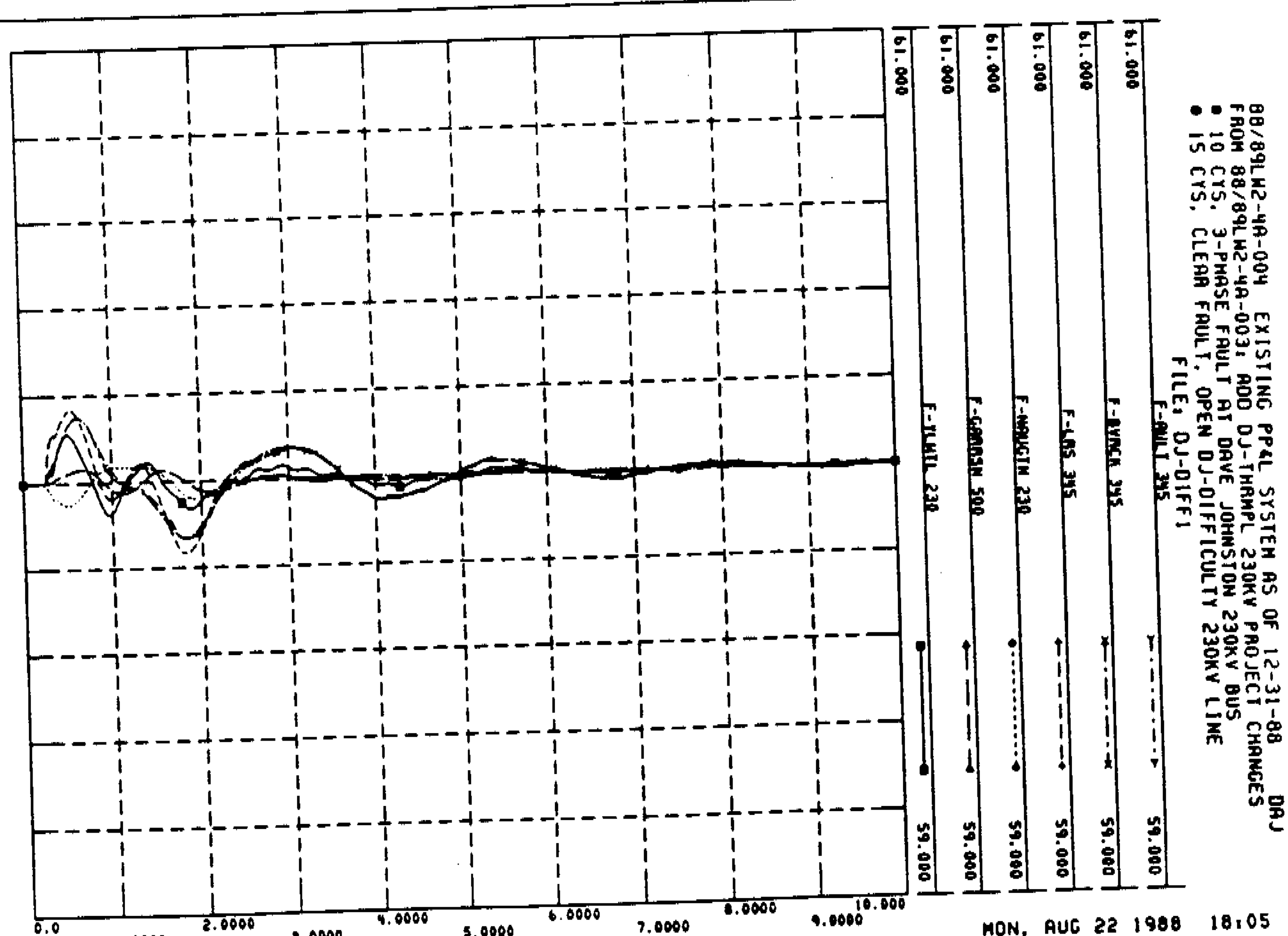
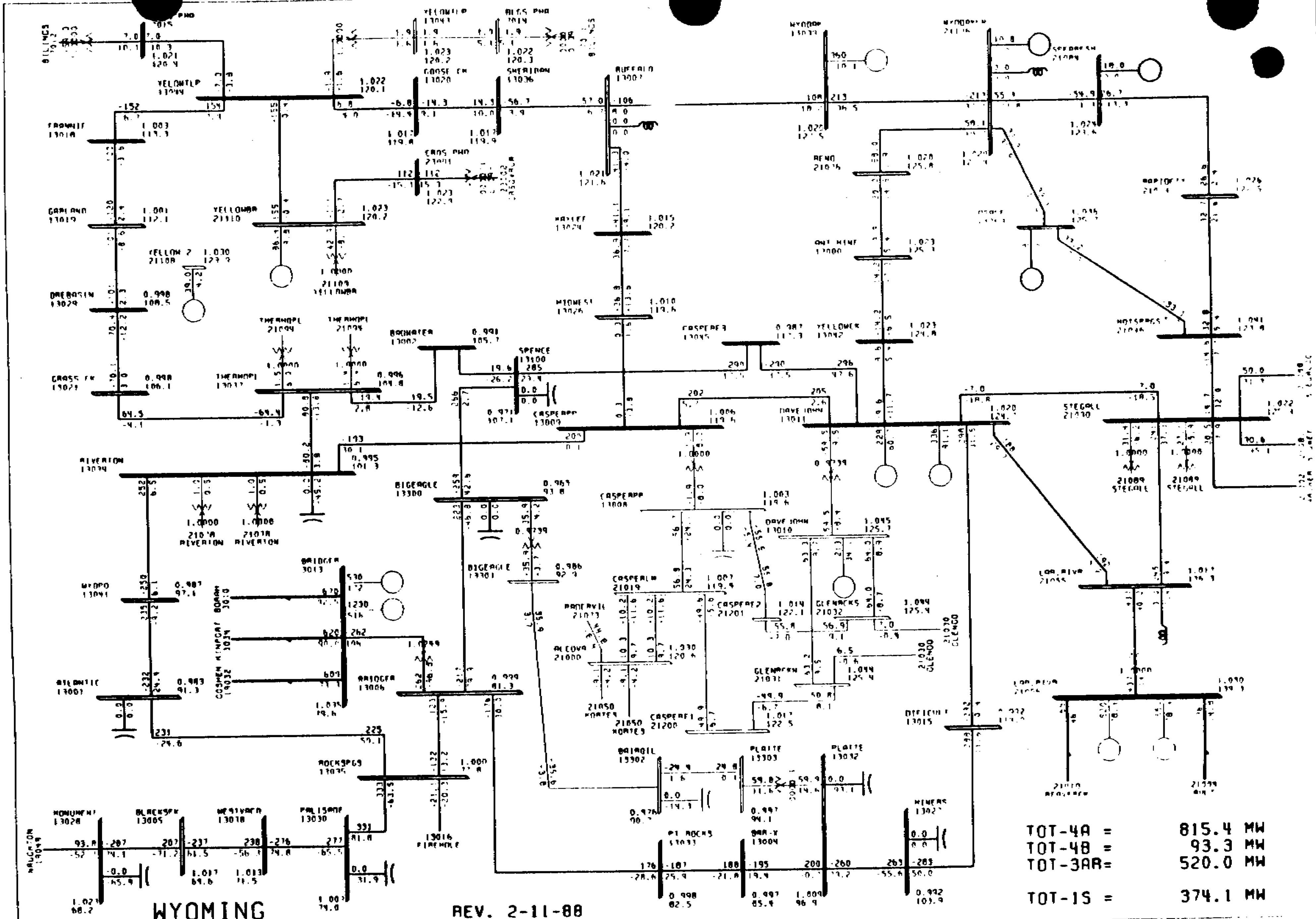
FREQ. - JB SYSTEM



FREQ. - WYOMING BUSES



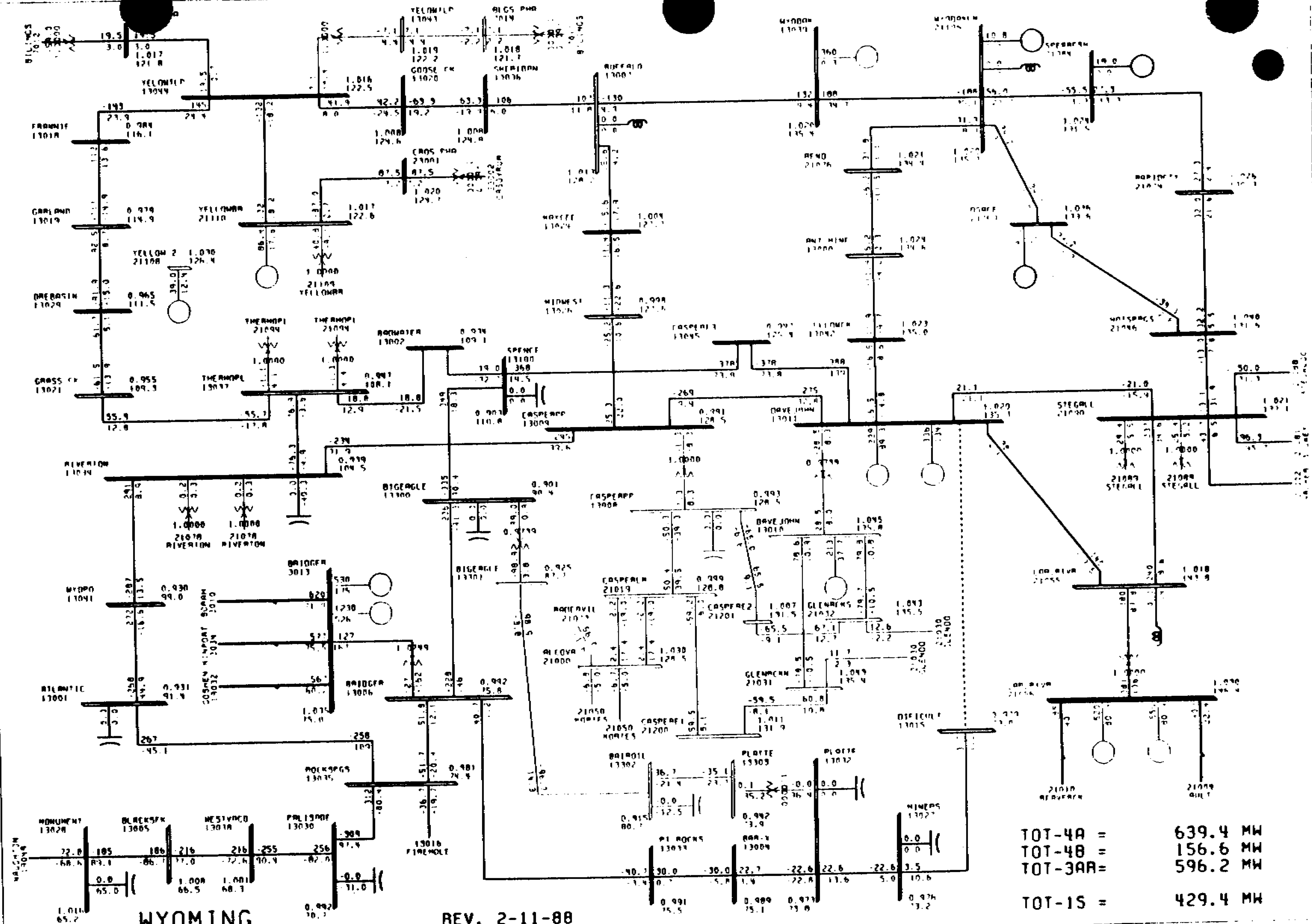
FREQ. - BOUNDARY BUSES



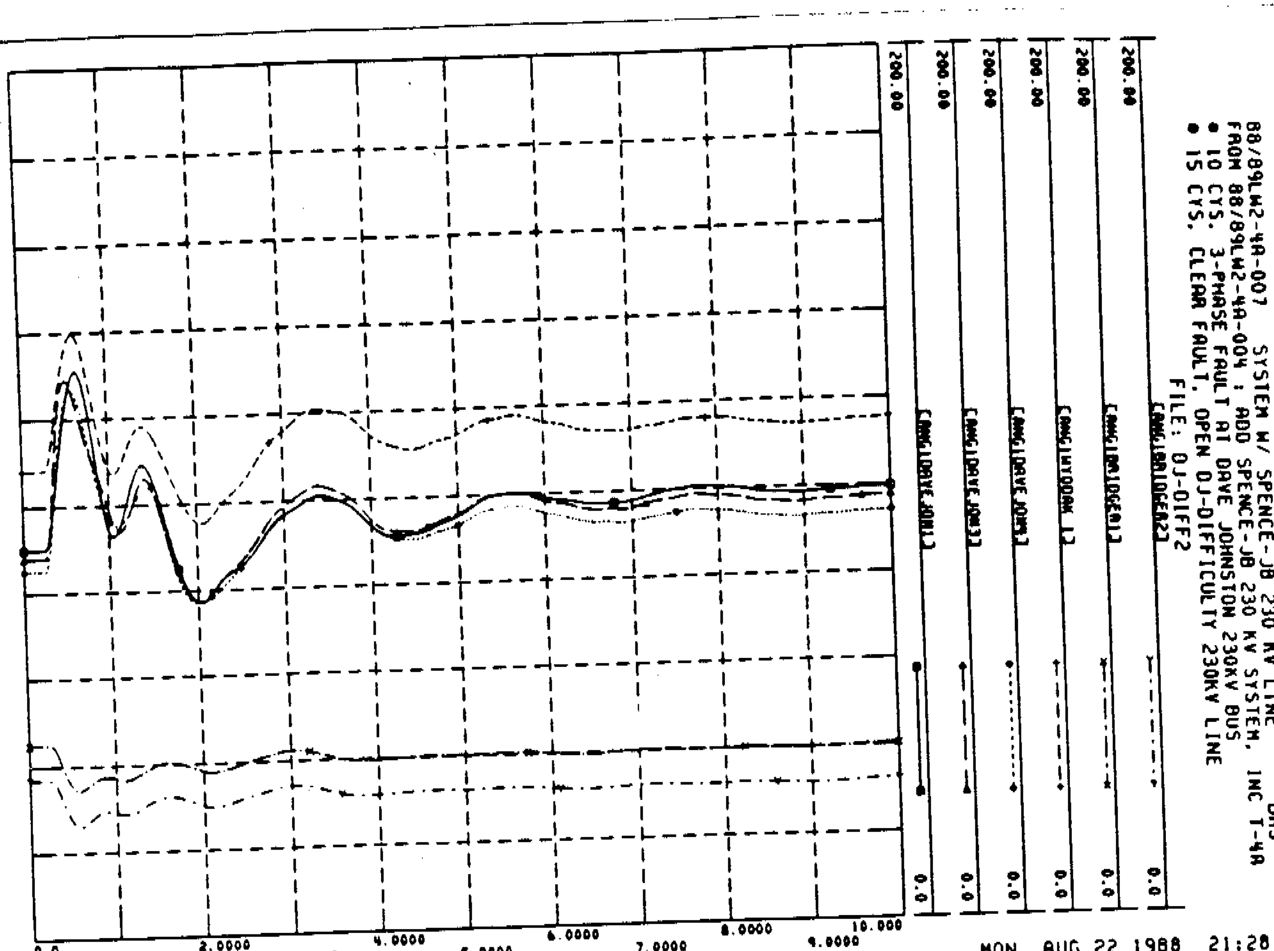
88/89LW2-4A-007 SYSTEM W/ SPENCE-JB 230 KV LINE DAJ
FROM 88/89LW2-4A-004 : ADD SPENCE-JB 230 KV SYSTEM, INC T 4A
TRANSMISSION SYSTEM PLOT TUE, AUG 23 1988 15:46

