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UNITED STATES GENERAL ACCOUNTING OFFICE
WASHINGTON, D.C. 20548

ENERGY AND MINERALS
DIVISION

JANUARY 4, 1980

B-197309

111233

The Honorable Pat Williams
House of Representatives

Dear Mr. Williams:

Subject: Review of Peaking Power Needs in the Pacific Northwest (EMD-80-46)

This is in response to your letter of September 27, 1979, concerning our recent review of the Libby Reregulating Dam Project. Your letter requested that our work address:

--The benefit-cost analysis used to justify the Libby Reregulating dam.

--The effect reduced river fluctuations would have on power generation.

--The sustained peaking adjustment used for the first time in the West Group utilities' forecast for 1979-99.

The first two of the three matters were covered in our report of November 20, 1979. 1/ With respect to the benefit-cost analysis, we reported that the Corps of Engineers had overstated the project's benefits by using out-dated and inappropriate calculation methods. The Corps of Engineers plans to conduct a new benefit-cost study using more appropriate methodology and more precise data.

Regarding the effects of river fluctuations, our report showed that reduced fluctuation limits could impair operating flexibility of the main dam and decrease power benefits at the reregulating dam. We found no evidence of significant benefits to fisheries or other purposes which would justify reduced fluctuation limits.

1/"Montana's Libby Dam Project: More Study Needed Before Adding Generators and a Reregulating Dam," EMD-80-25, Nov. 20, 1979.

(005201)

Information bearing on peak power planning in the Pacific Northwest, and more specifically on the sustained peaking adjustment, was provided to you and the Montana congressional delegation in our briefing on May 9, 1979. That information--supplemented somewhat with the results of our recent work--is documented in enclosure I. Our analysis of the sustained peaking adjustment indicated that, in concept, it is an improved way of measuring the sustained capability of the Federal hydropower system. It is a new adjustment, however, and may need to be refined.

Our previous review of electrical energy options for the region 1/ and a brief scrutiny of the West Group utilities' 1979-99 forecasts indicated that--regardless of the accuracy of the sustained peaking adjustment--uncertainty exists about how best to meet future peaking needs. Conservative aspects of the West Group forecast and the presence of several alternative ways to balance peak power supply and demand indicate to us that important decisions need not be hurried. Regional power planners should not rush to build additional peaking units, but should take adequate time to scrutinize forecasting practices and to evaluate the costs and benefits of alternative ways to meet peak power needs.

In summary, we trust that our report of November 20 and enclosure I will fully meet the needs expressed in your letter of September 27. We would be pleased to meet with you or your representatives to further explain our views on these matters.

Sincerely yours,

J. Dexter Peach
J. Dexter Peach
Director

Enclosures - 2

1/"Region at the Crossroads--The Pacific Northwest Searches for New Sources of Electric Energy," EMD-78-76, Aug. 10, 1978.

PEAK POWER PLANNING IN THE PACIFIC NORTHWEST

FORECASTING LOADS AND RESOURCES

DLG 03579

Each year the Pacific Northwest Utilities Conference Committee (PNUCC) estimates the region's need for additional power resources in two reports, the "West Group Forecast of Power Loads and Resources" and the "Long-Range Projection of Power Loads and Resources for Thermal Planning." The West Group Forecast summarizes regional loads and resources for 11 future years, while the Long-Range Projection covers a 20-year planning period and presents a more detailed analysis of loads and resources for each major utility in the region. (See enc. II.)

Each of these reports matches existing and planned generating facilities against load forecasts. If the reports indicate a future energy or peaking deficit for the region, the individual utility with the largest deficit becomes a likely candidate to sponsor a new generating project. Other utilities with probable deficits are candidates for joint participation in the new project. The Bonneville Power Administration (BPA) coordinates its plans with regional utility planning, and according to a BPA internal memorandum, "BPA planning will be based upon the PNUCC Long-Range Projection of Power Loads and Resources * * *."

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Within the region, other organizations--such as State energy departments--also prepare forecasts of average energy needs. But PNUCC makes the only forecast of the region's peak power needs. The manner in which PNUCC forecasts the region's peaking loads and resources is discussed briefly below.

