AN ABSTRACT OF THE THESIS OF

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In the Columbia Basin Reclamation Project, there are several potential power sites which have been formed in the construction of the irrigation system. It is necessary and desirable to examine these new potentials to determine their physical possibilities and relative advantages and limitations from an engineering and economic standpoint.

During the last 10 years, interest in pumped storage has been stirred again in this country by the development of a reversible pump-turbine unit which can operate at high efficiencies in either direction. Under the proper conditions, this type of unit offers many possibilities, permitting the utilization of a type of hydraulic power drop usually not developed, producing peak energy for the system.

In the usual case, pumped storage consists of pumping from a lower suction pool to an upper reservoir, this pumping to be done with cheap off-peak steam energy, improving the load factor of the steam plant. During the daily load peaks, the water is released from the upper reservoir, flowing reversibly through the pump-turbine units into the lower pool, generating high priced peaking energy. The system requires only a very limited water supply, increasing the system's peak capacity, and gaining an economic advantage in the price differential between cheap off-peak pumping energy and high cost peak energy. There are several plants of this type in Europe, but only two--the Rocky River Plant in Connecticut and Buchanan Dam in Texas--in the United States, although two or more plants are under construction, applying the theory in varying degrees.

The irrigation water pumping plant at Grand Coulee Dam would appear to meet the conditions outlined above in many ways. The pumping station is already constructed with space available for six (6) additional reversible 65,000 hp pump-turbine units. The pumping head varies between 365 to 270 ft. providing a power drop through the installed penstocks. The Feeder Canal connects the pump outlets to the Equalizing Reservoir. Due to the very gentle slope of this connecting canal, reverse flow can occur for a drawdown of 15 ft. from the reservoir full point, representing a live storage of 382,100 acre-ft. for reverse flow.

Since the pumping plant, canal, and reservoir are already constructed to fulfill another purpose, the costs of modification and differential costs between planned for and pumped-storage equipment are all that need be considered in a cost study of a new pumped-storage plant. The two most reasonable alternatives in modifying the present plant are: (a) Using the present

type of pump units reversibly. These units have an output of only about 60% of their pump rating when operated reversibly, and cannot be regulated as they have no wicket-gates. However, the units are considerably less expensive. (b) Using specially designed pump-turbines with wicket-gates. These units have a greater output and efficiency but are more expensive. Both alternatives, in a preliminary cost estimate, cost approximately $30 per kw.

Unfortunately there are several rather serious limitations to this solution. (a) The Feeder Canal limits the reverse flow rather severely, allowing maximum output for a drawdown of only 3.3 ft. or 143 hr. at maximum loads of 180,000 kva for the first alternative and 256,000 kva for the second alternative above, operating six (6) units. (b) Low-cost off-peak steam energy is not available for pumping in the region, or is it likely to be in the near future. (c) This means that nearly all pumping must be done using hydraulic energy. To be justified, this must occur during surplus water periods to use the reserve water storage the most effectively. Without steam energy for pumping, and only very infrequent excess flow periods occurring during the winter at Grand Coulee, the problem becomes limited to a yearly pump and return cycle instead of a 24 hr. cycle as is the usual case. This presents new problems, involving the length of the excess flow period at Coulee, the time required to meet the predicted ultimate irrigation requirements, and the fact that the irrigation s eason is considerably longer than the ideal pumping season. These factors all tend to make it very difficult or impossible to reach the end of the irrigation season in October with the Equalizing Reservoir at a sufficient elevation to provide significant reverse flow energy and capacity. (d) There is a fault of unknown proportions in the side of the Equalizing Reservoir which may make it impossible or inadvisable to maintain the reservoir water level at its upper elevations. Without very extensive and expensive modifications to the Feeder Canal, this would make the entire project unworkable. (e) The distance of Grand Coulee from the load centers makes the value of firm and peak energy at the dam very nearly the same. This destroys the basic economic advantage ordinarily enjoyed by a pumped storage plant. (f) The more complete regulation of the Columbia River by up-stream dams prolong the excess flow period in the summer and provides periods of excess flow in the winter in some years. Although these make the plan more possible, they also make it less necessary, by greatly increasing the firm capacity of the present main stream plants.