0.950UV 1.050OV
KV: ≤161 ≤230 ≤345

BUS - VOLTAGE(PU) ANGLE
BRANCH - MW/MVAR
EQUIPMENT MW MVAR

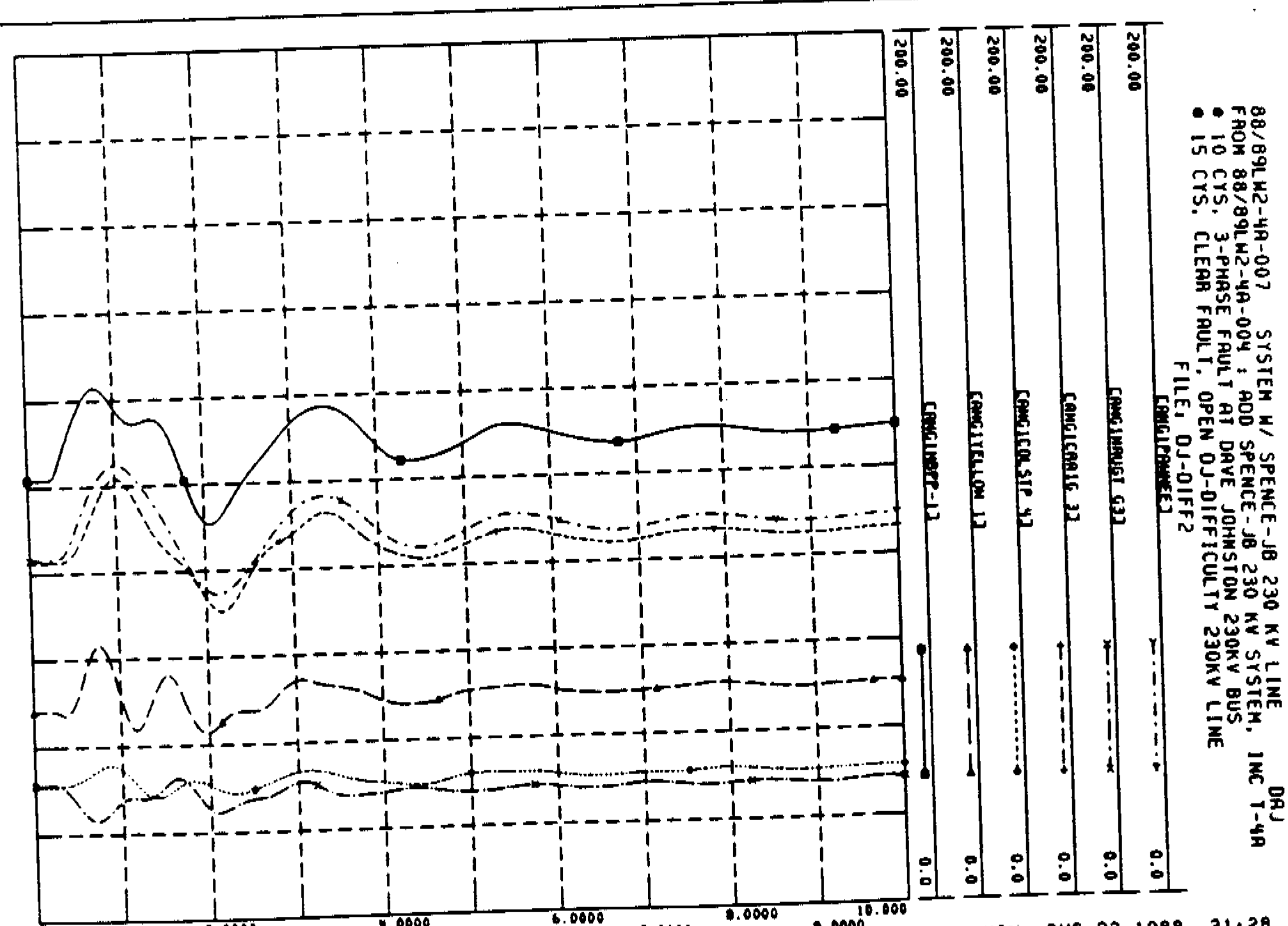


88/89LW2-4A-007A SYSTEM W/ SPENCE-JB 230 KV LINE DAI FROM 88/89LW2-4A-007 : OUTAGE OF DJ-DIFFICULTY 230KV LINE TRANSMISSION SYSTEM PLOT TUE, AUG 23 1988 15:50	KV: ≤161 , ≤230 , ≤345	BUS - VOLTAGE(PU) ANGLE BRANCH - MW MVAR EQUIPMENT - MW MVAR