Peakloads

The projected regional peakloads shown in the PNUCC Forecast and Long-Range Projection represent the estimated maximum average 60-minute load. PNUCC's projection was not developed as a single forecast. It is a compilation of the estimated loads of BPA and 12 public and private utilities. BPA's load, in itself, includes input for (1) about 100 utilities which BPA helps in making forecasts, (2) three utilities which make their own forecasts, and (3) both the firm and interruptible power loads of Bonneville's direct service industrial customers (DSIs).

These individual energy forecasts form the basis for determining peaking needs. According to PNUCC officials, the utilities generally derive their peaking forecasts from their energy forecasts, based on historical relationships between peakloads and average energy loads. The accuracy of PNUCC's peaking forecasts, therefore, is directly related to the accuracy of the individual utilities' energy forecasts.

We did not review the various individual forecasts which are aggregated in the PNUCC projections. However, we do have some concerns about the accuracy of PNUCC's peaking forecast for the region. These concerns are discussed in a later section of this report.

Peaking resources

PNUCC's estimates of the region's peaking resources are developed in two steps. The first step involves calculating the region's gross capability by adding together the rated capacities of all thermal and hydroelectric generating facilities. Both existing and planned facilities are included in this projection. New thermal plants are included if PNUCC considers them essential to meet area load requirements. Inclusion of a new thermal plant usually implies that major equipment has been ordered and plant sponsors have been identified. The criteria for including new Federal hydro projects in the forecast require that the projects are authorized and under construction, or are funded for construction or preconstruction planning. Non-Federal hydroprojects are included if they have been licensed by the Federal Energy Regulatory Commission. The capabilities of hydroelectric plants are based on their expected output during critical streamflow conditions.

The second step in resource planning consists of (1) providing long-term reliability by reserving some of the gross generating capacity to cover contingencies and (2) adjusting the rated capacity of hydropower facilities to recognize, for planning purposes, that the hydroelectric system cannot maintain its instantaneous peak output for extended periods. This last factor is known as the "sustained peaking adjustment."

As shown in enclosure II, regional peaking reserves are broken down in the Long-Range Projection into four major categories. The combined reserve requirement for these categories is specified in the uniform regional planning assumptions adopted by PNUCC to be the greater of

--forced outage reserves (computed so that the probability of a loss of load will not exceed 5 percent per year), plus one-half year's load growth and hydro maintenance (a statistical criterion), or

--12 percent of the peakload for the first year of the forecast, increasing 1 percent per year up to 20 percent and remaining at 20 percent thereafter. This is a "rolling" criterion which starts anew at 12 percent at the beginning of each annual forecast.

The "rolling" criterion has been used in all recent PNUCC forecasts.

ANALYSIS OF THE SUSTAINED PEAKING ADJUSTMENT

We examined the sustained peaking adjustment in some detail because it was of special interest to the Montana delegation. This adjustment appeared for the first time in PNUCC's 1979 forecast. It reduced the reported capability of the Federal hydrosystem by about 1,400 megawatts 1/ and contributed significantly to PNUCC's projected peaking deficits. The rationale for the sustained peaking adjustment is described below.

The Federal Columbia River Power System consists of a series of 30 dams, each of which has one or more installed hydroelectric generators. The maximum instantaneous electric output from this system is dependent on the height of the water behind each dam at a particular time. The system cannot be counted on to continuously operate at this instantaneous output level, however, for several reasons:

1/The sustained peaking adjustment shown in the forecast included 1,543 megawatts due to temporary restriction on the output from Grand Coulee Dam. We have not included this restriction in this discussion of the sustained peaking.

--Some dams cannot store enough water to produce their maximum power over extended periods of time.

--The water being used at one dam can be replaced with water released from the next dam upstream. In many cases, however, it takes considerable time for the water to travel from one dam to the next. During this delay, the downstream dam's output is limited.

--Hydraulic imbalance prevents certain dams from operating at their full capacity without spilling water. 1/ The turbines in an upstream dam may not be able to discharge water as fast as a downstream dam, and as a result the downstream plant could run low on water unless the upstream project both generates and spills. The reverse situation (the downstream dam has more limited capacity than the upstream dam) can also occur, in which case the upstream dam would have to reduce its output to prevent spilling at the downstream project.