These factors make it inadvisable to consider construction of a pumped storage plant at this time. At some future date, as (a) such Equalizing Reservoir leakage as occurs is corrected, (b) additional pumping capacity is required to meet irrigation needs, (c) the load factor of the Northwest Power Pool reaches a more normal value of about 60%, making peak energy more valuable, (d) additional steam plants of high efficiency are constructed in the area to furnish off-peak power for pumping, (e) the Columbia River becomes more completely regulated giving a longer average ideal pumping season in the summer, and winter periods of excess flow in many years, this reverse pump-turbine plant would be advisable. Many of these things should occur in the next 10 years.

There are two types of power shortages that arise in the Northwest, seasonal and cyclic. The seasonal shortages caused by yearly low water periods between December and April, could possibly be remedied by the use of pumped-storage. The more serious type of shortage lasting over many months, is caused by dry years, and occur in approximately four year cycles. This problem is met only by building up a sufficient steam generating capacity in the region. This must be done to give the system a stable base of firm energy independent of climatic variations.

DEVELOPMENT OF BY-PRODUCT POWER IN THE
COLUMBIA BASIN RECLAMATION PROJECT

by

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DEVELOPMENT OF BY-PRODUCT POWER IN THE COLUMBIA BASIN RECLAMATION PROJECT

INTRODUCTION. During the past twenty years, the Northwest has seen a tremendous expansion in its utilization of its river resources. This expansion started with the construction of Grand Coulee Dam, which was just beginning to approach its planned generating capacity at the start of World War II. This power potential and the industrial expansion caused by the war accelerated the influx of population and industry, causing a profound effect on the entire region. The Federal building program now accounts for over 60% of the installed generating capacity in the Northwest. The Northwest Power Pool is at the time of this writing over 90% hydroelectric. The steam capacity making up the remaining 10% consists largely of relatively inefficient plants which serve on a standby basis whenever possible. It is of interest to note that this ratio is considerably different from the 80% steam to 20% hydro ratio of installed capacity for the United States as a whole. This seeming unbalance has grown up in the Northwest partly because of the remarkable flow characteristics of the Columbia River and the huge Federal installations constructed and being constructed to make use of this fact. Another contributing factor is that there are no large high grade fuel deposits in the general areas near the load centers. Further, since the hydroelectric projects have driven the energy rates very low, the construction of new large steam plants has not attracted private capital. This may all be part of the evolution of a power system--the steam, gas turbine, or atomic energy must be added before long, as industry cannot afford to depend on the whims of a beneficient but nevertheless erratic Mother Nature.

Since the Northwest Power Pool is largely dependent upon its water resources, with over 60% of its installed capacity on the Columbia River and its tributaries, it should be noted that the Columbia is not yet regulated to any extent. Grand Coulee Dam is the only dam to be built on the Columbia with any storage capacity, the rest all being run-of-the-river plants, and the reservoir behind Coulee is small relative to the river flow and plant requirements. The completion of Hungry Horse, Albeni, and Cabinet Gorge Dams on the up-stream tributaries will furnish a degree of regulation, with other dams at Libby and Glacier View planned for in the future. Although these dams will help control the Columbia River flow, they will also make the system even more predominately hydroelectric.

The accepted figure for adequate reserve generating capacity is approximately 20%. Reserve generating capacity is usually procured from one or more of the following sources: (a) obsolete steam plants on a standby basis (b) driving new steam plants at above rated condition for the required periods, and (c) standby hydroelectric plants with a reservoir capacity which is sufficient to meet the needs of the system and which can be maintained at optimum level as nearly as possible independent of seasonal changes. Peaking and reserve generating capacity are furnished in much the same manner, and their requirements are very similar.

During periods of sufficient water, the Northwest Power Pool can drive its hydroelectric units at considerably above rated and/or fall back upon its relatively small steam reserve for reserve or peak load capacity. During low water periods, however, which occur seasonally between December and April, or in low water years over longer periods, the system may become embarrassed. There is not enough water to reach even rated capacity in the hydro plants, very little steam reserve, and almost no hydro reserve.