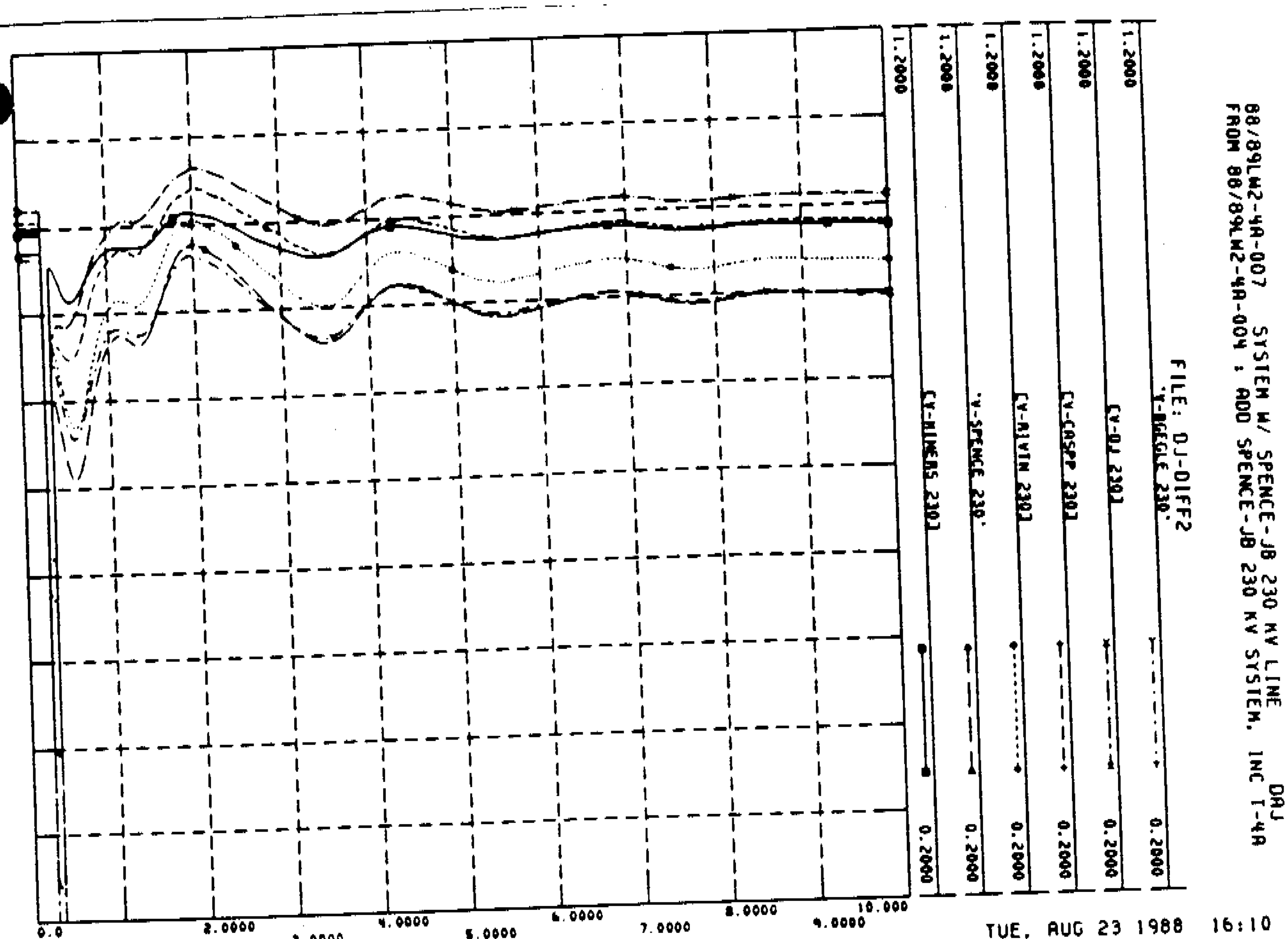
MON. AUG 22 1988 21:28

ROTOR ANGLES - PP&L UNITS

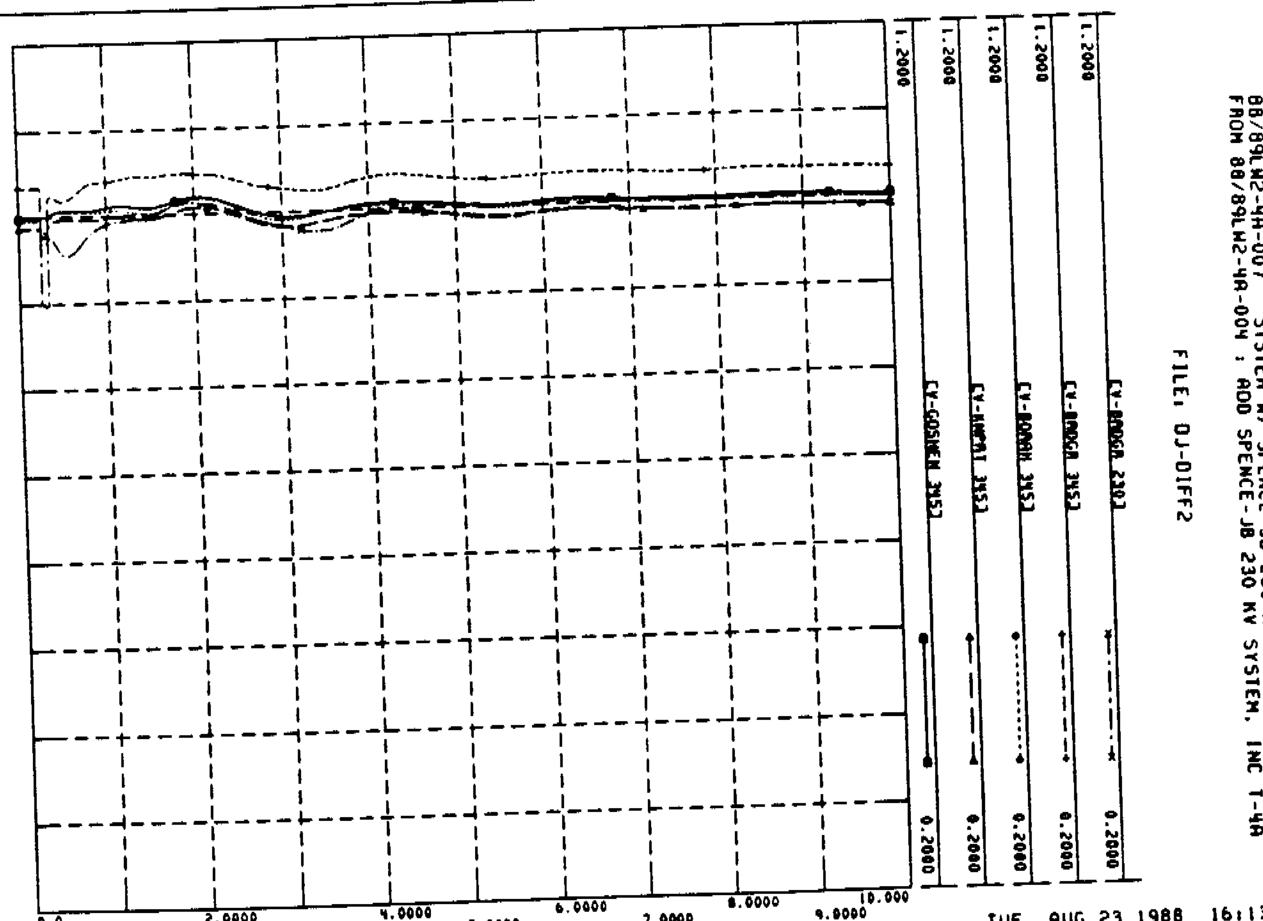


MON. AUG 22 1988 21:28

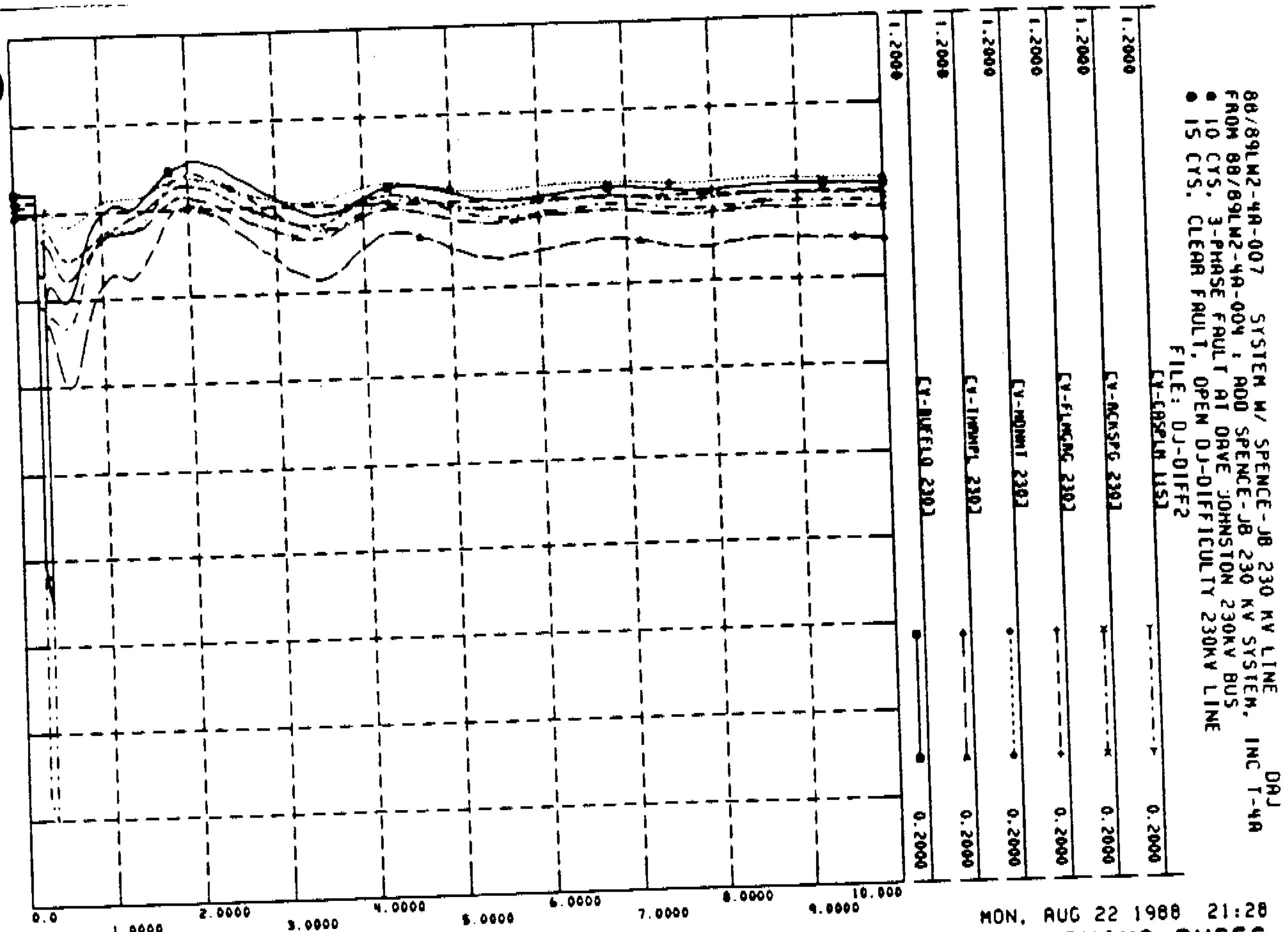
ROTOR ANGLES - OTHERS



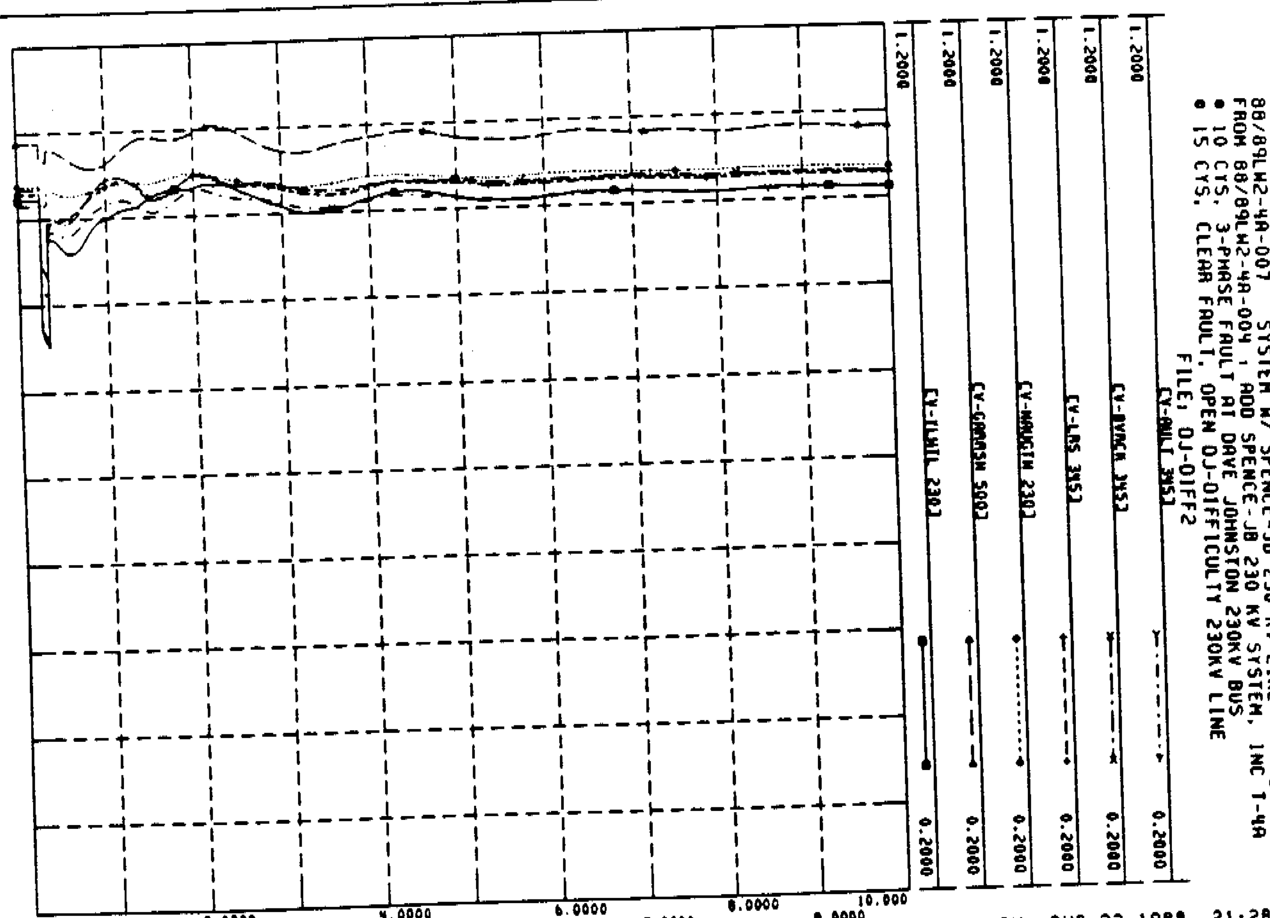
VOLTAGES - PP&L BUSES



VOLTAGES - JB SYSTEM

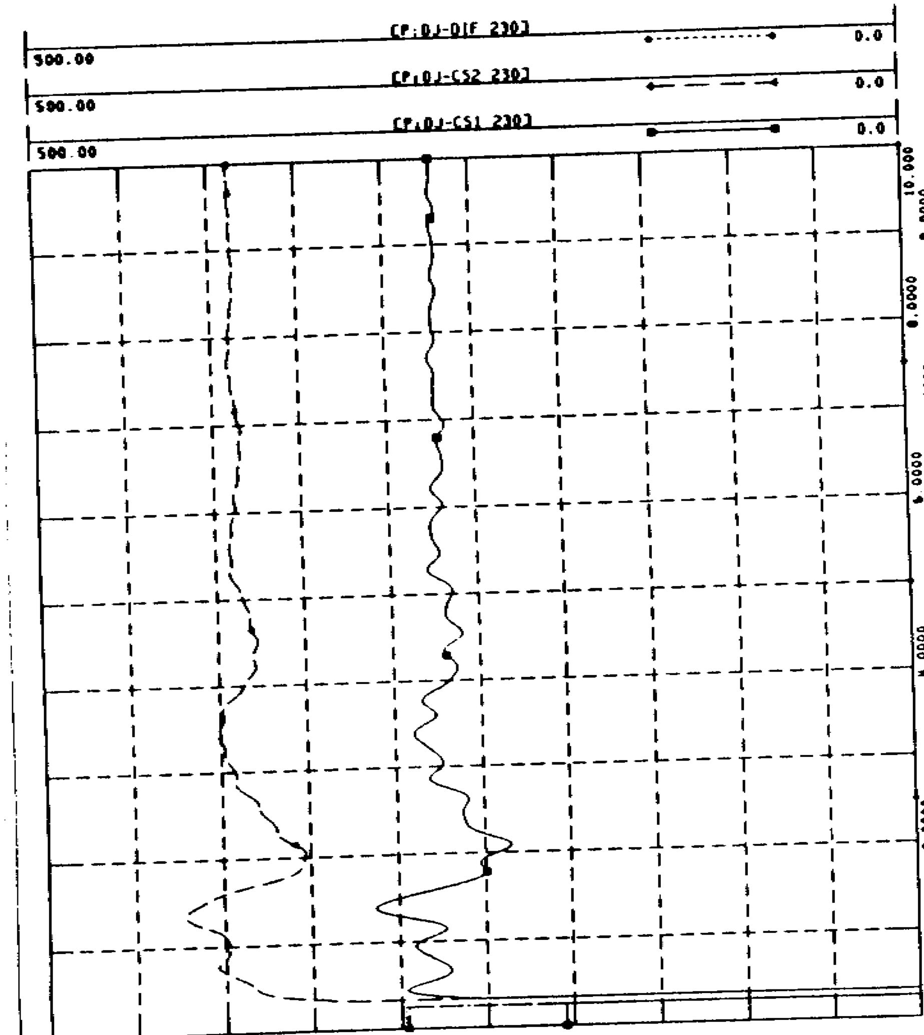


VOLTAGES - WYOMING BUSES



VOLTAGES - BOUNDARY BUSES

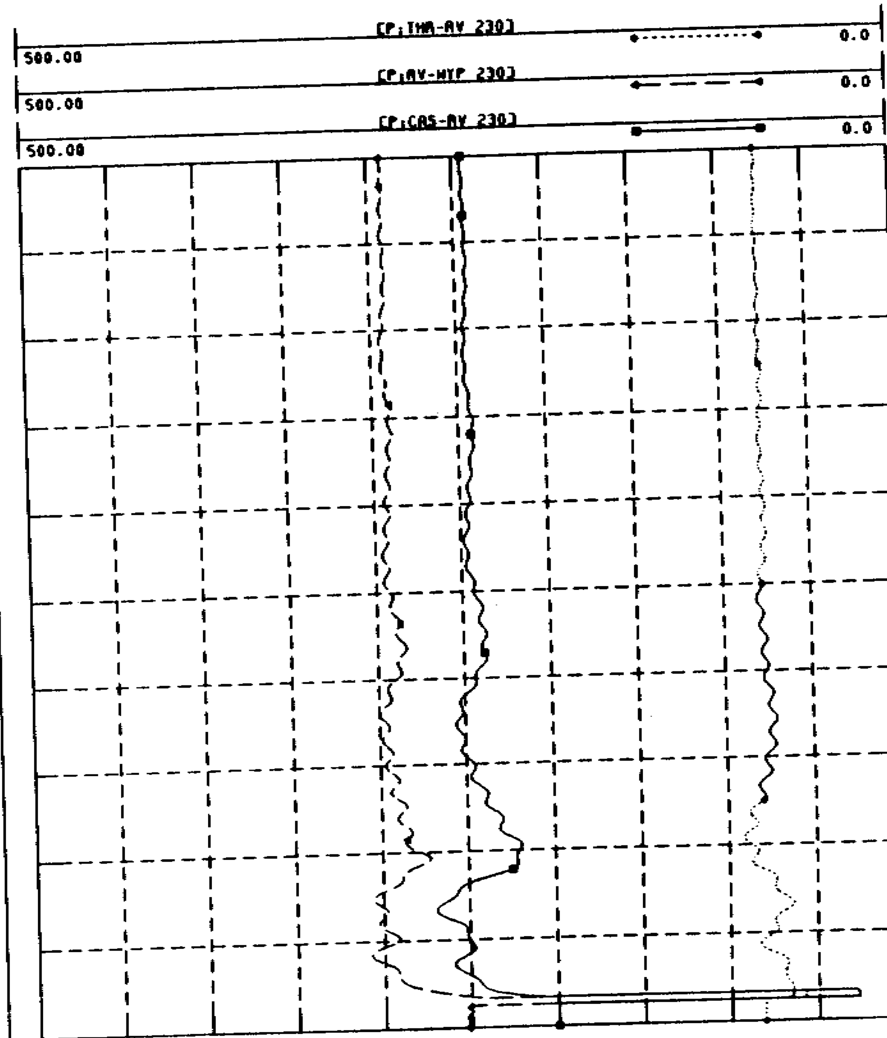
88/89LW2-4A-007 SYSTEM W/ SPENCE-JB 230 KV LINE DAJ
FROM 88/89LW2-4A-004 : ADD SPENCE-JB 230 KV SYSTEM, INC T-4A
● 10 CYS, 3-PHASE FAULT AT DAVE JOHNSTON 230KV BUS
● 15 CYS, CLEAR FAULT, OPEN DJ-DIFFICULTY 230KV LINE
FILE: DJ-DIFF2



MON. AUG 22 1988 21:28

P. FLOW : DJ LINES

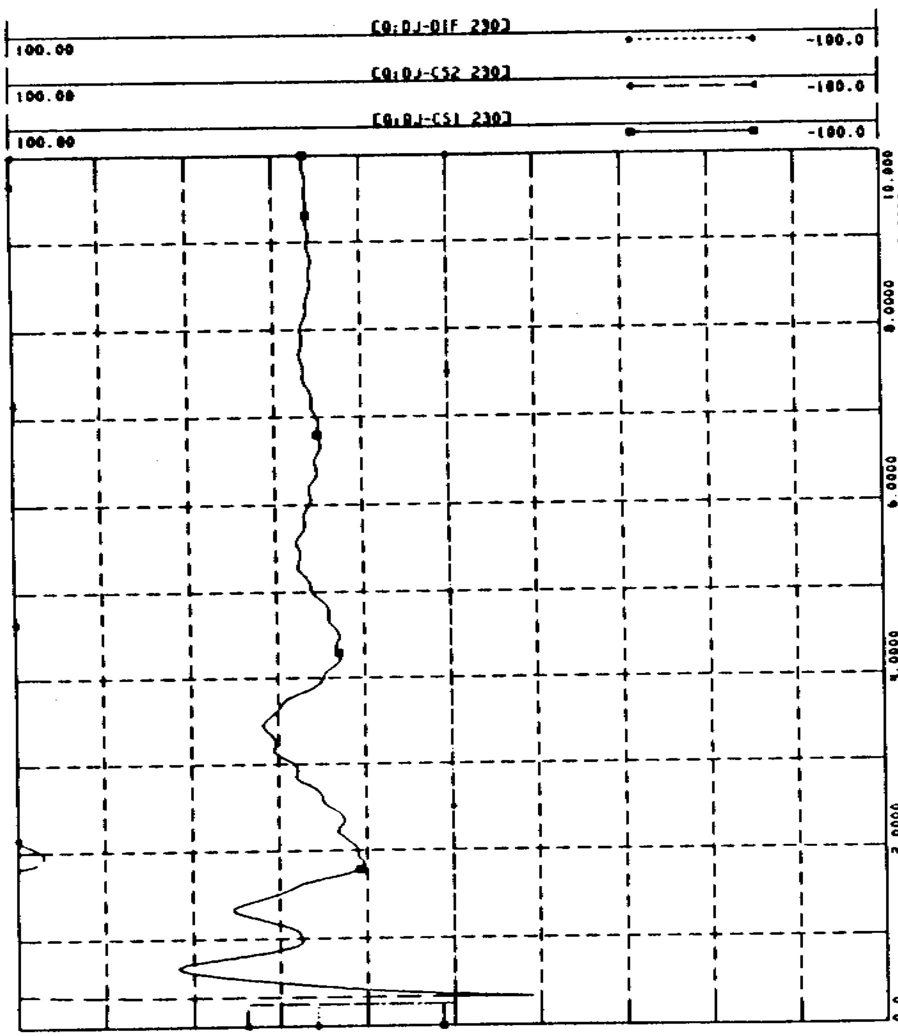
88/89LW2-4A-007 SYSTEM W/ SPENCE-JB 230 KV LINE DAJ
FROM 88/89LW2-4A-004 : ADD SPENCE-JB 230 KV SYSTEM, INC T-4A
● 10 CYS, 3-PHASE FAULT AT DAVE JOHNSTON 230KV BUS
● 15 CYS, CLEAR FAULT, OPEN DJ-DIFFICULTY 230KV LINE
FILE: DJ-DIFF2



MON. AUG 22 1988 21:28

P. FLOWS: WYOMING AREA

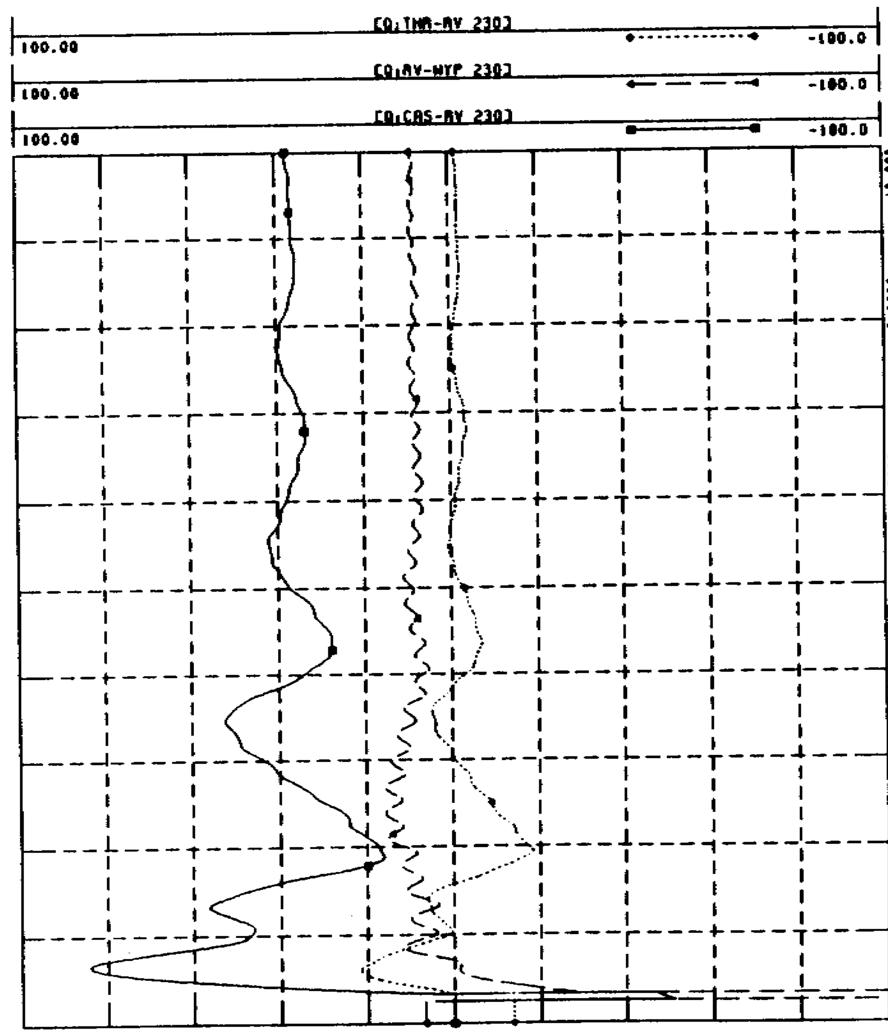
88/89LW2-4A-007   SYSTEM W/ SPENCE-JB 230 KV LINE   DAJ
FROM 88/89LW2-4A-004 : ADD SPENCE-JB 230 KV SYSTEM, INC T-4A
● 10 CYS, 3-PHASE FAULT AT DAVE JOHNSTON 230KV BUS
● 15 CYS, CLEAR FAULT, OPEN DJ-DIFFICULTY 230KV LINE
FILE: DJ-DIFF2



MON, AUG 22 1988 21:28

Q. FLOWS: DJ LINES

88/89LW2-4A-007   SYSTEM W/ SPENCE-JB 230 KV LINE   DAJ
FROM 88/89LW2-4A-004 : ADD SPENCE-JB 230 KV SYSTEM, INC T-4A
● 10 CYS, 3-PHASE FAULT AT DAVE JOHNSTON 230KV BUS
● 15 CYS, CLEAR FAULT, OPEN DJ-DIFFICULTY 230KV LINE
FILE: DJ-DIFF2