--Nonpower constraints, such as river fluctuation limits and minimum flow requirements for navigation, recreation, or fishing interests, may limit the output which could otherwise be achieved at hydropower projects.

Until 1979, regional power planners had attempted to account for these limiting factors by applying a 5-percent "realization" (reduction) factor to the Federal hydrosystem's installed peaking capacity. However, BPA officials had recognized for some time that the realization factor only approximated the real limitations on the sustained peaking capability of the Federal hydrosystem. In its 1979 forecast BPA substituted a "sustained peaking adjustment" for the realization factor on the Federal hydrosystem.

The sustained peaking adjustment reduces the Federal hydrosystem's projected capacity to the highest average

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1/The passing of water over the dam rather than through the turbines.

level which it can maintain for 10 hours per day, 5 days per week. BPA determined this adjustment through computer simulation, assuming critical (1936-37) water conditions, no significant spillage, and compliance with all nonpower constraints (flow rates, fluctuation rates, etc.). The simulation showed that the highest 10-hour sustained load which the Federal hydrosystem could meet was about 12 percent (2,400 MW) below the system's 1-hour peak. The major cause of this reduction was an inability of upstream reservoirs to supply sufficient water to maintain water levels in downstream plants. This condition is reportedly most pronounced at four Lower Snake River dams. Only when the Salmon River, which is unregulated by dams, flows high in the spring runoff is there sufficient water to fully load the Lower Snake River generating plants for sustained periods. According to BPA officials, the sustainable peak would not increase very much in good water years.

We believe that BPA's sustained peaking adjustment is a valid refinement for measuring the Federal hydrosystem's capabilities. Although this adjustment was applied only to the Federal hydrosystem in PNUCC's 1979-99 forecast, several northwest utilities have recognized the need to apply such adjustments to their hydrosystems. We should point out, however, that uncertainty exists as to what time period best represents a sustained regional peaking need. BPA selected a 10-hour period as being most representative, but it has also considered 6- and 14-hour peak periods. The Corps of Engineers believes a 14-hour peak period (which would lower projected capabilities by another 600 MW) would be better because a longer peak is more likely during periods when extremely cold weather causes high demand.

NEED FOR ADDITIONAL PEAKING RESOURCES

BPA's introduction of the sustained peaking adjustment caused PNUCC to project serious peaking deficits in 8 out of the next 11 years. Although we agree with the use of a sustained peaking adjustment, we doubt that additional peaking facilities are so urgently needed that important decisions should be rushed. Our brief review of regional power planning practices led us to believe that regional power planners should not hurry their judgments on constructing new peaking facilities because (1) present forecasting methodologies are questionable and (2) adequate time should be taken to thoroughly compare the costs and benefits of alternative means of meeting peak power needs.

FORECASTING METHODS USED

Comparability of loads and resources

The deficits shown in the PNUCC forecast represent the difference between the maximum 1-hour load and the highest average generation which can be sustained for a 10-hour period. A BPA official told us that such an imbalanced comparison would show a larger deficit than is actually the case. However, he thought that the difference would not be great. We believe that good planning requires use of a forecasted peakload which is comparable to the forecasted available resources--i.e., a 10-hour sustained peakload should be compared to a 10-hour sustained generating capacity. We noticed that the average sustained peakload on the BPA system during one extremely cold week in the winter of 1978-79 was about 8 percent below the highest 1-hour peakload. If this relationship holds true for all peakloads in the region, PNUCC's forecast peak could be reduced by over 2,000 MW. This would eliminate most of the peak power deficits forecasted by PNUCC through 1989.

Planning reserves based on conservative policies

Based on certain assumptions we believe that PNUCC's reserves for contingencies may be overly conservative. Three factors contribute to this conclusion. First, loss-of-load calculations are based on the probability of no more than one expected outage in 20 years. Most utilities in other regions require a reliability of no more than one expected outage in 10 years--a level which may still be too high, according to a recent report by the Congressional Research Service. 1/ Second, the region's planned reliability appears to have been even greater than this once-in-20-years probability, because of the conservative "rolling" criterion used for estimating system reserve requirements. Finally, over 1,000 MW of power sold by BPA to its direct service industrial customers can be interrupted at any time for any reason, and could be used as system reserves to help meet peaking needs. 2/ This reserve, however, has

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1/"Are the Electric Utilities Gold Plated? A Perspective on Electric Utility Reliability," Congressional Research Service, Apr. 1979.