The fact that there are two different types of low water periods is important, as a solution to one may not be correct for the other. A large part of the Columbia River flow usually comes from the melting ice fields in Canada. During the coldest part of the winter (December to April) this source of water almost disappears, giving a seasonal low flow period, which can be at least in part compensated for by released storage at Coulee and above, and by operating the existing steam plants on peak load.

The second type of low river flow is more difficult to handle, and occurs during dry years when there is insufficient precipitation and snow storage in the mountains. The river may be low for a whole year, drawing the reservoir reserves down early in the fall and leaving the entire hydroelectric system crippled. There is no practical hydroelectric solution to this cyclic water shortage. In its present state, the Northwest Power Pool can only run its obsolete steam plants on base load and drop load. The size of the system in this case is its greatest strength, because of its load diversity and diversity of weather conditions.

To adequately meet these types of low water periods, new steam plants of considerable capacity, hydroelectric peaking plants with independent storage facilities, or both, operating to supplement each other should be added to the system. The study of the steam plant problem--their location, size, fuel, and so forth--will not be taken up here. However, they are part of this problem and enter into its solution.

One location for a peak load hydroelectric plant is at Grand Coulee Dam, using the pumping plant and Equalizing Reservoir reversibly as a pumped-storage installation, and the pump units reversibly as pump-turbines. This is the problem studied in all that follows.

The physical location of the pumping plant, penstocks, Feeder Canal, and Equalizing Reservoir are such that reverse operation would appear to be possible without extensive modification. Maximum utilization of existing facilities, with the resultant low cost per kw for construction, the presence of transmission lines leading to load centers, the low addition in fixed operating costs involved in using the plant for both functions, and the possibility of low cost peaking energy, make the proposal look very attractive. However, problems involving the limitation of the Feeder Canal to reverse flow, possible leakage in the Equalizing Reservoir, most efficient use of available water supplies, irrigation water requirements, and other problems, prevent this solution from being as clean cut a decision as might be hoped for.

The different advantages, limitations and a study of various methods of constructing and operating the proposed plant to obtain the optimum benefit are studied and weighed in the following pages.

THEORY.

Definitions. Load factor: The load factor of any system is the ratio obtained by dividing the number of kilowatt-hours over a given length of time by the product of the peak load x the number of hours in this period (daily, week, or year). For example, during a certain week a system turns out 8,400,000 kw-hr, and at the peak load during the week reached 100,000 kw. Therefore, the load factor for that week is (4, p.244):

$$\text{Load factor} = \frac{8,400,000}{100,000 \times 168 \text{ hr/wk.}} = 50\%$$

Capacity factor: The capacity factor for any given period of time (day, week, month) may be defined as the ratio of the energy that the plant actually produced to the energy that the plant might have produced if operated at full capacity throughout the period.

Thus, if during a given week the peak load on a power plant with a capacity of 100,000 kw. was 65,000 kw, and if the energy produced by the plant was 6,720,000 kw-hr, the capacity factor for that week (168 hr.) would be (4, p.214):

$$\text{Capacity factor} = \frac{6,720,000}{100,000 \times 168} = 0.40 \text{ or } 40\%$$

During the same period, however,:

$$\text{Load factor} = \frac{6,720,000}{68,000 \times 168} = 61.6\%$$

The term "plant factor" as used by many engineers is identical with "capacity factor" as here defined.

Base load: Base load is the minimum load over a given period of time.

<u>Peak load</u>: Peak load is the maximum load consumed or produced by a unit or group of units in a stated period of time. It may be the maximum instantaneous load or the max. load average over a designated interval of time.

<u>Dump power</u>: Dump power is hydro power in excess of load requirements that is made available by surplus water.

<u>Firm power</u>: Firm power is the power intended to be always available even under emergency conditions.

<u>Prime power</u>: Prime power is the maximum potential power constantly available for transformation into electric power.

<u>System reserve</u>: System reserve is the capacity, in equipment and conductors, installed in the system in excess of that required to carry peak load.

<u>Load curve</u>: A load curve is a curve of power vs. time showing the value of a specific load for each unit of the period covered.

<u>Load duration curve</u>: The load duration curve is a curve showing the total time, within a specified period, during which the load equalled or exceeded the power values shown (1, pp.117-118).