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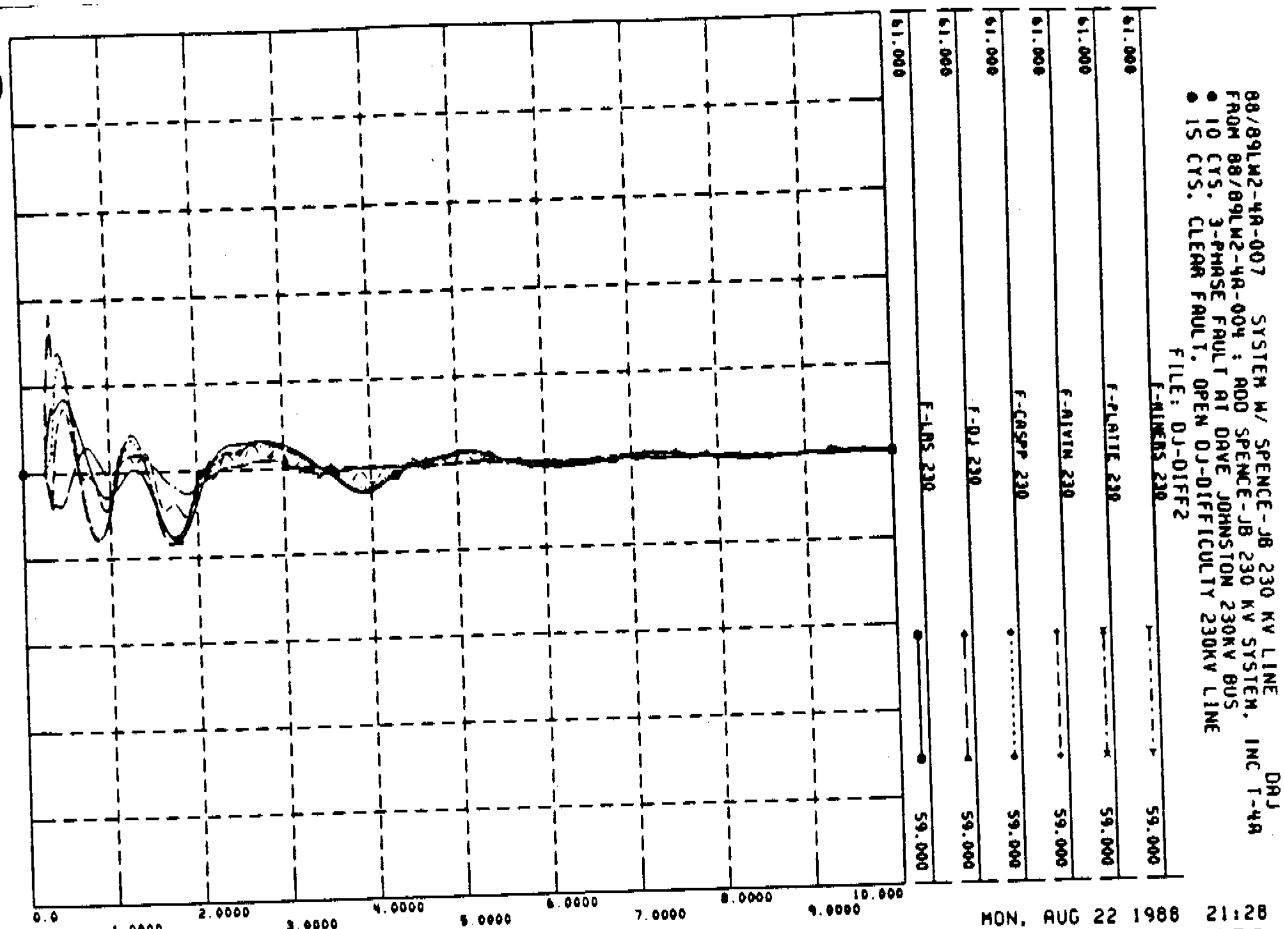
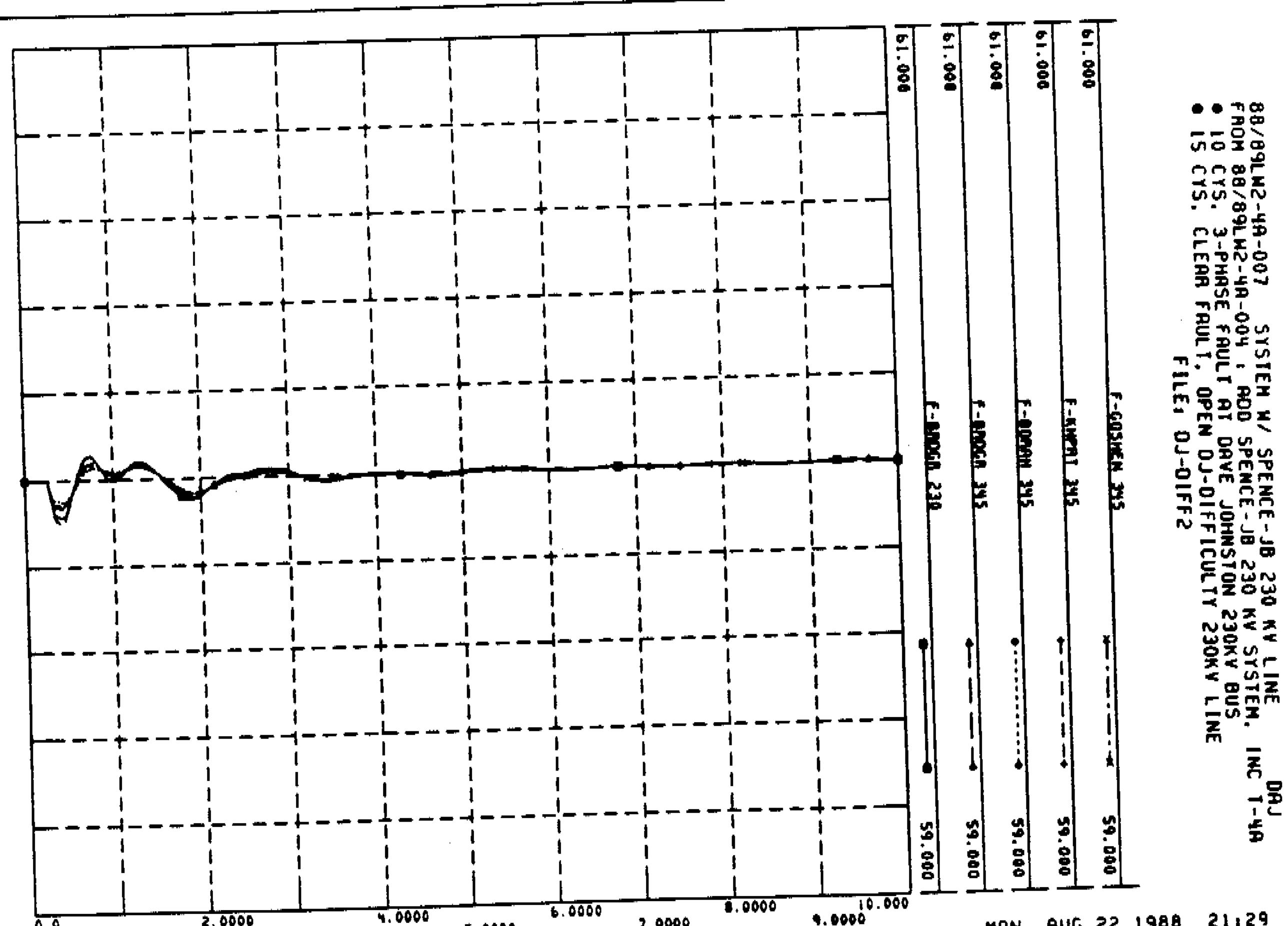
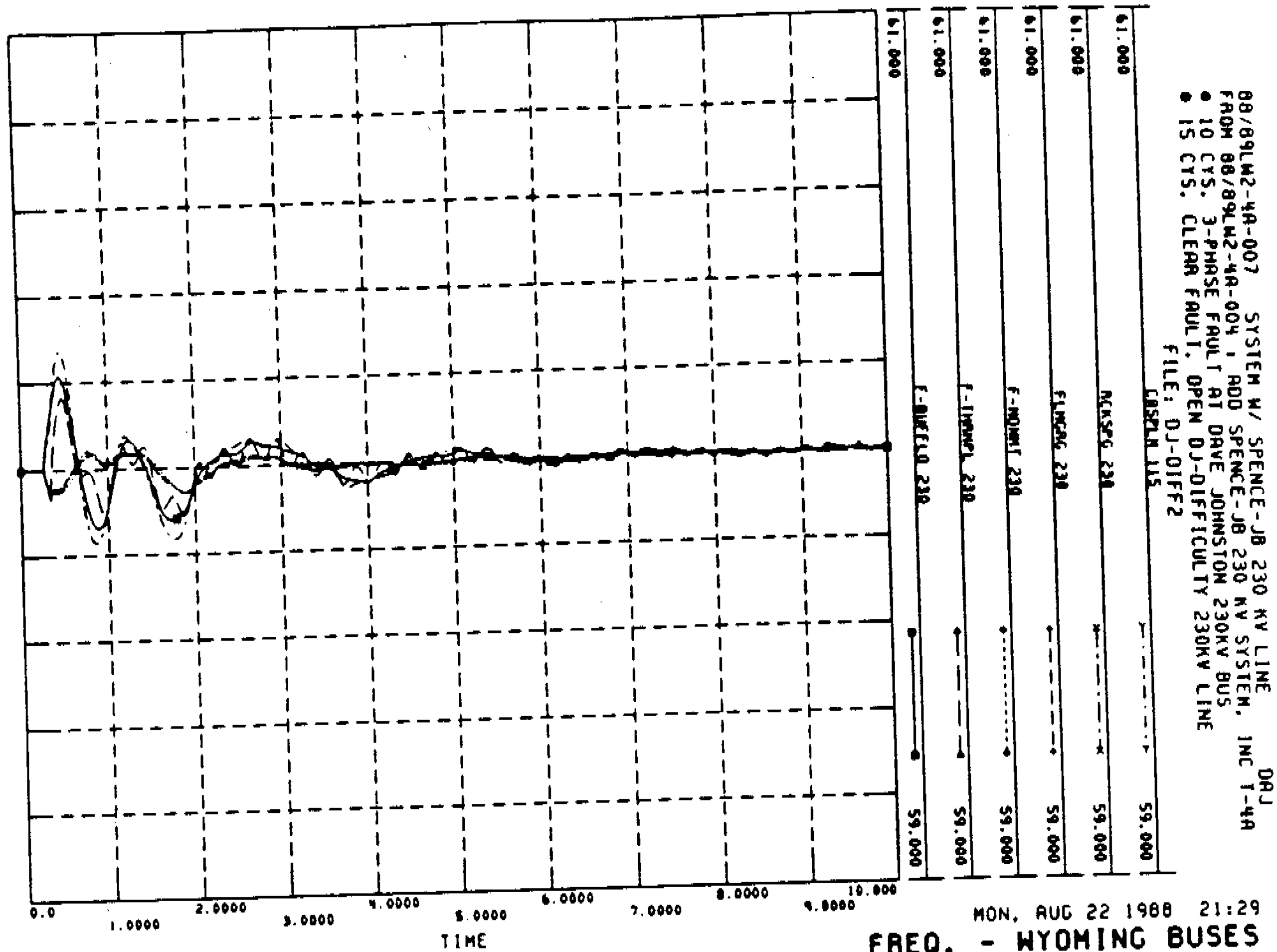
Q. FLOWS: WYOMING AREA



FREQ. - PP&L BUSES



FREQ. - JB SYSTEM


88/89LW2-4A-007 SYSTEM W/ SPENCE-JB 230 KV LINE DAJ
FROM 88/89LW2-4A-004 ; ADD SPENCE-JB 230 KV SYSTEM, INC T-4A
● 10 CYS. 3-PHASE FAULT AT DAVE JOHNSTON 230KV BUS
● 15 CYS. CLEAR FAULT, OPEN DJ-DIFFICULTY 230KV LINE
FILE: DJ-DIFF2
CASPLN 115 61.000 59.000
ACKSPG 230 61.000 59.000
FLMGRG 230 61.000 59.000
F-MONMT 230 61.000 59.000
F-THRMPL 230 61.000 59.000
F-BUFFLO 230 61.000 59.000
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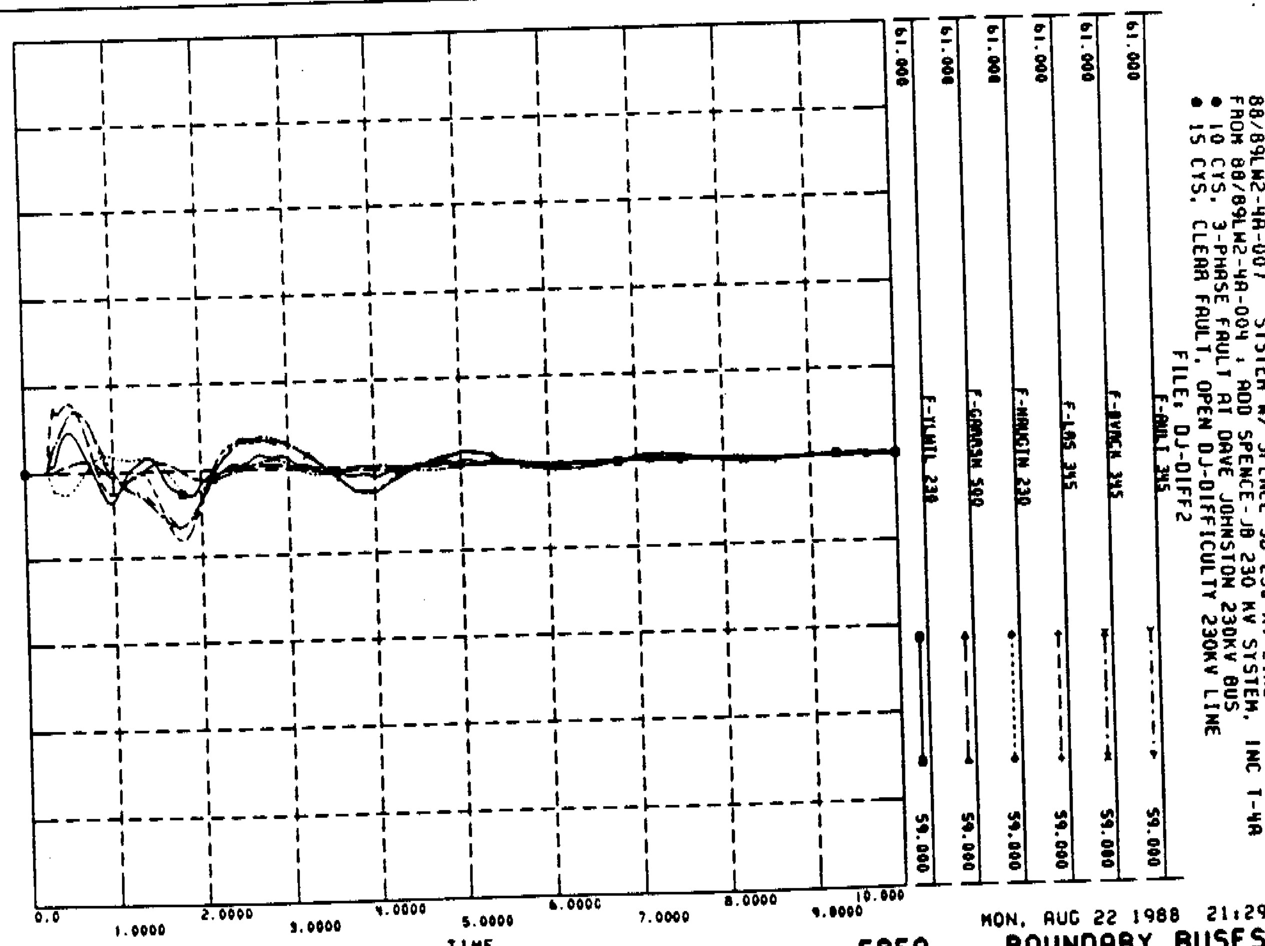
TIME
MON, AUG 22 1988 21:29
FREQ. - WYOMING BUSES


88/89LW2-4A-007 SYSTEM W/ SPENCE-JB 230 KV LINE DAJ
FROM 88/89LW2-4A-004 ; ADD SPENCE-JB 230 KV SYSTEM, INC T-4A
● 10 CYS. 3-PHASE FAULT AT DAVE JOHNSTON 230KV BUS
● 15 CYS. CLEAR FAULT, OPEN DJ-DIFFICULTY 230KV LINE
FILE: DJ-DIFF2
F-AULT 345 61.000 59.000
F-BYRCK 345 61.000 59.000
F-LAS 345 61.000 59.000
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F-YLWTL 230 61.000 59.000
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TIME
MON, AUG 22 1988 21:29
FREQ. - BOUNDARY BUSES

FORECAST OPERATING POINTS

4A/4B NOMOGRAM

ON PEAK

	1989 S	1989-90 W	1990 S	1990-91 W	1991 S	1991-92 W	1992 S	1992-93 W	1993 S
NATIVE LOAD - 4A	378	395	387	440	435	453	449	459	452
WYODAK/D.J. SURPLUS 4A	0	0	0	0	0	0	0	0	0
TOTAL 4A REQUIREMENTS	378	395	387	440	435	453	449	459	452
NATIVE LOAD - 4B	247	275	253	307	284	316	293	320	295
WAPA CONTRACT	170	170	170	170	170	170	170	170	170
TOTAL 4B REQUIREMENTS	417	445	423	477	454	486	463	490	465
NON-SIMULTANEOUS									
4A - REC (E TO W)	180	150	170	290	260	230	300	260	270
4B - REC (S TO N)	180	140	170	270	380	160	300	150	180

OFF PEAK

	* 1989 S	1989-90 W	* 1990 S	1990-91 W	* 1991 S	1991-92 W	* 1992 S	1992-93 W	* 1993 S
NATIVE LOAD - 4A	273	278	273	285	309	319	319	329	321
WYODAK/D.J. SURPLUS 4A	436	406	447	391	375	318	354	297	352
TOTAL 4A REQUIREMENTS	709	684	720	676	684	637	673	626	673
NATIVE LOAD - 4B	127	138	127	141	144	158	148	163	149
WAPA CONTRACT	170	170	170	170	170	170	170	170	170
TOTAL 4B REQUIREMENTS	297	308	297	311	314	328	318	333	319

NOTE: * BASIS FOR REC CALCULATIONS FOR PATH M,N,O

DISK: LWS12 FILE:REC4A4B
DEC 12,1988

SELECTED PAGES OF "AGREEMENT FOR TRANSMISSION SERVICES" BETWEEN IPC AND PP&L

AGREEMENT FOR TRANSMISSION SERVICES
BETWEEN IDAHO POWER COMPANY
AND PACIFIC POWER & LIGHT COMPANY

This Agreement, entered into as of the 10th day of September, 1980, is made by and between Idaho Power Company, a Maine Corporation, hereinafter referred to as "Idaho", and Pacific Power & Light Company, a Maine Corporation, hereinafter referred to as "Pacific" which are hereinafter collectively referred to as the "Parties" or, individually referred to as "Party".

W I T N E S S E T H:

WHEREAS, the Parties are engaged in the generation, transmission and distribution of electric power and energy, and are interconnected with other utility systems in the Western United States; and

WHEREAS, the Parties have entered into the Agreement for the Operation of the Jim Bridger Project, which Agreement is dated September 22, 1969, hereinafter referred to as the "Operation Agreement";

WHEREAS, on the 26th day of October, 1979, the Parties executed a Letter Agreement which set forth the considerations for and the scope of an Agreement under which Idaho would provide transmission services to Pacific for the westerly transfer of up to 1600 megawatts of Pacific's Wyoming generation; and

WHEREAS, this Agreement is executed for the purpose of implementing the understandings contained in the may schedule to Idaho and Idaho will schedule west for Pacific transfers of up to 1600 mw of the actual combined capability of the Midpoint-Medford line and Idaho's western interconnections; provided, however, that at all times and under any conditions Idaho shall be entitled to the use of not less than 570 mw of westbound capability in its existing western interconnections.

(H) (1) - Upon completion of the Midpoint-Medford and Kinport-Midpoint lines, in addition to the payments provided for in (F) above, Pacific shall pay to Idaho a use-of-facilities charge for the following facilities:

(a) Those facilities required to connect the Midpoint-Medford line to the Idaho system. A description of these facilities is contained in Paragraph 2.1 of Part 2 of the attached Exhibit "B". The line terminal and transformation facilities at Midpoint required for the Midpoint-Medford line will be constructed by Pacific and conveyed to Idaho in such manner as to preserve first-owner status of Idaho under the terms of a separate purchase and sale agreement known as the Midpoint Ownership Agreement.

(b) Those additional facilities required to permit transfers of the 1600 megawatts of capacity provided in (G) above. A description of these additional facilities is contained

SELECTED PAGES OF TRANSMISSION AGREEMENT BETWEEN BPA AND PP&L

(AUTHENTICATED COPY)

Contract No. DE-MS79-79BP90091

9-11-79

TRANSMISSION AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFIC POWER & LIGHT COMPANY

(in conjunction with the interconnection at Summer Lake and Malin substations of the Company's Midpoint-Medford 500 kV transmission line with the Federal Transmission System)

Index to Sections

- -

This AGREEMENT, executed September 27, 1979, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PACIFIC POWER & LIGHT COMPANY (Company), a corporation of the State of Maine,

W I T N E S S E T H :

WHEREAS the Company expects to construct a 500 kV transmission line from a point near Twin Falls, Idaho, to Medford, Oregon (Midpoint-Medford Line), to transmit electric power and energy from resources which it owned or which were under construction by it, as of September 2, 1977, in Wyoming and adjacent states (Eastern System) to the Pacific Northwest; and

WHEREAS the parties desire to interconnect the Midpoint-Medford Line with the Federal Transmission System and the two 500 kV a-c circuits of the Pacific Northwest-Pacific Southwest intertie facilities (AC-Intertie) at the Malin substation (Malin Tie); and

WHEREAS the parties hereto have, by joint studies and a letter of September 2, 1977, agreed to certain principles concerning the conditions under which the Malin Tie will be established and under which transmission services will be provided; and associated losses under an appropriate firm wheeling agreement. Use of one party's capacity in either segment of the Buckley-Malin line by the other shall be subject to availability, as determined by the other, and shall be subject to payment and loss provisions agreed upon by the parties.