2/The potential use of the interruptible DSI load as a regional reserve is discussed in more detail in our Report, "Impacts and Implications of the Pacific Northwest Power Bill," EMD-79-105, Sept. 4, 1979.

not been taken into account in determining the region's peaking surplus or deficit.

Forecasting accuracy

While we did not review the PNUCC peaking forecast in detail, we found evidence which raised questions about its accuracy. A private consulting firm which prepared a study 1/ of the PNUCC forecasts for BPA in 1976, identified several deficiencies. The consultant's report showed that forecasting methods used by utilities were different, varying from simple trend analysis to sophisticated modeling techniques. It also showed that (1) variables used for forecasting differed between utilities, (2) no allowances were made for price elasticity, and (3) forecasts were seldom formally checked for accuracy. A PNUCC official told us that PNUCC cannot mandate that utilities use any standard forecasting methodology assumptions nor do they check to see if the uniform regional planning assumptions are being followed. We also noticed that, although PNUCC has been reducing its projected rate of increase for peak loads, actual peak loads in the region reportedly averaged nearly 8 percent below forecasted peakloads during the period 1973 to 1977.

ALTERNATIVES TO MEETING PEAKING NEEDS

Spilling water to meet peaks

Gains in peaking capability could be made by spilling water when necessary. Such a procedure sacrifices energy which could have been generated by the water spilled and is therefore not a particularly desirable way of meeting peakloads. Nevertheless, this procedure has been used at times in the past, and, according to a BPA official, Bonneville will do so again if it is the only way to meet the load. A BPA analysis showed that spilling a weekly average of 20,000 cubic feet per second at the Dworshak Dam would increase the sustained peaking capability of the Lower Snake River plants by 1,000 MW during peak hours. BPA computed a benefit/cost ratio of 1.9 if spills were required for 40 days each year, but estimated that this procedure would be needed only 10 days per year. The reduction to 10 days per year

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1/"Review of Energy Forecasting Methodologies and Assumptions," Ernst and Ernst, June 1976.

would increase the benefit/cost ratio considerably. We believe that BPA's benefit/cost analysis is conservative, and that the actual benefits from spilling water at Dworshak Dam could be much higher.

Other alternatives identified by GAO

Our report, "Montana's Libby Dam Project: More Study Needed Before Adding Generators and a Reregulating Dam" (EMD-80-25, Nov. 20, 1979), identified five other potentially viable ways to increase generating resources and to better manage peak power loads. These alternatives are:

(1) --Combustion turbines, which are similar to aircraft engines except that they drive electric generators.

(2) --Cogeneration, which uses heat from industrial operations to power electrical generators.

(3) --Power exchanges using the intertie, which stretches from California to Washington and has an existing capacity of 4,100 MW.

(4) --Load management, which can smooth out the peaks in electricity use by means of remote control switches, thermostats, and circuit breakers in homes and businesses.

(5) --Peak pricing options, which involve increasing power prices during periods of heaviest demand.

We believe that BPA should thoroughly analyze ~~these and~~ other potential means of balancing peakloads as a means of selecting the most cost-effective alternatives for implementation. including:

Peak Power Loads and Resources for the Pacific Northwest through 1999

Table 1, p. 1

W. G. Area

Figures are January Peak and Contract Year Average Energy in Megawatts

Table 1

	1979-80 PK	1979-80 AVG	1980-81 PK	1980-81 AVG	1981-82 PK	1981-82 AVG	1982-83 PK	1982-83 AVG	1983-84 PK	1983-84 AVG	1984-85 PK	1984-85 AVG	1985-86 PK	1985-86 AVG
LOADS														
1 SYSTEM LOADS	26840	16744	27344	17570	28675	18190	30046	19326	31163	20028	32296	20720	33514	21422
2 EXPORTS	2066	629	2108	665	1754	562	1760	351	1562	203	1563	205	1565	207
3 TOTAL LOADS	28906	17373	29452	18235	30429	18752	31806	19677	32725	20231	33859	20925	35079	21629
RESOURCES														
4 MAIN HYDRO	28846	11603	28970	11639	29422	11669	29713	11667	30232	11696	30401	11694	30543	11667
5 INDEPENDENT HYDRO	659	434	659	434	659	434	659	434	659	434	659	434	659	434
6 TOTAL HYDRO	29505	12037	29629	12069	30081	12103	30372	12101	30891	12130	31060	12128	31202	12101
7 EX. SM. THRM. & MISC.	224	54	218	53	218	53	218	53	218	53	218	53	211	52
8 COMB. TURBINES	1198	109	1196	109	1198	109	1198	109	1198	109	1198	109	1198	109
9 HANFORD	0	515	0	515	0	515	0	515	0	0	0	0	0	0
10 IMPORTS	1324	1409	1415	1503	1640	1657	1701	1640	1641	1494	1572	1455	1498	1426
11 CENTRALIA	1313	903	1313	902	1313	957	1313	913	1313	1000	1313	957	1313	870
12 TROJAN	1130	800	1130	800	1130	800	1130	800	1130	800	1130	800	1130	800
13 COLSTRIP 1 & 2	330	251	330	251	330	251	330	251	330	251	330	251	330	251
14 WNP 2	0	0	0	0	1100	550	1100	790	1100	825	1100	825	1100	825
15 BOARDMAN (CARTY COAL)	0	0	477	191	477	334	477	358	477	358	477	358	477	358
16 COLSTRIP 3 & 4	0	0	0	0	0	0	0	0	420	294	840	577	840	630
17 WNP 1	0	0	0	0	0	0	0	0	1250	438	1250	860	1250	938
18 WNP 4	0	0	0	0	0	0	0	0	0	0	0	62	1250	765
19 WNP 3	0	0	0	0	0	0	0	0	0	0	0	248	1240	806
20 SKAGIT 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 WNP 5	0	0	0	0	0	0	0	0	0	0	0	0	0	62
22 PEBBLE SPRINGS 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23 SKAGIT 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24 PEBBLE SPRINGS 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 TOTAL RESOURCES	35024	16158	35710	16393	37607	17329	37919	17530	39960	17752	40480	18603	43039	19993
26 HYDRO,SM,THML,& MISC.RES.	1546	0	1552	0	1575	0	1589	0	1615	0	1624	0	1631	0
27 LARGE THERMAL RES.	416	0	488	0	652	0	653	0	903	0	966	0	1348	0
28 PLANNING RESERVES	604	0	901	0	1221	0	1725	0	1911	0	2306	0	2463	0
29 LOAD GROWTH RESERVES	559	330	534	318	566	330	548	325	557	324	594	336	599	349
30 SUS. PKNG. ADJUSTMENT	3963	0	3978	0	4033	0	4063	0	2552	0	2573	0	2589	0
31 HYDRO MAINTENANCE	0	34	0	34	0	34	0	34	0	32	0	33	0	33
32 BPA NW-SW INTERTIE LOSSES	84	20	84	20	57	11	57	1	50	0	50	0	50	0
33 NET RESOURCES	27852	15774	28093	16021	29583	16954	29292	17170	32380	17396	32379	18314	34367	19611
34 SURPLUS OR DEFICIT	-294	-1599	-1359	-2214	-846	-1998	-2514	-2459	-345	-2835	-1484	-2611	-712	-2018
35 BPA IND. INTERRUPTIBLE	1026	1015	1079	1066	1077	1050	1068	1058	1078	1068	1088	1078	1098	1088