<u>Firm capacity of hydro electric plants</u>: The firm capacity of a hydro electric plant may be defined as that portion of its total installed capacity which can perform the same function on that portion of the load curve assigned to it as alternative steam capacity could perform.

Firm capacity is dependent on the minimum stream flow available at time of peak load, on the pondage available, on the shape and size of the connected load curve and on the interrelation of existing plants. Occasionally engineers speak of the minimum 24 hr. power available at the hydro plant as the firm power capacity of the plant. The two can be the same only in the case where no pondage at all is available at the plant. With large pondage and favorable load conditions, firm capacity may be many times the min. 24 hr. power available at the site.

The firm capacity of a hydro plant may vary at different seasons of the year, but usually it is firm capacity at time of system peak load which is of significance, and, unless otherwise specified, it is to be understood that the term "firm capacity" means the firm capacity of the hydro plant at time of system peak load (9, p.135-136).

The Classical Problem of Pumped Storage Hydroelectric Power. The principle of pumped storage hydroelectric power is comparable with the direct-current power systems of many years ago in which a great number of large size storage batteries were connected in parallel with the dynamos and were used to take up the rapid load fluctuations. The steam, operating at 100% load factor, carried the base of the load and as fast as excess capacity was released from the load it was used to charge the storage batteries.

The pumped storage hydroelectric project stores the water during the off-peak periods, which is the same as storing energy for later use when it is released and converted to electric energy during the on-peak period. This is obtained by using the available off-peak energy of the steam plants for pumping, and this method of operation increases the load factor of the steam system, which in turn improves their over-all efficiency.

The advantages of pumped storage hydroelectric power are these: In areas where dam sites are available for development but the stream flow is so meager as to make many conventional hydro projects economically infeasible, the adaptation of pumped storage provides an economical means of developing the hydroelectric potentialities of a site that otherwise might be considered as a single-purpose project for other uses than power, with the result that the natural flow and head inherent in the project would not be developed to its fullest. A few relatively high-head pumped storage plants might be used to advantage to supply the peaking requirements of an entire region. The critical period of low flow, which limits the primary energy of a conventional plant becomes of secondary importance with a pumped storage plant. (Of course, in the case involved, the extreme case of an artifical reservoir with no flow at all is considered. This is but an extension of the above case.)

In addition, a pumped storage project has advantages other than the preservation of inherent power potentialities. For example, the off-peak pumping load improves the load factor of the fuel-electric plants supplying such load and thereby improves their efficiency and operating characteristics. This latter factor alone may be decisive in selection of a pumped storage plant over other alternatives. Also, the pumped storage plant has the ability to vary its load factor as required to meet different load conditions, and to furnish reserve capacity by additional pumping in anticipation of a scheduled outage, and the like. Magnitude of such advantages depends to a large extent upon the project location in relation to load centers, the physical characteristics of the site, the type of unit installed and other pertinent features.

Pumped storage projects which obtain off-peak energy from fuel-electric plants may not conserve fuel since more off-peak energy may be required for pumping than is obtained during on-peak generation. However, by making practicable a project which has natural flow and head available and which would otherwise not be developed at all, the final result may be a saving in fuel. The value of pumped storage power lies in its ability to convert low value off-peak steam energy into high value on-peak hydro energy, and also in its capacity value. The dependable capacity can be increased at any project up to the limit of the availability of off-peak energy and water for pumping, consistent with the physical characteristics of the site, thereby increasing the economic attractiveness of the project.

The disadvantages of pumped storage hydroelectric plants are: that they can only be operated as peaking plants; that they must depend upon some other source for off-peak pumping power to make them effective; that provision must be made for a sufficient supply of pumping water; and that the starting of the unit in its pumping sequence may require some additional equipment and assistance from other sources.

Because the question of design is one of economics, it now appears the type of unit that will perhaps better suit the needs of pumped storage hydroelectric development in this country will be the single-speed, vertical, Francis-type, reversible pump-turbine. The tests of two identical models of this type of unit recently developed by Allis-Chalmers Manufacturing Co. indicated a best turbine efficiency of 87 per cent while developing 9450 hp, at 87 ft. head and 163.6 rpm, and the pump performance showed a best efficiency of 88 per cent for a discharge of 1150 cfs at 63 ft. head at 163.6 rpm. A somewhat higher efficiency may be expected in the prototype under actual operating conditions.