Commencing on the effective date of the exchange of capacity and continuing until the earlier of (1) the Date of Commercial Operation of an additional high voltage transmission line between the Federal Transmission System and the Idaho Power Company system or (2) January 1, 1987, if Bonneville requires additional capacity to the east in excess of the 350 megawatts capacity of its present interconnections with Idaho Power Company at LaGrande and Hines to serve Bonneville's own loads, Bonneville shall have the use of 200 megawatts of scheduling capability in the Midpoint-Summer Lake line segment to the point where the Company's facilities interconnect with facilities of Idaho Power Company. Losses associated with amounts of power transmitted over the Company's Midpoint-Summer Lake line segment shall be assessed in a manner agreed upon by the parties. There shall be no transmission charges for such transmission service.

5. Transmission of Electric Power and Energy. The parties hereto agree that the Company may, upon 30 days' notice and for a period of not less than 12 months, designate the power transmitted under section 5(a) to meet its contractual rights and obligations in the Walla Walla and Yakima Areas to the extent the Company owns or leases facilities other than Bonneville's which allow it to serve such loads. During such period Bonneville shall deem all or a portion of the deliveries under section 5(a) to be made to the Walla Walla and Yakima Areas; provided, however, that the Company shall continue to deliver losses and pay for transmission services as if such power were designated to the Points of Delivery.

(a) During each hour of the term hereof, the Company shall make available to Bonneville at the Points of Interconnection and Bonneville shall make available

Exhibit B

Transmission Services Tariff

FERC ELECTRIC TARIFF

Original Volume No. 5

of

PACIFICORP, doing business as
PACIFIC POWER & LIGHT COMPANY or
UTAH POWER & LIGHT COMPANY

filed with

FEDERAL ENERGY REGULATORY COMMISSION

Communications concerning this Tariff should be addressed to:

Robert M. Smith
Sr. Vice President
920 SW Sixth Avenue
Portland, Oregon 97204

Original Volume No. 5
(Transmission Services)

Table of Contents

GENERAL TERMS AND CONDITIONS FOR
SERVICE SCHEDULES TS-1, TS-2, TS-3, TS-4 AND TS-5

AVAILABILITY:

This Tariff is available to any eligible utility (Utility) as specified in the Federal Energy Regulatory Commission's (FERC) Opinion No. 318 (Opinion No. 318), for transmission service by PacifiCorp doing business as Pacific Power & Light Company or Utah Power & Light Company (Company). An executed Transmission Service Agreement (Service Agreement) shall be required between the Utility and the Company prior to the commencement of any transmission service and each Service Agreement shall be filed with the FERC.

SCHEDULING:

All power and energy to be transmitted by the Company under this Tariff shall be scheduled in advance pursuant to the terms of the Service Agreement. All such schedules of power and energy shall be deemed to be delivered by the Company at the Point(s) of Delivery (POD) and received by the Company at the Point(s) of Receipt (POR) in the amounts and during the times so scheduled. Any scheduling arrangements, including any associated costs or losses, that may be required with an authorized agent(s) at either the POD or the POR shall be the responsibility of the Utility. The Utility shall provide written notification to the Company identifying any such agent(s) and authorizing such agent(s) to schedule all power and energy to be transmitted by the Company pursuant to the Service Agreement on behalf of the receiving party at the POD or the delivering party at the POR. All schedules of power and energy to be transmitted by the Company shall be in accordance with normal utility scheduling practices.

CONTINUITY OF SERVICE:

The Company will make reasonable provision to furnish the transmission services available under this Tariff, but does not guarantee that such services will be constant or uninterrupted, and shall not be liable for any damage or claim of damage attributable to any interruption of service resulting from unavoidable accident or casualty, extraordinary action of the elements, strikes, actions of any governmental authority, litigation, or from any cause which the Company could not reasonably have foreseen and made provision against, or for any damage attributable to any interruption or discontinuance of service which, in the Company's judgement, is necessary.

INDEMNIFICATION:

Except as provided in the following paragraph, each Party to a Service Agreement under this Tariff assumes all liability for injury or damage to persons or property arising from the act or neglect of its own employees, agents or contractors and shall indemnify and hold the other harmless from any liability arising therefrom.

Notwithstanding the foregoing, no Party to a Service Agreement under this Tariff ("First Party") shall be liable, whether in contract warranty, tort or strict liability, to the other Party ("Second Party") for any injury or death to any person, or for any loss or damage to any property, caused by or arising out of an electric disturbance on the First Party's electric system, whether or not such electric disturbance resulted from the First Party's negligent, grossly negligent or wrongful act or omission, excepting only action knowingly or intentionally taken, or failed to be taken, with intent that injury or damage result therefrom, or which action is wantonly reckless. Each Second Party releases the First Party from, and shall indemnify the First Party for, any such liability. As used in this paragraph, 1) the term "Party" means, in addition to such Party itself, its directors, officers and employees; 2) the term "damage" means all damage, including consequential damage; and 3) the term: "Person" means any person, including those not connected with either Party to a Service Agreement under this Tariff.

CONFLICT OF TERMS:

In the event of a conflict between the specific terms and conditions of a Service Agreement and the General Terms and Conditions of this Tariff or the applicable Service Schedule, the specific terms and conditions of the Service Agreement shall govern.

RATE CHANGES:

Nothing contained in this Tariff, any associated Service Schedule or any Service Agreement shall be construed as affecting in any way the right of the Company to unilaterally make application to the FERC for a change in rates, charges, classification or service, or any rule, regulation or service agreement related thereto, under Section 205 of the Federal Power Act or any successor statute and pursuant to the Commission's Rules and Regulations promulgated thereunder.

BILLING:

The Company shall invoice the Utility each month for services provided under this Tariff, pursuant to the terms of the Service Agreement. All bills shall be due and payable with 15 days from the date of mailing as determined by postmark. Any amounts due and unpaid after the due date shall be termed delinquent and interest shall be added to such delinquent amount at the rate of 0.0411 percent per day (15 percent per year) until payment is received by the Company.

METERING:

If metering is specified in the Service Agreement, transmission services provided under this Tariff shall be determined from measurements by suitable meters. The metering equipment shall be inspected and tested at least once each year. Any metering equipment found to be defective or inaccurate by an error in registration of more than plus or minus two percent (2%) shall be repaired, readjusted or replaced. If any of the inspections and tests provided for herein disclose an error exceeding two percent (2%), either fast or slow, proper correction, based upon the inaccuracy found, shall be made of previous readings for the period of six (6) months immediately preceding the removal of such meter from service for test, or from the time the meter was in service since last tested, but not exceeding six (6) months, in the amount the meter shall have been shown to be in error by such test. If any meter is found not to register for any period, the Company shall make a charge for service provided but not metered, based on scheduling information or in the absence of such information on service provided under similar conditions during periods preceding or subsequent thereto, or during corresponding periods in previous years. Any correction in billing resulting from any such corrections in the meter records, shall be made in the next monthly bill rendered, and such correction, when made, shall constitute full adjustment of any claim between the parties arising out of such inaccuracy or failure of metering equipment.

DEFINITIONS:

a) Announcement Date: The date on which the Company's Notice of Announcement of Remaining Existing Capacity is published in the Federal Register.

b) Contract Demand: The maximum amount of power specified in the Service Agreement, in whole megawatts, which the Company has agreed to schedule over its transmission system from a specified POR to a specified POD pursuant to Opinion No. 318.

c) <u>Integrated Service Area</u>: A geographic area of the Company's system within which it is generally unconstrained in its ability to respond to requests to transmit power in the quantities that can be reasonably expected. A list of the existing Integrated Service Areas follows. This list is subject to revision based upon changes to the physical capabilities and contractual limitations under which the Company operates its transmission system.

1. The Company's Utah Power & Light Company (UP&L) service area in the state of Utah;
2. The Company's UP&L service area in the state of Idaho;
3. The Company's UP&L service area in the state of Wyoming;
4. The Company's Pacific Power & Light Company (PP&L) service area in Southern Oregon and Northern California;
5. The Company's PP&L Coos Bay, Oregon service area;
6. The Company's PP&L Lincoln City, Oregon service area;
7. The Company's PP&L Willamette Valley, Oregon service area;
8. The Company's PP&L Central Oregon service area;
9. The Company's PP&L Hood River, Oregon service area;
10. The Company's PP&L Portland, Oregon service area;
11. The Company's PP&L Clatsop, Oregon service area;
12. The Company's PP&L Enterprise, Oregon service area;
13. The Company's PP&L Pendleton, Oregon service area;
14. The Company's PP&L Walla Walla, Washington service area;
15. The Company's PP&L Yakima, Washington service area;
16. The Company's PP&L Sandpoint, Idaho service area;
17. The Company's PP&L Libby, Montana service area;
18. The Company's PP&L Kalispell, Montana service area;
19. The Company's PP&L service area in the state of Wyoming;

d) <u>Native Load</u>: Those customers of the Company receiving service under retail tariffs or special contracts under state regulatory jurisdiction.

e) Point of Delivery (POD): A point(s) of interconnection on the Company's transmission system between the Company and the receiving party or the receiving party's authorized agent where power and energy to be transmitted by the Company will be made available to such receiving party. The POD shall be specified in the Service Agreement.

f) Point of Receipt (POR): A point(s) of interconnection on the Company's transmission system between the Company and the delivering party or the delivering party's authorized agent where power and energy to be transmitted by the Company will be made available to the Company by such delivering party. The POR shall be specified in the Service Agreement.

g) Prudent Utility Practice: Shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry, or any practices, methods and acts which, in the exercise of reasonable judgement in the light of the facts known at the time, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety, and expedition and the requirements of governmental agencies having jurisdiction. Prudent Utility Practices are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a range of possible practices, methods or acts.

h) Qualifying Entity (QE): An eligible Tier 1, Tier 2 or Tier 3 Utility that files with the Company, during the Tier reservation periods established in Opinion No. 318, an executed contract for which firm transmission service on the Company's transmission system is desired. Such filed contract must contain sufficient information to enable the Company to ascertain the specific POD and POR, the Contract Demand which the Company will be expected to accommodate, and the required starting date and duration of the transmission service.

i) Remaining Existing Capacity (REC): The amount of firm transmission capability that the Company has announced is available for firm transmission service pursuant to Opinion No. 318 from specified PORs to specified PODs.

j) Transmission Dependent Utilities (TDU): Those utilities that are dependent on the Company for transmission access to their load or resources, including Deseret Generation and Transmission Cooperative, Utah Associated Municipal Power Systems, Inc. and its present members, and the present members of the Utah Municipal Power Association. As used in this definition, present members shall mean those entities that were members of the above referenced organizations on October 26, 1988.

INDEX OF UTILITIES EXECUTING
SERVICE AGREEMENTS

Customers	Service Schedule Number	Date of Execution	Effective Date

SERVICE SCHEDULE TS-1

FIRM TRANSMISSION SERVICE DURING THE FIVE YEAR TRANSITION PERIOD USING REMAINING EXISTING CAPACITY

AVAILABILITY

Transmission service under this Service Schedule TS-1 (Schedule) is available for a five year period commencing on the Announcement Date to: 1) Qualifying Entities (QE´s) which desire firm transmission service utilizing the portion of the Company´s Remaining Existing Capacity (REC) available to such QE´s Tier category as described below, and 2) other utilities which desire firm transmission service pursuant to the Company´s Wheeling Policy utilizing the portion of the Company´s REC which has not been allocated to QE´s. All transmission service to be provided by the Company under this Schedule shall be from a specific POR to a specific POD as specified in the Service Agreement. Firm transmission service available to QE´s shall be limited to the amount of REC available at the specified POD for use by QE´s in the following Tier categories:

Tier 1: Twenty percent of the REC shall be reserved for use by Transmission Dependent Utilities (TDU´s) that become QE´s. Such amount of REC shall be allocated to such QE´s during the allocation procedure described below after which any excess Tier 1 REC will be available on a first-come-first-served basis to such QE´s for the remainder of a one year period commencing on the Announcement Date.

Tier 2: Thirty percent of the REC shall be reserved for use by the following utilities which become QE´s:

Idaho Power Company
The Montana Power Company
Black Hills Power & Light Company
Western Area Power Administration
Basin Electric Power Cooperative, Inc.
Tri-State Generation and Transmission Cooperative, Inc.

Such amount of REC shall be allocated to such QE´s during the allocation procedure described below after which any excess Tier 2 REC will be available on a first-come-first-served basis to such QE´s for the remainder of a one year period commencing on the Announcement Date.

<u>Tier 3</u>: Fifty percent of the REC shall be reserved for use by any electric utility, including the Company, that becomes a QE. Such amount of REC shall be allocated to such QE´s pursuant to the allocation procedure described below.

<u>ALLOCATION PROCEDURE</u>:

If at the end of a 90-day period commencing with the Announcement Date, QE requests for firm transmission service at a particular POD exceed the REC available at such POD in any Tier category, the REC available for such Tier category will be allocated to the requesting QE´s in such Tier category in proportion to the Contract Demand specified in the QE´s underlying contract(s) which were filed with the Company to achieve QE status.

In the event that QE requests for firm transmission service to specified PODs exceed the REC available elsewhere in the Company´s system, then the REC available from all specified PORs to all specified POD´s for any Tier category will be reduced as required by the limiting REC and then allocated to the requesting QE´s in such Tier category in proportion to the Contract Demand specified in the QE´s underlying contract(s) which were filed with the Company to achieve QE status.

UNALLOCATED CAPACITY:

Any Tier 3 REC that has not been allocated or subscribed at the end of the 90-day period commencing with the Announcement Date, shall be made available for firm transmission service pursuant to the terms of the Company's Wheeling Policy.

Any Tier 1 or Tier 2 REC that has not been allocated or subscribed at the end of a one year period commencing with the Announcement Date, shall be made available for firm transmission service pursuant to the terms of the Company's Wheeling Policy.

COMPANY WHEELING POLICY:

All REC not allocated to QE's as set forth above, shall be made available to requesting electric utilities under the following terms:

A. Determination of Ability to Provide Service

When either or both the Point of Receipt or Delivery are not internal to a single Integrated Service Area, the Company will provide firm wheeling service to a requesting Utility unless the Company determines that provision of the requested service would impair its ability to render service to Native Load customers, would preclude its ability to meet obligations under previously executed wheeling and bulk power contracts, or would otherwise be impractical or impermissible for reasons beyond the Company's control. This determination will be based upon a reasonable, case-specific evaluation of the following factors only:

1. The duration of the requested service;

2. Whether new facilities would have to be constructed in order to provide the requested service over the Company's facilities;

3. Whether other utilities desire the same transmission services;

4. Whether the provisions of transmission contracts with other utilities permit the requested service;

5. Whether the intentions of the Utility requesting service are lawful (for example would there be a violation of laws related to a certificated area);

6. The degree of firmness of the requested service;

7. The service priority of the requested service;

8. The system impacts of the requested service;

9. To the extent the requested service involves the control area of another utility, whether that other utility will cooperate in providing the service;

10. Whether the Utility requesting service is a scheduling utility; and

11. Current laws and regulations as they apply to the Company and its competitors.

B. <u>Reciprocity</u>

A Utility requesting firm wheeling service under this policy may not unreasonably deny the Company comparable service over comparable facilities controlled by the requesting Utility.

C. <u>Other Restrictions</u>

The Company shall not withhold transmission capacity for which firm transmission is requested in order to effect a purchase and resale of bulk power.

CHARACTER OF SERVICE

Unless otherwise specified in the Service Agreement, all transmission service under this Schedule shall be three-phase, 60 Hertz alternating current utilizing available transmission voltages of the Company.

PRICING:

The annual charge for all firm transmission service provided under this Schedule shall be the applicable cost based annual rate ($ per KW) multiplied by the maximum Contract Demand (KW) specified in the Service Agreement and payable in monthly installments equal to 1/12 of such annual charge for the term of the Service Agreement. In the case of Tier 1 and 2 QE´s, such applicable annual rate ($/KW) shall be based on the embedded cost of the Company´s operating division providing such service. In the case of Tier 3 QE´s, and for service provided under the Company´s Wheeling Policy, such applicable annual rate ($/KW) shall be cost based, but not limited to embedded cost, pursuant to a methodology to be proposed by the Company as part of its Section 205 filing subsequent to the allocation procedure described above.

In the case of transmission service provided to Tier 1 QE´s or to Tier 2 or 3 QE´s who desire transmission service to a Transmission Dependent Utility (TDU), the Company will consider the suitability of a less flexible class of service, which will be addressed as part of its Section 205 filing. The factors to be considered in assessing the suitability and the proposed annual charge methodology for such a less flexible class of service will include: 1) whether the REC associated with a particular Tier category is fully subscribed; 2) whether the Company is able to retain the use of its transmission system which is not required to meet the hourly schedules of power and energy for the TDU´s actual native load requirements; and 3) whether the deliveries under such less flexible class of service is limited to the TDU's Points of Delivery from which such TDU's native load is directly served.

In the event that the FERC authorizes the Company to commence service under this Schedule prior to the final disposition of its Section 205 filing, the Company is prepared to commence such services at negotiated rates subject to refund pending such final disposition.