ENCLOSURE II

ENCLOSURE II

Peak Power Loads and Resources for the Pacific Northwest through 1999

Figures are January Peak and Contract Year Average Energy in Megawatts

Table 1, p. 2
W. C. Area

	1986-87 PK	1986-87 AVG	1987-88 PK	1987-88 AVG	1988-89 PK	1988-89 AVG	1989-90 PK	1989-90 AVG	1990-91 PK	1990-91 AVG	1991-92 PK	1991-92 AVG	1992-93 PK	1992-93 AVG
LOADS														
1 SYSTEM LOADS	34785	22157	36100	22922	37462	23717	38845	24538	40320	25404	41752	26270	43306	27182
2 EXPORTS	989	209	240	201	106	174	108	177	105	174	105	174	105	174
3 TOTAL LOADS	35774	22366	36340	23123	37568	23891	38953	24715	40425	25578	41857	26444	43411	27356
RESOURCES														
4 MAIN HYDRO	30480	11674	30590	11703	30528	11697	30554	11647	30554	11647	30554	11647	30554	11647
5 INDEPENDENT HYDRO	659	434	659	414	659	434	659	434	659	434	659	434	659	434
6 TOTAL HYDRO	31139	12104	31249	12117	31187	12131	31213	12081	31213	12081	31213	12081	31213	12081
7 EX. SM. THRM. & MISC.	211	52	211	52	211	52	211	52	211	52	211	52	211	52
8 COMB. TURBINES	1198	109	1198	109	1198	109	1198	109	1198	109	1198	109	1198	109
9 HANFORD	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 IMPORTS	1417	1215	1332	955	1240	887	1142	734	1036	671	923	591	808	505
11 CENTRALIA	1313	914	1313	935	1313	957	1313	935	1313	935	1313	935	1313	935
12 TROJAN	1130	800	1130	800	1130	800	1130	800	1130	800	1130	800	1130	800
13 COLSTRIP 1 & 2	330	251	330	251	330	251	330	251	330	251	330	251	330	251
14 WNP 2	1100	825	1100	825	1100	825	1100	825	1100	825	1100	825	1100	825
15 BOARDMAN (CARTY COAL)	477	358	477	358	477	358	477	358	477	358	477	358	477	358
16 COLSTRIP 3 & 4	840	630	840	630	840	610	840	630	840	630	840	630	840	630
17 WNP 1	1250	930	1250	930	1250	930	1250	930	1250	930	1250	930	1250	930
18 WNP 4	1250	934	1250	930	1250	930	1250	930	1250	930	1250	930	1250	930
19 WNP 3	1240	930	1240	930	1240	930	1240	930	1240	930	1240	930	1240	930
20 SKAGIT 1	1288	515	1288	902	1288	966	1288	966	1288	966	1288	966	1288	966
21 WNP 5	1240	759	1240	930	1240	930	1240	930	1240	930	1240	930	1240	930
22 PEBBLE SPRINGS 1	0	252	1260	819	1260	945	1260	945	1260	945	1260	945	1260	945
23 SKAGIT 2	0	0	0	0	1288	515	1288	902	1288	966	1288	966	1288	966
24 PEBBLE SPRINGS 2	0	0	0	0	0	189	1260	883	1260	945	1260	945	1260	945
25 TOTAL RESOURCES	45423	21594	46700	22509	47042	23271	49030	24127	48924	24270	48811	24190	48688	24104
26 HYDRO, SM. THML. & MISC. RES.	1627	0	1633	0	1630	0	1631	0	1631	0	1631	0	1631	0
27 LARGE THERMAL RES.	1719	0	1900	0	2101	0	2290	0	2290	0	2290	0	2290	0
28 PLANNING RESERVES	2644	0	3039	0	3107	0	3152	0	3441	0	3695	0	3991	0
29 LOAD GROWTH RESERVES	619	356	640	368	654	380	696	398	702	409	734	425	749	439
30 SUS. PKNG. ADJUSTMENT	2582	0	2595	0	2587	0	2590	0	2590	0	2590	0	2590	0
31 HYDRO MAINTENANCE	0	34	0	34	0	34	0	34	0	34	0	34	0	34
32 BPA NW-SW INTERTIE LOSSES	26	0	1	0	0	0	0	0	0	0	0	0	0	0
33 NET RESOURCES	36206	21204	36092	22107	37763	22857	38671	23695	38270	23827	37871	23731	37437	23631
34 SURPLUS OR DEFICIT	432	-1162	544	-1016	195	-1034	-282	-1020	-2155	-1751	-3986	-2713	-5974	-3725
35 BPA INT. INTERRUPTIBLE	1100	1090	1110	1107	1127	1117	1137	1127	1147	1137	1157	1147	1167	1157