This type of unit would be slightly higher in cost than the conventional Francis unit for the same specific speed, and will require a somewhat larger electrical machine in relation to the generation output than would otherwise be required. This is because of the additional horsepower input to the shaft necessary for pumping when acting as a motor. This extra electrical capacity differential will be greatest for design heads of 50 ft. and will become less as the head increases (10, pp.76-78, pp.122-124).

Reversible Pump-Turbine Units. It has been known for a long time that pumps reverse on failure of their driving power and operate as turbines, so the idea of designing a single unit to operate either as a pump or as a hydraulic turbine seems very logical. The advantages of having a unit that can operate in one direction as a pump and in the other as a hydraulic turbine are obvious. A single unit will decrease manufacturing, installation, and operating costs. There are, of course, a number of problems in the design of such a unit.

A single unit must have proper characteristics as a pump as well as a hydraulic turbine, but fortunately these are not too far apart to begin with. The driving motor for the pump must reverse and operate as a generator with characteristics satisfactory for the system to which it is connected.

The pump-turbine is a hydraulic unit with a single runner mounted on a shaft and enclosed in a casing with speed ring and movable guide vanes. It is designed so it can function as a centrifugal pump by being rotated in one direction, or as a hydraulic turbine by being rotated in the opposite direction. The pump is driven by a direct-connected electric motor and pumps water from a suction pool at a lower elevation to a storage reservoir at a higher level.

For generating power the flow cycle is reversed and water is allowed to flow from the storage reservoir through the pump-turbine and discharge into the suction pool. The same runner is now used as a hydraulic turbine and the motor, which is rotated in the opposite direction, is now used as a generator.

A turbine unit requires more head and capacity at its best point of efficiency as a turbine than it develops at its best point of efficiency as a pump. However, from the standpoint of head available from the external system the reverse is true. As a result it is not possible to utilize the maximum pump turbine efficiencies of the unit with the same external system. Introduction of variable guiding apparatus in the casing helps in the effort to make the characteristics of the pump-turbine fit those of the external system. It seems that reliance must still be placed on the gates to improve the fit between the pump-turbine characteristics and those of the external system. There is, of course, another method and that is to pump and generate at different speeds. This would require the equivalent of a 2-speed electrical machine.

At the start of the pumping cycle the suction pool is full and the upper storage reservoir is at its lowest level, hence pumping starts against the lowest head of the pumping period and gradually build up head to the upper limits which depend on the depth of the storage reservoir and the draw-down of the suction pool.

In generating power the net head on the turbine is the static head minus the friction loss in the system. Power generation starts with the high head produced by a full storage reservoir and lowest level in the suction pool and the head then drops gradually to the minimum as the storage pond is drawn down and the suction pool is filled.

It is assumed that the unit will be used in a fairly large power system which can supply power for pumping during the off peak period so that this power can be bought at low cost per kilowatt hour. The unit will generate peak power which can be sold at a much higher price per kw-hr and make the unit economically sound. The unit would not be used for regulating but would supply prime power on the system.