LOSSES:

Utilities receiving transmission service under this schedule shall compensate the Company for losses associated with the provision of such service. Such compensation shall be scheduled to the Company pursuant to the terms of the Service Agreement.

SERVICE AGREEMENTS:

Except for Service Agreements with Tier 1 or Tier 2 QE's, all Service Agreements under this Schedule shall have a term of not less than one year and not greater than five years from the Announcement Date. Any Service Agreements with Tier 1 or Tier 2 QE's shall have a term equal to the term of the underlying contract(s) giving rise to their QE status, provided that after five years from the Announcement Date, such Service Agreements shall be deemed to be Service Agreements under Service Schedule TS-4 of this Tariff for the purpose of pricing of transmission services.

Except as provided for Tier 1 and Tier 2 QE's, any entity receiving service under this Schedule which desires firm transmission service after five years from the Announcement Date shall be required to execute a Service Agreement under Service Schedule TS-4 of this Tariff.

GENERAL TERMS AND CONDITIONS

All transmission service under this Schedule shall be in general accordance with the terms of a Service Agreement of the form attached to this Schedule. The general terms and conditions of the Tariff and this Schedule, including future applicable amendments, will be considered as forming a part of and incorporated in the Service Agreement.

SERVICE SCHEDULE TS-2

FIRM SERVICE WITHIN AN INTEGRATED SERVICE AREA

AVAILABILITY

This Service Schedule TS-2 (Schedule) is available for a five year period commencing with the Announcement Date to electric utilities which request firm transmission service from the Company where both the Point of Receipt (POR) and the Point of Delivery (POD) are located within the boundaries of an Integrated Service Area. Transmission service shall be available unless the amount of power to be transmitted exceeds the engineering limitations of the Company's transmission facilities within the Integrated Service Area. When evaluation of the requested service results in the identification of a need for new transmission facilities, the Company will construct additions to its transmission facilities to accommodate the request where such additions are technically feasible, where sufficient lead time is provided to the Company to construct the needed facilities, and pursuant to the terms of a Participation Agreement under Service Schedule TS-3.

CHARACTER OF SERVICE

Unless otherwise specified in the Service Agreement, all transmission service under this Schedule shall be three-phase, 60 hertz alternating current utilizing available transmission voltages.

PRICING:

Rates for service under this Schedule shall be established in a filing with the Federal Energy Regulatory Commission (FERC) under Section 205 of the Federal Power Act (FPA).

LOSSES:

Utilities receiving transmission service under this Schedule shall compensate the Company for losses associated with the provision of such service. Such compensation shall be scheduled to the Company pursuant to the terms of the Service Agreement.

CONTRACT PERIOD:

The minimum contract period shall be one year.

GENERAL TERMS AND CONDITIONS

All transmission service under this Schedule shall be in general accordance with the terms of a Service Agreement of the form attached to this Schedule. The general terms and conditions of the Tariff and this Schedule, including future applicable amendments, will be considered as forming a part of and incorporated in the Service Agreement.

SERVICE SCHEDULE TS-3

PARTICIPATION BY OTHER UTILITIES IN TRANSMISSION CONSTRUCTION

AVAILABILITY

This Service Schedule TS-3 (Schedule) is available to eligible utilities, as described below, that desire to participate in a Company initiated transmission capacity addition project, or that desire to initiate an upgrade, improvement, or addition to the Company's facilities within an Integrated Service Area subject to the conditions enumerated below. Such utilities shall execute a Transmission Participation Agreement (Participation Agreement) prior to the end of a five year period commencing with the Announcement Date and prior to the commencement of construction of any project for which such participation is desired.

<u>All Utilities</u>: Where the Company initiates construction of transmission facilities of voltage levels of 345 kV or higher, it shall afford other utilities the opportunity to participate in the project, subject to state regulatory approval, provided that:

(a) the potential participants have a legitimate interest or service-related purpose in such participation, and

(b) the joint participation will not unreasonably delay the project or render it impractical for the Company as a matter of economics or engineering, and

(c) the potential participants are prepared to equitably share in the costs and benefits of the project considering the cost of the project, the value of the Company's existing investment in related facilities and the benefits to be derived by each party, and

(d) the utility requesting the opportunity to participate has not unreasonably denied the Company's participation in comparable projects.

Transmission Dependent Utilities (TDU): Where the Company initiates a transmission capacity expansion, it shall agree to joint participation in upgrades, improvements or additions to its backbone transmission (138 kV or higher), interconnections and substation facilities of the operating division of the Company that serves a TDU so that such a TDU may, subject to state regulatory approval, reasonably participate in the expansion project, provided that:

(a) the potential participants have a legitimate interest or service-related purpose in such participation, and

(b) the joint participation will not unreasonably delay the project or render it impractical for the Company as a matter of economics or engineering, and

(c) the potential participants are prepared to equitably share in the costs and benefits of the project considering the cost of the project, the value of the Company's existing investment in related facilities and the benefits to be derived by each party.

When requested by a TDU, the Company shall not unreasonably withhold its consent for upgrades, improvements or additions to its interconnections, transmission and substation facilities located within an Integrated Service Area, and subject to applicable state regulatory approval, provided that:

(a) the requesting TDU pays for the upgrades, improvements or additions, and

(b) the upgrades, improvements or additions are required to serve the retail or wholesale customers of the TDU, and

(c) the upgrades, improvements or additions are consistent with the Company's engineering and construction standards, and

(d) the parties are able to agree upon a fair allocation among them, or in the absence of such agreement, the requesting utility is prepared to equitably allocate the additional resulting transfer capability considering the cost of the project and the value of the Company's existing investment in related facilities.

GENERAL TERMS AND CONDITIONS

Service under this Schedule will be in accordance with the terms of the Participation Agreement between the Company and the participant(s). The General Terms and Conditions of the Tariff and this Schedule, including future applicable amendments, will be considered as forming a part of and incorporated in the Participation Agreement.

Prior to the execution of a Participation Agreement, such participant shall obtain an authorizing resolution from its Board of Directors and be required to provide sufficient project construction security in the form of cash, performance bonds, letter of credit, corporate pledge of assets or any other instrument acceptable to the Company. Such instruments of security shall be provided to the Company at the time the Participation Agreement is executed.

SCHEDULE TS-4

**LONG TERM FIRM
TRANSMISSION SERVICE**

AVAILABILITY

Firm transmission service under this Service Schedule TS-4 (Schedule) will be available as of the Announcement Date to any electric utility requesting transmission service from the Company that executes a Service Agreement except where providing the requested service would interfere with or disrupt the Company's Tier 1 or Tier 2 transmission obligations which were incurred under Service Schedule TS-1 or would jeopardize the safe, economic and reliable operation of the Company's service to its Native Load customers or its wholesale customers under firm contracts entered into prior to August 12, 1987.

The Company will make reasonable efforts to meet all bona fide requests for firm transmission service which are consistent with the limitations set forth in the preceeding paragraph, as soon as practicable but in no event, more than five years from the date specified in the Service Agreement or other mutually agreeable time, by using the Company's then existing transmission capacity or in the event that the Company, in its judgement, determines that such existing transmission capacity is not available or is not sufficient, by the construction of new transmission facilities. In the event that the Company, in its judgement, determines that the construction of new transmission facilities is required, the requesting utility shall cooperate with the Company in facilitating such construction and shall take all reasonable steps to assist the Company in obtaining any necessary permits and right-of-way. Unless otherwise specified in the Service Agreement, the Company shall own, operate and control such new facilities and shall design such new facilities with appropriate consultation with the requesting utility and considering the planning needs of the Company, the amount and duration of the transmission service requested and the efficient use of the Company's existing system.

In the event that the Company is unable to complete such new facilities within five years, the requesting utility may cause the Company to displace its own wholesale sales transactions entered into subsequent to August 12, 1987, pursuant to Opinion No. 318, if such displacement would allow the requested firm transmission service to be provided by the Company.

CHARACTER OF SERVICE

This Schedule is applicable to all utilities pursuant to the terms of the Service Agreement for transmission of power and energy between a specified Point of Receipt and a specified Point of Delivery on the Company's transmission system at available transmission voltages.

PRICING:

The rates for transmission service rendered under this Schedule shall be based upon the full cost of providing the requested service, not limited to the Company's embedded cost. Where the Company determines that it will provide the requested service by the construction of new facilities, the requesting party must, at the time the Service Agreement is executed:

(a) contract to pay the full cost of the facilities to be constructed, and

(b) proffer sufficient security such that the Company will not be at financial risk due to non-performance by the requesting utility. Such security shall be in the form of cash, performance bond, irrevocable letter of credit, corporate pledge of assets, or any other instrument of security acceptable to the Company.

Initial rates for service under this Schedule shall be established in a filing with the Federal Energy Regulatory Commission under Section 205 of the Federal Power Act.

LOSSES:

Utilities receiving transmission service under this Schedule shall compensate the Company for losses associated with the provision of such service. Such compensation shall be scheduled to the Company pursuant to the terms of the Service Agreement.

CONTRACT PERIOD:

The contract term shall be specified in the Service Agreement. Where new facilities are constructed to meet a request, the contract term shall be for a period which is adequate to economically support the cost of the facilities required.

GENERAL TERMS AND CONDITIONS

Service under this Schedule will be in accordance with the terms of the Service Agreement between the Utility and the Company. The general terms and conditions of the Tariff and this Schedule, including future applicable amendments, will be considered as forming a part of and incorporated in the Service Agreement.

SERVICE SCHEDULE TS-5

NON-FIRM TRANSMISSION SERVICE

AVAILABILITY

This Service Schedule TS-5 (Schedule) is available to any electric utility for the transmission of non-firm energy at transmission voltages either directly with the Company or through the Western Systems Power Pool. A Service Agreement generally of the form attached to this Schedule shall be executed prior to any transactions. The Company will enter into transactions at its sole discretion to the extent that it determines that transmission capacity is available for transmitting non-firm power by scheduling electric utilities. Such determination by the Company shall be made in view of its obligation to provide safe, economic and reliable service to its Native Load customers, its firm wholesale customers and its firm transmission service customers.

CHARACTER OF SERVICE

This Schedule is applicable to all utilities as specified above for transmission of non-firm energy between a specified Point of Receipt and a specified Point of Delivery on the Company's transmission system at transmission voltages.

PRICING:

The rate for transmission service under this Schedule shall be equal to one-third of the difference between the Incremental Cost of the Seller and the Decremental Cost of the Buyer, for all non-firm energy transmitted under this Schedule.

SCHEDULING:

To the extent that the Company determines that transmission capacity is available, the Buyer or Seller will schedule with the Company between a specified Point(s) of Receipt (POR) and a specified Point(s) of Delivery (POD). Schedules will be accepted only in whole megawatts, and accounting for all service will be based upon scheduled quantities. Schedules are subject to interruption as determined by the Company at its sole and absolute discretion at any time.

LOSSES:

Utilities receiving transmission service under this Schedule shall compensate the Company for losses associated with the provision of such service. Such losses shall be based on the Company's divisional system average annual losses, unless the Company determines through studies that actual losses associated with the transmission service provided hereunder are greater than 120 percent of such system average losses, in which case losses will be determined on an incremental basis. Unless otherwise mutually agreed, losses shall be scheduled to the Company at the POR, concurrently with the scheduled delivery of non-firm energy to be transmitted by the Company.

DEFINITIONS

a) Incremental Cost of Seller: The actual increase in energy cost incurred by the Seller to provide the energy to be transmitted to the Buyer. The Company shall have the right to request verification of the actual energy cost by examination of the Seller's operational logs and cost information to be supplied to the Company by the Seller. In the event that such data are not available, the Incremental Cost of Seller shall be deemed to be equal to the average variable cost of the lowest cost resource of the Seller as shown in the most current FERC Form No. 1 or equivalent annual report. Opportunity cost shall not be acceptable for determination of incremental cost.

b) <u>Decremental Cost of Buyer</u>: The energy cost avoided by the Buyer in order to accept energy to be transmitted under this Schedule. The Company shall have the right to request verification of the actual energy cost by examination of the Buyer's operational logs and cost information to be supplied to the Company by the Buyer. In the event that such data are not available, the Decremental Cost of Buyer shall be deemed to be equal to the average variable cost of the highest cost resource of the Buyer as shown in the most current FERC Form No. 1 or equivalent annual report.

GENERAL TERMS AND CONDITIONS

Service under this Schedule will be in accordance with the terms of the Service Agreement between the Purchaser and the Company. The general terms and conditions of the Tariff and this Schedule, including future applicable amendments, will be considered as forming a part of and incorporated in the Service Agreement.

FORM OF TRANSMISSION SERVICE AGREEMENT

(Non-firm Services)

UTILITY:

ADDRESS OF CUSTOMER:

SERVICE: For nonfirm transmission services under the terms and conditions of PacifiCorp's FERC Electric Tariff, Original Volume No. 5, Service Schedule TS-5 (Tariff), Non-firm Transmission Service.

QUANTITIES: As agreed between the Purchaser and the Company at the time the transaction is scheduled.

POINT OF RECEIPT (POR) AND POINT OF DELIVERY (POD): The POR and POD shall be agreed between Utility and Company at the time the service under this Agreement is requested.

APPLICABLE RATE AND CONDITIONS: As determined pursuant to the terms and conditions of the Tariff.

TERM: This Agreement may be terminated by either party on thirty days written notice, except that liability for payment shall continue until paid.

EFFECTIVE DATE: ________________, subject to acceptance for filing by the Federal Energy Regulatory Commission.

CONTINUITY OF SERVICE: Transmission service under TS-5 is non-firm and Company, in its sole and absolute discretion, may curtail or interrupt service without cost or liability at any time.

SPECIAL CONDITIONS: (Applicable only if third party wheeling is required to complete a transaction.) (Purchaser/Seller) designates and authorizes ________________ to act in its behalf as transferring and/or receiving agent (Agent) for all non-firm energy scheduled by Company to such Agent for Customers account. Utility shall be responsible for all transfer and ultimate delivery arrangements, including transfer charges and losses incurred beyond Company's point(s) of interconnection with Agent. Utility shall, in advance, schedule, or cause to be scheduled, all deliveries or receipts of energy between Company and Agent for Customer's account. Company shall accept such scheduled deliveries from Agent at the POR, or shall make such schedule deliveries available to Agent at the POR and Customer shall pay Company for all such scheduled deliveries.

The parties hereto have agreed to the foregoing dates, terms, and conditions as of the ________ day of ________________, 19 ____.

PACIFICORP

By ______________________________
Title

By ______________________________
Title

Exhibit C

Generic Service Agreement
for
Service Schedules TS-1 and TS-2

GENERIC
FIRM TRANSMISSION SERVICES AGREEMENT

BETWEEN

PACIFICORP

and

____

This document is intended to provide the minimum contract provisions for firm transmission service under Service Schedules TS-1 and TS-2 and therefore, may not contain provisions which cover every circumstance. Unforeseen circumstances will be addressed in a specific agreement for each electric utility requesting firm transmission service pursuant to the Company's FERC Electric Tariff, Original Volume No. 5.

FIRM
TRANSMISSION SERVICE AGREEMENT

between

PACIFICORP, DOING BUSINESS AS ____________________

and

______ Utility ______

This FIRM TRANSMISSION SERVICE AGREEMENT executed this _____ day of _____________, 19___ by and among PacifiCorp, an Oregon corporation, doing business as _________________ ("Company") and **Utility**, which hereinafter collectively may be referred to as "Parties" or individually referred to as "Party".

W I T N E S S E T H

WHEREAS, the Parties are engaged in the sale of electric power and energy, and are interconnected with each other and/or with other electric utility systems; and

WHEREAS, the Federal Energy Regulatory Commission (FERC) under Opinion No. 318 in Docket No. EC88-2-000 (Opinion No. 318) established certain requirements and procedures governing the Company's provision of firm transmission service to other utilities; and

WHEREAS, **Utility** is a Qualifying Entity or a qualifying utility under Opinion No. 318 and has requested firm transmission service from the Company pursuant to Opinion No. 318; and

WHEREAS, the Company has determined that it is willing to provide the requested firm transmission service pursuant to Opinion No. 318 as set forth in the terms and conditions of PacifiCorp's FERC Electric Tariff, Original Volume No. 5 ("Tariff"), and the terms of this Service Agreement ("Agreement").

NOW THEREFORE, in consideration of mutual benefits to the Parties, the Parties agree as follows:

Section 1 - Definitions

As used herein, the following terms have the following meanings when used with initial capitalization whether singular or plural;

1.1 Control Area: Shall mean an electric system capable of regulating its generation in order to maintain its interchange schedule with other electric systems and to contribute its frequency bias obligation to the interconnection as specified in the North American Reliability Council (NERC) Operating Guidelines.

1.2 Effective Date: Shall mean the date determined in paragraph 2.1 of this Agreement.

1.3 Point of Delivery (POD): Shall have the meaning set forth in the Tariff and for the purposes of this Agreement such POD(s) shall be ______________.

1.4 Point of Receipt (POR): Shall have the meaning set forth in the Tariff and for the purposes of this Agreement such POR(s) shall be ______________.

1.5 Contract Demand: Shall have the meaning set forth in the Tariff and for the purposes of this Agreement, such Contract Demand shall be _____ MW, which amount is consistent with the contractual obligations in Exhibit 1.

Section 2 - Term and Regulatory Filing

2.1 Effective Date and Filing: This Agreement shall be effective on _______________ or such other date as may be designated by the FERC when accepted for filing. The Company shall file this Agreement with the FERC as a Service Agreement under Service Schedule _____ of the Tariff.

2.2 Cancellation Rights: If FERC or any regulatory agency having authority over this Agreement determines that any part of this Agreement must be changed, any Party adversely affected by such change(s) shall have the right to cancel this Agreement upon 30 days written notice to the other Party, or alternatively and in the adversely affected Party's sole discretion, to reopen negotiations in order to attempt to restore the balance of consideration contained in the Agreement as originally executed.