ENCLOSURE II

ENCLOSURE II

Peak Power Loads and Resources for the Pacific Northwest through 1999

Table 1, p. 3
W. G. Aren

Figures are January Peak and Contract Year Average Energy in Megawatts

	1993-94 PK	1993-94 AVG	1994-95 PK	1994-95 AVG	1995-96 PK	1995-96 AVG	1996-97 PK	1996-97 AVG	1997-98 PK	1997-98 AVG	1998-99 PK	1998-99 AVG
LOADS												
1 SYSTEM LOADS	44892	28123	46519	29080	48236	30067	49996	31094	51831	32166	53795	33289
2 EXPORTS	105	174	105	174	105	174	28	109	28	109	28	109
3 TOTAL LOADS	44997	28297	46624	29254	48341	30241	50024	31203	51859	32275	53823	33398
RESOURCES												
4 MAIN HYDRO	30554	11647	30554	11647	30554	11647	30554	11647	30554	11647	30554	11647
5 INDEPENDENT HYDRO	659	434	659	434	659	434	659	434	659	434	659	434
6 TOTAL HYDRO	31213	12081	31213	12081	31213	12081	31213	12081	31213	12081	31213	12081
7 EX. SH. THRM. & MISC.	211	52	211	52	211	52	211	52	211	52	211	52
8 COMB. TURBINES	1198	109	1198	109	1198	109	1198	109	1198	109	1198	109
9 HANFORD	0	0	0	0	0	0	0	0	0	0	0	0
10 IMPORTS	671	412	530	312	378	205	240	121	240	78	240	67
11 CENTRALIA	1313	935	1313	935	1313	935	1313	935	1313	935	1313	935
12 TROJAN	1130	800	1130	800	1130	800	1130	800	1130	800	1130	800
13 COLSTRIP 1 & 2	330	251	330	251	330	251	330	251	330	251	330	251
2	1100	825	1100	825	1100	825	1100	825	1100	825	1100	825
15 BOARDMAN (CARTY COAL)	477	350	477	350	477	350	477	350	477	350	477	350
16 COLSTRIP 3 & 4	840	630	840	630	840	630	840	630	840	630	840	630
17 WNP 1	1250	938	1250	936	1250	936	1250	938	1250	938	1250	938
18 WNP 4	1250	938	1250	938	1250	938	1250	938	1250	933	1250	938
19 WNP 3	1240	930	1240	930	1240	930	1240	930	1240	930	1240	930
20 SKAGIT 1	1280	966	1280	966	1280	966	1280	966	1280	966	1280	966
21 WNP 5	1240	930	1240	930	1240	930	1240	930	1240	930	1240	930
22 PEBBLE SPRINGS 1	1260	945	1260	943	1260	945	1260	945	1260	945	1260	945
23 SKAGIT 2	1280	966	1280	966	1280	966	1280	966	1280	966	1280	966
24 PEBBLE SPRINGS 2	1260	945	1260	945	1260	945	1260	945	1260	945	1260	945
25 TOTAL RESOURCES	48559	24011	48418	23311	48266	23304	48128	23720	48128	23669	48128	23666
26 HYDRO,SH.THML.& MISC.RES.	1631	0	1631	0	1631	0	1631	0	1631	0	1631	0
27 LARGE THERMAL RES.	2290	0	2290	0	2290	0	2290	0	2290	0	2290	0
28 PLANNING RESERVES	4289	0	4571	0	4806	0	5212	0	5516	0	5842	0
29 LOAD GROWTH RESERVES	760	448	812	462	840	486	866	505	929	532	996	559
30 SUS. PKNG. ADJUSTMENT	2590	0	2590	0	2590	0	2590	0	2590	0	2590	0
31 HYDRO MAINTENANCE	0	34	0	51	0	51	0	51	0	51	0	51
32 BPA NW-SW INTERTIE LOSSES	0	0	0	0	0	0	0	0	0	0	0	0
33 NET RESOURCES	36991	23529	36524	23398	36029	23267	35539	23164	35172	23086	34779	23056
34 SURPLUS OR DEFICIT	-8006	-4768	-10100	-5856	-12312	-6974	-14485	-8039	-16687	-9189	-19044	-10342
35 BPA IND. INTERRUPTIBLE	1177	1167	1187	1176	1197	1186	1207	1196	1217	1206	1226	1215

ENCLOSURE II