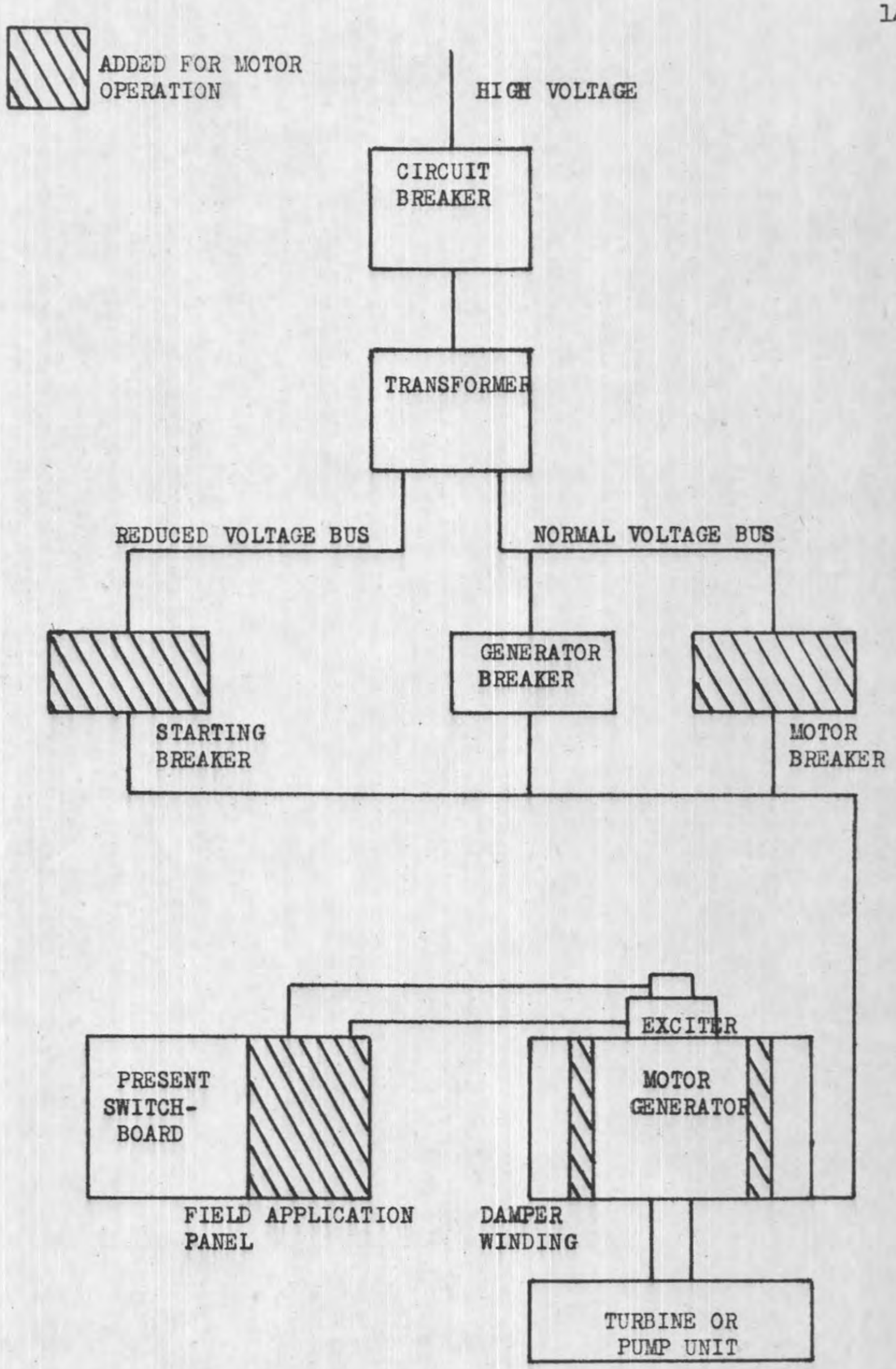
Pump-turbines can be built for heads comparable to those under which Francis turbines are used today. This range would be about 50 to 1000 ft. head. Submergence of the unit is governed by the head used for pumping.

The chief difference between these units and a generating station arise from the necessity of starting and operating the synchronous machine as a motor with a rotation opposite to that required when it operates as a generator. The elementary electrical system for a pump storage hydro-electric plant is shown in the following figure. For the unit operating as a generator the conventional exciter, generator breaker, transformer and circuit breaker would be necessary. For the operation of such a unit as a pump-turbine unit the additional devices required are shown cross-hatched. These would include a starting breaker and a motor breaker and a field application panel, plus damper windings in the generator.

Since the plant would normally operate at the maximum power corresponding to the head available and would do little or no frequency or voltage regulating, need for a pilot exciter might be questioned. Amount of flywheel effect required in the unit might be reduced to the normal value because hydraulic regulating would not be critical.

The starting of the motor on such a pump-turbine unit is the governing factor in designing such a unit and determines what equipment and starting procedure may be used. Minimum full-voltage starting kva of a motor suitable for these conditions would generally be in the range of 200 to 300 per cent. The limiting torque requirement is the break-away torque of the bearings if the pump is unwatered for starting.