2.3 Termination of Agreement: Except as provided in paragraph 2.2, this Agreement shall remain in effect until ____________.

Section 3 - Transmission Services

3.1 Services to be Provided: Commencing on the Effective Date, the Company shall accept schedules of power and energy from **Utility** or its authorized agent at the POR in amounts not to exceed the Contract Demand, and shall simultaneously schedule such amounts of power and energy, less transmission losses, for delivery to **Utility** or its authorized agent at the POD. The Company's obligation to schedule such amounts of power and energy shall be subject to the Company's right to curtail or interrupt such schedules pursuant to Sections 3.2 and 3.3 below.

3.2 Limitations of Transmission Capability: (Service Schedule TS-1 only). The Parties understand and agree that the firm transmission service provided under this Agreement results from an allocation of the Company's Remaining Existing Capacity (REC) as that term is defined in the Tariff. The Parties further understand and agree that if, despite the Company's best efforts to determine and allocate such REC, competing services under the Tariff exceed the Company's transmission capability in any hour, and to the extent such exceedence limits the Company's ability to provide such transmission service under this Agreement for such hour, then the Company shall reduce the Contract Demands of all such competing services proportionately for such hour as necessary to maintain reliable service to its firm and interruptible native load customers and customers under firm contracts pursuant to Opinion No. 318.

3.3 Continuity of Service: The Company shall make reasonable provisions to supply continuous firm transmission service, but does not guarantee that such service will be uninterrupted for reasons including, but not limited to: 1) interruptions or reductions due to a force majeure pursuant to Section 8; 2) interruptions or reductions due to action instituted by automatic or manual controls for the purpose of maintaining overall reliability and continuity of the Company's transmission system or generation facilities; 3) interruptions or reductions which, in the opinion of the Company's operating personnel, are necessary for the purposes of maintenance, repairs, replacements, installation of equipment or inspections of the Company's generation and/or transmission facilities; or 4) interruptions or reductions necessary in order to maintain reliable service to the Company's firm and interruptible native load customers and firm wholesale customers pursuant to Opinion No. 318.

Section 4 - Other Services

(Applicable to TDUs only)

4.1 Load Following Service: Load following service is not provided under this Agreement. If **Utility** is located within or is providing power and energy for loads within a Control Area of the Company and has no other agreement with the Company for the provision of such service, as may be required by this Agreement, the Company is willing to negotiate the provision of such load following service.

4.2 Back-up and Reserve Requirements: This Agreement does not provide for back-up service. In the event that service under this Agreement is curtailed or interrupted, it shall be the responsibility of **Utility** to arrange for a replacement resource within ten (10) minutes, or to curtail load to restore its load/resource balance. In the event of such curtailment or interruption, **Utility** shall return all power and energy supplied by the Company within 24 hours or as otherwise mutually agreed. The Company is willing to negotiate the provision of such back-up service.

4.3 Accounting and Dispatching Services: The Company shall provide the necessary accounting and dispatching services required by this Agreement. **Utility** shall compensate the Company for the incremental costs including but not limited to manpower and computer facilities associated with such services. If such compensation has already been established under another agreement with the Company, any additional compensation required under this Agreement shall be in accordance with the terms of such agreement.

Section 5 - Scheduling Provisions

5.1 All Transmission Services to be Scheduled: All amounts of power and energy to be transmitted under this Agreement shall be scheduled in accordance with this Section 5, and to the extent not specifically set forth in this Section, in accordance with normally accepted scheduling practices. All schedules across Control Area boundaries shall be to the nearest whole megawatt.

5.2 Preschedules: By 1300 hours, Pacific time, on the last work day observed by the Company prior to the date of any transfers under this Agreement, **Utility** shall provide or cause to be provided to the Company at its ______________ control center, a preschedule of transfers for each hour of each of the following day or days.

5.3 Modification of Preschedules: In the event that unforeseen circumstances require that preschedules for any hour be modified, **Utility** may revise such preschedules up to 30 minutes prior to such hour and unless so modified, such preschedule shall be the actual schedule for such hour.

Section 6 - Loss Provisions

6.1 Transmission Losses: **Utility** shall reimburse the Company for transmission losses incidental to all scheduled deliveries of power and energy hereunder. Such losses shall be based on the Company's appropriate divisional annual average transmission losses, unless the Company determines through studies that the actual losses associated with the transmission service to be provided hereunder are greater than 120 percent of such division's annual average losses, in which case such losses will be determined on an incremental basis.

6.2 Replacement of Losses: Unless otherwise mutually agreed, **Utility** shall deliver losses to the Company at the Point of Receipt concurrently with the scheduled delivery of power and energy to be transmitted by the Company.

Section 7 - Charges and Payments

7.1 Charges for Transmission Service: **Utility** shall compensate the Company for transmission services hereunder at the then effective rate(s) applicable to the Service Schedule specified in Section 2.1.

7.2 Billing and Payment: Bills for all services provided under this Agreement shall be rendered monthly by the Company and all such bills shall be due and payable within 15 calendar days from the date of mailing as determined by postmark. Any amounts due and unpaid after the due date shall be termed delinquent and interest shall be added to such delinquent amount at the rate of 0.0411 percent per day (15 percent per year) until received by the Company.

7.3 Disputed Bills: In event of a disputed bill, payment of the entire billed amount shall be made within the 15-day period provided in paragraph 7.2, provided that the disputed portion of the bill may be paid under protest. Payments made and designated as disputed shall be accompanied by a written description of the reasons therefore. Any refunds resulting from the settlement of such disputed amounts will include interest at the rate specified in Section 7.2 above during the pendency of such dispute.

Section 8 - Force Majeure

Neither Party to this Agreement shall be considered in default in performance of any obligation hereunder if failure of performance shall be due to force majeure. The term "force majeure" means any cause beyond the control of the Party affected, including, but not limited to, failure of facilities, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, labor dispute, sabotage and action by court order or public authority which by exercise of due foresight such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to overcome. A Party shall not, however, be relieved of liability for failure of performance if such failure is due to causes arising out of its own negligence or to removable or remediable causes which it fails to remove or remedy with reasonable dispatch. Any Party rendered unable to fulfill any obligation by reason of force majeure shall exercise due diligence to remove such inability with all reasonable dispatch. Nothing contained herein, however, shall be construed to require a Party to prevent or settle a labor dispute against its will.

Section 9 - Indemnification

Except as provided in this Section 9.1, each Party hereto hereby assumes all liability for injury or damage to persons or property arising from the act or neglect of its own employees, agents or contractors and shall indemnify and hold the other harmless from any liability arising therefrom. Notwithstanding the foregoing, no Party ("First Party") shall be liable, whether in contract warranty, tort or strict liability, to the other Party ("Second Party") for any injury or death to any person, or for any loss or damage to any property, caused by or arising out of an electric disturbance on the First Party's electric system, whether or not such electric disturbance resulted from the First Party's negligent, grossly negligent or wrongful act or omission, excepting only action knowingly or intentionally taken, or failed to be taken, with intent that injury or damage result therefrom, or which action is wantonly reckless. Each Second Party releases the First Party from, and shall indemnify the First party for, any such liability. As used in this Section, (1) the term "Party" means, in addition to such Party itself, its directors, officers and employees; (2) the term "damage" means all damage, including consequential damage and (3) the term: "Person" means any person, including those not connected with either Party to this Agreement.

Section 10 - Miscellaneous Provisions

10.1 Transmission Services Only: This Agreement is only for the specific firm transmission services described herein. Such firm transmission service will be considered to create a transmission capacity entitlement or reservation on the Company's system, subject only to the ability of the Company to interrupt or curtail said transmission service as set forth in this Agreement.

10.2 No Guarantee of Absolute Firm Service: The Company does not warrant or guarantee that transmission services under this Agreement will be free from interruption or curtailment and the Company shall not be liable to **Utility** for any damages resulting from any such interruption or curtailment. The Company will provide **Utility** reasonable advance notice of any scheduled activities or conditions as set forth in Section 3.3 hereof that will result in interruptions or curtailments of services hereunder. The Company shall use due diligence to remove expeditiously all causes of interruptions or curtailments of transmission services which are under its control.

10.3 Interconnected Operations Agreement: **(Applicable to TDUs only.)** Those electric utilities having a Point of Delivery within the Company's Control Area(s) shall be required to have an Interconnected Operations Agreement in place prior to commencement of transmission service hereunder.

10.4 Future Changes or Additions: Future changes or additions which increase the Company's transmission system capability shall not obligate the Company to provide any transmission or other services in addition to those services provided herein.

10.5 Regulatory Jurisdiction: The provisions of this Agreement are subject to such regulatory agencies having jurisdiction thereof. Nothing contained herein shall be construed as affecting in any way the right of the Company to unilaterally make application to the FERC for a change in rate, charges, classification of service, or any rule, regulation or service agreement related thereto, under Section 205 of the Federal Power Act or any successor statute and pursuant to the Commission's Rules and Regulations formulated thereunder.

10.6 Applicable Laws: The Parties in their performance of their obligations hereunder shall conform to all applicable laws, rules and regulations and, to the extent their operations are subject to the jurisdiction of state or federal regulatory agencies, they shall be subject to the terms of valid and applicable orders of such agencies. This Agreement shall be construed in accordance with the laws of the state of Oregon.

10.7 Waivers: Any waiver at any time by either Party hereto of its rights with respect to the other Party or with respect to any matter arising in connection with this Agreement shall not be considered a waiver with respect to any subsequent default of such matter.

10.8 Successors and Assigns: This Agreement shall inure to the benefit of, and be binding upon, the Parties and their respective successors and assigns, and may be assigned by either Party without prior written consent of the other Party, provided that in the event of such assignment, the assigning Party shall continue to have primary responsibility for the payment and operating obligations and responsibilities set forth in the Agreement unless relieved of such primary responsibility by written consent of the other Party. Such written consent shall not be unreasonably withheld.

10.9 Effect of Section Headings: Section headings appearing in this Agreement are inserted for convenience of reference only and shall not be construed to be interpretations of the text of this Agreement.

10.10 Remedies Not Exclusive: The specification of a remedy in any section or paragraph of this Agreement for failure of a Party to meet any of its obligations shall not be deemed to affect or limit the right of any Party to seek any such other legal, equitable or administrative remedies as may be available for such failure.

10.11 Complete Agreement: This Agreement is intended as the exclusive, integrated statement of the Parties' agreement regarding all of the services provided hereunder. Parol or extrinsic evidence shall not be used to vary or contradict the express terms of this Agreement.

10.12 <u>Notices</u>: Any written notices to be given to the Company under this Agreement shall be directed to:

____________________, Vice President

____

____

____

Any written notices to be given to __________________________ under this agreement shall be directed to:

____

____

____

____

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names by their duly authorized officers as of the date first above written.

PACIFICORP, doing business as ____________________

By: ________________________ Title: ________________________

ATTEST:

By: ________________________ Title: ________________________

(Corporate Seal)

By: ________________________ Title: ________________________

ATTEST:

By: ________________________ Title: ________________________

(Corporate Seal)

EXHIBIT 1

Contract for firm capacity and energy filed with the Company to obtain Qualifying Entity Status pursuant to FERC Opinion No. 318.

EXHIBIT 2

Company

FERC Electric Tariff

Original Volume No. 5

Exhibit D

Pricing of Transmission Services

PRICING OF WHEELING SERVICE

A. General Pricing Considerations

For the five year transition period, Opinion No. 318 provided for the use of embedded cost rates for Tiers 1 and 2. Rates based upon cost, but not necessarily limited to embedded cost, were authorized for Tier 3.[1/] Illustrative rates for the respective tiers are provided as guidance to prospective wheeling customers who may consider making an application for an allocation of the Company's Remaining Existing Capacity (REC).

These preliminary prices are intended as examples only. Final rates will be determined by the Commission upon disposition of the Company's forthcoming filing under Section 205 of the Federal Power Act (FPA) as directed by the Commission's Order.[2/]

Further, the Company is willing to initiate transmission service prior to the effective date of rates that will be established under the Section 205 filing required by Opinion No. 318. Initial rates for transmission service during the interim period will be based upon individual negotiations with the prospective customers with all revenues being subject to adjustment to the effective date of first service in accordance with pricing results from the pending 205 filing.

For transmission service subsequent to the five-year transition period, long-term pricing will be based upon costs, not limited to embedded costs, and set consistently with FERC's then prevailing general transmission policies.

Opinion No. 318 establishes that contracts for capacity obtained under the allocation of the REC ". . . shall not contain any provision restraining whatever rights exist under the FPA to re-sell or re-assign that capacity."[3/] Thus, the Company intends to offer blocks of capacity to utilities which become Qualifying Entities (QE), as defined in Opinion No. 318, based on the demands contained in contracts filed with the Company.

1/ Page 42, FERC Opinion No. 318
2/ Pages 42 and 60-61, FERC Opinion No. 318
3/ Page 43, FERC Opinion No. 318

Inherent in this provision--the right of a contracting party to re-assign capacity rights to a third party--is the necessity of applying Take-or-Pay pricing to the services rendered by the Company. Without such pricing, the QE would have unrestricted use of the Company's transmission capacity but escape the full cost burden associated with the capacity right obtained. Further, this pricing provides equitable treatment to the Company's native load customers and provides an incentive for such QEs to make maximum use of the capacity rights they obtain.

In the case of transmission service provided to Tier 1 QE's or to Tier 2 or 3 QE's who desire transmission service to a Transmission Dependent Utility (TDU), the Company will consider the suitability of a less flexible class of service, which will be addressed as part of its Section 205 filing. The factors to be considered in assessing the suitability and the proposed annual charge methodology for such a less flexible class of service will include: (1) whether the REC associated with a particular Tier category is fully subscribed, (2) whether the Company is able to retain the use of its transmission system which is not required to meet the hourly schedules of power and energy for the TDUs actual native load requirements, and (3) whether the deliveries under such less flexible class of service is limited to the TDU's points of delivery from which such TDU's native load is directly served.

B. Tier 1 and Tier 2 Pricing

The illustrative prices shown on page 6 of Exhibit D reflect estimated divisional pricing for the services to be obtained through Tier 1 and 2 allocation of REC. No prices have been provided for wheeling between the current Utah and Pacific systems because as shown in Exhibit A, Company integration requirements will require all available transmission capacity.

Listed below is a summary of the major assumptions utilized in calculating the illustrative range of prices shown on page 6 of Exhibit D. These assumptions are not presumptive, but have been made to simplify the filing as well as to provide reasonable consistency between the Company's two divisions.

1. A historical test period for the twelve months ended December 1987 was used with an end of period rate base.

2. Cost information within each Division has been consistently applied, through the use of the FERC Staff "Top Sheet" allocation model.

3. Transmission related accounts from the Uniform System of Accounts have been directly functionalized to produce a revenue requirement associated with transmission plant. Indirect and overhead related costs have been generally allocated on relative plant relationships.

4. A weighted rate of return range of 10.7 to 11.1 percent was used reflecting pro forma capital structure and component costs.

5. Fifty percent of transmission related construction work in progress has been included in rate base pursuant to the Code of Federal Regulations, 18 CFR, §35.26(c).

6. Income taxes have been computed based on the 1988 Federal tax rate of 34 percent and utilize tax normalization methodologies authorized by this Commission under Order No. 144 and 144-A.

7. Cash working capital has been determined using the formula methodology contained in FERC Opinion No. 19-A.

8. For the purpose of obtaining illustrative Take-or-Pay prices for capacity obtained through the REC allocation procedure, the revenue requirement was converted to an annual unit cost.

   First, a price level was estimated without additional transmission service. Demands utilized in the calculation were obtained by averaging the 1987 monthly coincidental peak loads for native load, wholesale customers, and existing firm transmission service. This results in an average coincidental peak load for use of the transmission system. This demand figure was divided into the transmission system revenue requirement to obtain the annual unit cost (page 6, line 19 of Exhibit D).

   Second, to illustrate the sensitivity of the unit cost price to the demands utilized, an example was prepared assuming an increase of 100 MW of load. This price was estimated by dividing the transmission revenue requirement by the sum of the average coincidental peak load, plus 100 MW of load (page 6, line 21 of Exhibit D). These illustrative prices provide a range of possible embedded cost of service for transmission service applicable to Tier 1 and Tier 2 QE´s.

C. Tier 3 and Long-term Prices

As stated in Opinion No. 318, "After five years, the commission may consider costing methods other than embedded cost, consistent with general transmission pricing policy."4/ And, "Cost-based (price) is not intended to suggest rates that are limited to an embedded cost."5/ Accordingly, the Company will be developing a methodology for cost-based pricing for long-term transmission services.

In accordance with these general principles, methods will be developed to cost and price three categories of transmission service:

1. service from existing facilities
2. service from facilities the Company will build, and
3. service from facilities the Company will build in cooperation with another utility.

Methodologies to be considered will address both the value of existing investment and the cost of new facilities. Alternative approaches will be considered by the Company, including embedded cost, replacement cost, marginal cost, or other costing methodologies to be identified.

The development of costing and pricing methodologies other than embedded cost may also apply to Tier 3 and other utilities under the wheeling policy for the five year transition period as well as for subsequent time periods. However, for planning purposes, the Company is willing to assure such utilities that the price during the five year transition period which is assumed to end in 1993, will not exceed 150% of embedded cost. (See page 6 of Exhibit D.) The Company anticipates that the FERC's transmission policy will undergo considerable development during the transition period. Thus, the methodology adopted for the first five years may not be the same as the one which is adopted for subsequent periods. The Company will continue in its efforts to develop methodologies for both time periods.

4/ Page 42, FERC Opinion No. 318
5/ Page 39, Note 163, FERC Opinion No. 318, parenthetical reference added

When the Company builds new facilities to accommodate firm transmission service requests, rates will be designed to cover the full cost of providing service. As Opinion No. 318 stated, "Where additional capacity is needed to meet a request, rates may be designed to specifically assign the cost of that capacity addition to the party requesting service."[6/]

Facilities the Company builds in cooperation with other utilities will be priced to capture separately the cost the Company incurs and the cost the cooperating utility incurs to provide the new facilities. The price must also reflect the value inherent in the Company's existing system into which the additions will be integrated. Again, various costing methods will be considered as with the other forms of service.

The Company's methodology, and the FERC's transmission policy, are expected to be in a state of development during the next five years. During that time period, the Company will be developing appropriate methodologies to cost and price its transmission service. These new methodologies constitute a largely undeveloped area of costing and pricing in the industry. The Company is committed to completing the work which will need to be done to make such methodologies understandable and manageable.

6/ Page 39, Note 163, FERC Opinion No. 318

UTAH POWER / PACIFIC POWER
TRANSMISSION COSTS
1987 ACTUAL

	DESCRIPTION (A)	PACIFIC POWER (1987 COSTS) (B)	UTAH POWER (1987 COSTS) (C)	PACIFIC POWER (1987 COSTS) (D)	UTAH POWER (1987 COSTS) (E)
	EXPENSES				
1	TRANSMISSION O & M	38,572	8,379	38,572	8,379
2	ADMINISTRATIVE & GENERAL EXP	4,772	5,319	4,772	5,319
3	DEPRECIATION & AMORTIZATION	17,252	12,954	17,252	12,954
4	AMORT. REFINACING COSTS	428	1,858	428	1,858
5	TAXES OTHER THAN INCOME	6,048	8,687	6,048	8,687
6	INCOME TAXES	15,540	17,515	16,584	18,882
7	TOTAL EXPENSES	82,612	54,712	83,656	56,079
	RATE BASE				
8	PLANT IN SERVICE	665,880	712,173	665,880	712,173
9	RESERVE FOR DEPREC. & AMORT.	(176,184)	(118,665)	(176,184)	(118,665)
10	ACCUM. DEFERRED INCOME TAXES	(79,526)	(75,969)	(79,526)	(75,969)
11	ACCUM. DEFERRED INCOME ITC	(12,300)	(380)	(12,300)	(380)
12	OTHER RATE BASE ITEMS	27,015	29,896	27,015	29,896
13	TOTAL RATE BASE	$424,885	$547,055	$424,885	$547,055
14	RATE OF RETURN /1	10.709%	10.709%	11.131%	11.131%
15	RETURN	45,501	58,584	47,294	60,893
16	REVENUE CREDITS	(454)	(567)	(454)	(567)
17	TOTAL COSTS	127,659	112,729	130,496	116,405
18	AVERAGE COINCIDENTAL PEAK (KW)	4,117,700	2,786,925	4,117,700	2,786,925
19	AVERAGE COST ($/KW)	31.00	40.45	31.69	41.77
20	AVERAGE COINCIDENTAL PEAK (KW) (WITH SENSITIVITY EFFECT OF 100 ADDITIONAL MW)	4,217,700	2,886,925	4,217,700	2,886,925
21	AVERAGE COST ($/KW)	30.27	39.05	30.94	40.32
	/1 COST OF EQUITY	13.25%	13.25%	14.25%	14.25%

Exhibit E

Notice of Succession

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Utah Power & Light Company	)	
PacifiCorp	)	Docket No. EC88-2-000
PC/UP&L Merging Corp.	)	

Notice of Succession

PacifiCorp (an Oregon corporation), doing business as Pacific Power & Light Company and Utah Power & Light Company, whose address is 920 SW Sixth Avenue, Portland, Oregon 97204, on this 5th day of January, 1989, hereby adopts, ratifies and makes its own in every respect all applicable rate schedules, tariffs and supplements thereto, listed below, heretofore filed with the Federal Energy Regulatory Commission by PacifiCorp (a Maine Corporation), doing business as Pacific Power & Light Company and Utah Power & Light Company (a Utah Corporation), effective January 9, 1989:

Pacific Power & Light Company

FPC No.	Effective Date
Tariff - Original Volume No. 1	10/18/72
Tariff - Original Volume No. 2	09/04/75
Tariff - Original Volume No. 3	11/21/82
Tariff - Original Volume No. 4	06/01/83
4	02/15/37
5	02/15/37
7	06/10/37

Pacific Power & Light Company (cont'd)

FPC No.	Effective Date
8 Supp 1	05/04/49
10	01/01/40
10 Supp 1	07/19/41
10 Supp 2	10/16/47
10 Supp 3	02/13/50
13 (Redesignated)	04/30/42
13 Supp 1	05/04/49
15 Exh A	05/27/42
15 Exh B	05/27/42
15 Exh C	05/27/42
15 Exh D	05/27/42
15 Supp 1A	08/31/42
15 Supp 1B	08/31/42
15 Supp 2	08/09/65
19	06/24/47
19 Supp 1 to 1	07/11/55
19 Supp 2	02/02/58
21 Supp 1	07/28/66
25 Supp 1	10/01/50
28 Supp 6 to 26	07/28/60
28 Supp 2 to 27	06/25/66
28 Supp 28	11/12/55
28 Supp 2 to 28	07/28/66
28 Supp 29	11/28/55
28 Supp 2 to 29	08/31/64
28 Supp 3 to 29	01/12/67
28 Supp 1 to 31	07/28/66
28 Supp 1 to 32	07/28/66
28 Supp 1 to 33	07/28/66
28 Supp 1 to 36	08/31/64
28 Supp 3 to 36	01/12/67
28 Supp 4 to 36	08/13/63
28 Supp 1 to 37	01/12/67
28 Supp 2 to 38	11/06/67
28 Supp 3 to 38	04/30/69
28 Supp 3 to 18	01/12/67
28 Exh A to Supp 19	Unknown
28 Supp 1 to 19	09/08/55
28 Supp 2 to 19	01/11/56
28 Exh A to Supp 21	Unknown
28 Supp 1 to 21	09/08/55
28 Exh A to Supp 22	Unknown
28 Supp 1 to 22	09/08/55
28 Supp 1 to 12	05/10/55
28 Supp 4 to 17	07/28/66
28 Supp 2 to 9	06/14/57
28 Supp 11	12/28/53

Pacific Power & Light Company (cont'd)

FPC No.	Effective Date
28 Supp 1 to 11	08/29/55
28 Exh A to Supp 12	Unknown
28 Exh A to Supp 5	Unknown
28 Exh B to Supp 5	Unknown
28 Exh A to Supp 6	04/05/55
28 Supp 1 to 8	06/22/53
28 Supp 2 to 8	09/08/55
28 Supp 1 to 2	11/12/51
28 Supp 2 to 2	Unknown
28 Supp 1 to 3	11/12/51
28 Supp 2 to 3	11/12/51
28 Exh A to Supp 4	Unknown
29 Exh A	Unknown
29 Supp 1	Unknown
29 Supp 2	Unknown
29 Supp 3	Unknown
29 Supp 4	Unknown
29 Supp 5	Unknown
29 Supp 6	05/21/53
29 Exh A to 6	Unknown
29 Supp 7	05/21/53
29 Exh A-2	Unknown
30 Exh B	Unknown
30 Exh C	Unknown
30 Supp 1	10/28/54
30 Supp 2	12/06/54
30 Supp 3	09/01/54
30 Exh A to 6	Unknown
30 Exh A to 3	09/01/54
30 Exh B-1	02/28/55
30 Exh C-1	02/28/55
30 Supp 4	09/01/55
30 Exh A to 4	09/01/55
30 Exh B-6 C-3	09/19/55
30 Exh B-7 C-4	09/19/55
30 Exh B-8 C-5	09/19/55
30 Exh B-9	03/14/55
30 Exh C-6	03/14/55
30 Supp 7	09/01/56
30 Supp 8	09/02/57
30 Supp 9	10/17/57
34 Supp 1	Unknown
34 Supp 2	Unknown
35	05/03/57
35 Exh A	05/03/57
35 Supp 1	06/17/76
36 Exh A to 3 to 1	Unknown

Pacific Power & Light Company (cont'd)

FPC No.	Effective Date
36 Exh B to 3 to 1	09/01/61
36 Supp 4 to 1	09/01/62
36 Exh A to 4 to 1	Unknown
36 Supp 5 to 1	09/01/63
36 Supp 6 to 1	09/01/64
36 Supp 7 to 1	09/01/65
36 Supp 8 to 1	09/01/66
36 Supp 2	09/01/58
36 Supp 1 to 3	07/28/66
36 Supp 4	03/26/65
36 Supp 5	09/01/65
36 Supp 6	07/01/66
37	08/26/58
37 Supp 1	10/04/64
37 Supp 1 to 1 to 1 to 1	08/22/66
37 Supp 2 to 1	05/27/65
37 Supp 2	03/26/65
37 Supp 3	02/25/64
37 Supp 4	04/15/77
37 Supp 1 to Supp 4	09/07/77
37 Supp 5	01/07/78
41 Supp 2	01/30/64
42 Supp 1	Unknown
44 Supp 4	08/31/63
45	12/02/63
45	12/02/63
45 Supp 3	07/10/65
45 Supp 11 to 3	12/02/84
45 Supp 1 to 2 to 3	08/14/67
45 Supp 6	08/14/67
45 Supp 8	07/16/70
45 Supp 10	07/05/71
45 Supp 14	10/01/72
45 Supp 15	03/19/74
45 Supp 16	10/17/76
45 Supp 17	01/01/77
45 Supp 1 to 17	01/01/77
45 Supp 18	01/01/79
45 Supp 1 to 19	11/08/79
45 Supp 20	02/12/85
45 Supp 21	08/15/81
45 Supp 22	04/16/82
48 Supp 1	03/31/65
50	08/31/64
50 Supp 1	09/21/68
50 Supp 2	01/18/69

Pacific Power & Light Company (cont'd)

FPC No.	Effective Date
50	08/31/64
51	08/31/64
51	08/31/64
52	08/31/64
52	08/31/64
53	08/31/64
56 Supp 1	08/29/65
57	08/31/64
59	08/31/64
59	08/31/64
60	08/31/64
61	08/31/64
63	08/31/64
63 Supp 1	04/29/65
66 Supp 3	02/12/85
67	04/01/65
67 Supp 1	04/01/65
67 Supp 2	04/01/65
67 Supp 3	04/01/65
67 Supp 1 to 3	04/01/67
67 Supp 2 to 3	04/01/70
68 Supp 1	06/05/66
69 - A	12/30/65
69 - B	12/30/65
70	12/09/65
70 Supp 1	10/01/71
70 Supp 1	10/01/71
70 Supp 1	10/01/71
70 Supp 1 to 1	07/01/72
71	02/15/66
72	11/05/56
73 Supp 1	05/13/68
74 Supp 1	07/06/69
75 Supp 1	10/29/67
76 Supp 1	04/18/68
77	07/20/67
78 Supp 1	07/01/68
79 Supp 1	02/17/85
80 Supp 1	02/17/85
83	09/20/67
83 Supp 1	12/02/85
84	09/01/66
84 Supp 1	06/30/78
85	12/30/67
86	12/07/67
87	01/05/70
88 Supp 1	02/12/85

Pacific Power & Light Company (cont'd)

FPC No.	Effective Date
91 Supp 1	07/05/71
92	08/10/70
93	11/16/70
93 Exh A	None
94	11/08/70
95 Supp 1	07/05/71
97	05/23/71
97 Supp 1	12/18/73
98 Supp 1	03/16/85
101 Supp 1	02/12/85
102	01/25/72
104 Supp 1	02/27/82
105	08/03/72
106 Supp 1	02/12/85
107 Supp 1	02/12/85
109 Supp 1	02/17/85
110 Supp 1	02/17/85
111 Supp 4	11/30/78
112 Supp 2	05/19/85
114 Supp 4	08/09/73
114	08/09/73
114 Supp 5	08/09/73
114 Supp 1 to 5	08/09/73
114 Supp 2 to 5	08/09/73
114 Supp 3 to 5	08/09/73
114 Supp 1 to 8	08/09/73
114 Supp 1 to 9	08/09/73
114 Supp 10	08/09/73
114 Ex A to 10	08/09/73
114 Supp 2 to 10	08/09/73
114 Supp 11	08/09/73
114 Ex A to 11	08/09/73
114 Supp 1 to 11	08/09/73
114 Supp 2 to 11	08/09/73
114 Supp 3 to 11	08/09/73
114 Supp 4 to 11	08/09/73
114 Supp 5 to 11	08/09/73
114 Supp 13	08/09/73
114 Supp 1 to 13	08/09/73
114 Supp 15	08/09/73
114 Supp 1 to 15	08/09/73
114 Supp 17	08/09/73
114 Supp 1 to 19	08/09/73
114 Ex A to 19	08/09/73
114 Supp 22	08/09/73
114 Supp 25	05/15/75
114 Supp 26	06/30/76

Pacific Power & Light Company (cont'd)

FPC No.	Effective Date
114 Supp 27	06/30/76
114 Supp 28	12/20/74
114 Supp 29	12/20/74
114 Supp 30	12/20/74
114 Supp 32	12/20/74
114 Supp 33	12/20/74
114 Supp 34	02/12/85
114 Supp 35	07/01/81
114 Supp 36	07/01/81
114 Supp 37	07/01/81
114 Supp 38	07/01/81
114 Supp 39	07/01/81
114 Supp 40	07/01/81
114 Supp 41	07/01/81
114 Supp 42	07/01/81
114 Supp 43	07/01/81
114 Supp 44	11/30/85
114 Supp 45	11/30/85
116	09/01/73
116 Supp 1	08/01/76
116 Supp 2	09/01/81
123	03/26/76
123 Exh A	03/26/76
123 Supp 1	02/01/77
123 Supp 2	02/01/78
123 Supp 3	07/17/78
123 Supp 4	07/01/78
123 Supp 5	01/28/80
123 Supp 6	01/28/80
123 Supp 7	07/09/81
123 Supp 8	07/20/83
123 Supp 9	04/07/84
123 Supp 10	01/23/85
123 Supp 11	06/01/85
123 Supp 12	09/30/85
123 Supp 13	09/30/86
124 Supp 1	02/12/85
127 Supp 1	02/12/85
128	09/26/76
132	12/28/76
132 Supp 1	12/16/78
136	05/01/78
137	07/01/78
141	10/21/77
147	05/01/77
153	05/01/78
153 Supp 1	12/11/82

Pacific Power & Light Company (cont'd)

FPC No.	Effective Date
159	02/16/79
160	06/03/65
160 Supp 3	07/01/80
173 Supp 1	02/12/85
174	01/01/80
178	08/07/79
179	08/07/79
187	06/16/80
200	07/21/80
201	07/01/80
203	01/01/80
203 Exh A	01/01/80
206 Supp 1	12/01/84
207 Supp 1	12/01/84
208	07/01/81
209	04/01/81
210	04/01/81
211	12/28/81
213	11/01/81
213 Supp 1	08/24/84
213 Supp 2	10/01/84
213 Supp 3	07/19/86
213 Supp 4	10/01/86
214	11/01/80
219	06/05/82
220	08/02/82
225	06/21/82
226	04/01/78
226 Supp 1	05/17/82
227	12/20/82
229	10/01/82
230 Supp 1	02/12/85
232 Supp 1	09/01/84
233	07/01/83
234	09/01/83
234 Supp 1	09/01/83
234 Supp 1 to 1	09/01/83
234 Supp 2	09/01/83
234 Exh A	09/01/83
234 Exh A to Exh A	09/01/83
235 Supp 1	01/25/84
236	01/01/84
237	07/01/81
237 Supp 1	07/01/81
237 Supp 2	07/01/81
237 Supp 3	07/01/81
237 Supp 1 to 3	11/17/83

Pacific Power & Light Company (cont'd)

FPC No.	Effective Date
237 Supp 2 to 3	11/17/83
237 Supp 5	07/01/81
237 Supp 6	07/01/81
137 Supp 7	11/17/83
237 Supp 8	08/31/85
239	07/01/83
239 Exh A	07/01/83
239 Supp 1	07/01/83
241	09/05/85
241 Supp 1	09/05/85
243	03/12/86
245	08/01/86
246	07/01/87
247	07/01/87
248	08/01/87
249	01/01/90
250	01/01/90
250 Supp 1	01/01/90
251	01/01/87
252	12/14/87
253	07/01/88

Utah Power & Light Company

FPC No.	Effective Date
Tariff - Original Volume No. 2	04/01/82
Tariff - Fourth Rev. Volume No. 1	
Service Sch. RS-TR	06/13/85
Service Sch. RS-PR	06/13/85
Service Sch. RS-RP	08/01/85
Supp 2 to Service Agreement 21	11/23/85
Supp 1 to Service Agreement 21	11/13/84
Supp 1 to 2 to Service Agmt. 21	
Paras. 13-18	07/01/87
Balance	04/18/88
Supp 1 to 1 to 2 to Service Agmt. 21, Para. 9	07/01/87
Supp 2 to 1 to 2 to Service Agmt. 21	07/01/87

Utah Power & Light Company (cont'd)

FPC No.	Effective Date
19	05/07/41
89	10/20/64
95	03/11/65
98	04/25/65
99	04/25/65
103	12/09/65
106	07/01/71
107	06/01/71
108	04/15/72
110	06/01/74
111	06/01/74
112	09/01/73
113	04/03/73
114	10/01/73
115	12/03/73
117	11/04/74
118	12/31/75
119	06/01/75
126	Unknown Contract 08/16/64
126 Supp 2	04/18/86
127	12/30/65
128	12/30/65
120	01/25/78
121	07/15/77
122	Unknown Contract 10/24/73
123	07/13/79
125	Unknown Contract 05/20/80
130	10/01/81
131 Supp 2	10/01/81
131 Supp 3	10/01/81
132	10/01/65
133	04/01/65
134	07/01/85
135	Unknown Filed 05/06/85
136	Unknown Filed 05/06/85
137	01/13/87
138	01/13/87
139	04/01/87
140	04/01/87

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