Necessity for operating the machine in either direction presents no new problems in the design of the bearings. Large pump motors are usually required to operate without injury at reverse overspeed and bearings suitable for this requirement are in service in many installations. The Kingsbury type of thrust bearing is inherently suitable for either direction of rotation (5, pp.96-100).



MODIFICATION NECESSARY TO CONVERT A TURBINE HYDROELECTRIC ELECTRIC INSTALLATION FOR REVERSABLE PUMP TURBINE ACTION

Specific Speed and Cavitation Problems of Reversible Pump-Turbines. The pumping station at Grand Coulee is already constructed, and it would appear logical to make use of this station in any generating plan that would return water to Lake Roosevelt. As stated elsewhere, there are 12 pump pits constructed, 6 of these having conventional centrifugal pumps installed in them. The remaining 6 pits are to be used later when additional pump capacity is required, although present planning suggests that 2 of the pits may never be used.

The fact that the pump pits are already constructed, and the fact that a reversible pump-turbine unit as designed by Allis-Chalmers Co. differs from the presently installed pumps in that the pump-turbines have wicket-gates brings up some problems in design limitations. If wicket-gate units are used in the present pump pits, it means that the diameter of the impellers must be reduced. This involves some theoretical considerations.

For single stage centrifugal pumps, an approximate equation can be set up between the head, periphial velocity of the impeller, and the constant g.

This is: $h = \frac{V^2 \text{periphial}}{2g}$

or, $V^2\text{periphial} = 2gh = K$ (a constant)

or, $V\text{periphial} = C$ (a constant)

In other words, for a given head, the periphial velocity of the impeller is a constant. As the diameter of the impeller is decreased, the angular velocity or rpm of the impeller must increase in order to keep the periphial velocity constant. The relation between angular velocity and periphial velocity is Vperiphial = r ωangular. Angular velocity may be given in rpm. r is the impeller radius. For a given head and smaller diameter impeller, a higher impeller speed will be required to lift the same amount of water.

By definition, specific speed is the number of revolutions per minute at which a given runner would revolve if it were so reduced in proportions so that it would develop 1 hp under 1 ft head. All homologous wheels of the same type, but of different size, have the same specific speed. An empirical equation which may be used to determine the desirable specific speed for Francis-type wheels is:

$$N_s = \frac{5050}{H + 32} + 19 \text{ , where H is head in feet.}$$

A single runner having a higher specific speed than another therefore runs at a higher rpm to deliver the same hp under the same load. Thus, both specific speed and rpm increase for a smaller diameter impeller doing the same job.

Cavitation must also be considered. In general, the higher the specific speed of the runner for the same power and head, the higher the velocities through the runner and, therefore, the lower must be the setting to avoid cavitation.

Increasing the speed of the impeller would not present a great problem, as the electrical machine connected to the turbine could be designed to fit the requirements quite closely. However, it would be very difficult to set the units lower, should cavitation become a problem.

Physical Definition of Present Problem.

The Columbia River: The Columbia River has the greatest hydroelectric power potential of any river in North America. It drains an area of 260,000 square miles, and its basin includes nearly all of the northwestern states west of the Rocky Mountains, small areas in Wyoming, Utah, and Nevada, and 39,700 square miles of mountainous country in the eastern part of British Columbia. About 60 per cent of the water that passes the Grand Coulee Dam comes out of the river basins in Canada, most of it during the summer-time.

The largest tributary of the Columbia is the Snake River. As it joins the Columbia River in south central Washington, 274 below Grand Coulee Dam, it is not directly of interest in this study.

The second and third largest tributaries of the Columbia River, the Kootenai and the Clark Fork Rivers, join it in Canada. The Kootenai rises in the Canadian Rockies, 75 miles north of the source of the Columbia, and flows south 180 miles into the United States, passing within a few miles of Columbia Lake, the source of the Columbia River. After traversing a 167 mile loop into Montana and Idaho, the Kootenai River returns into Canada, and enters Kootenai Lake, which discharges into the Columbia.

The Clark Fork of the Columbia River drains almost all of Western Montana. From its source in the Rocky Mountains not far from the headwaters of the Missouri River, it flows 360 miles into Lake Pend Oreille in northern Idaho, and then nearly 100 miles west through Idaho and north through Washington, into Washington.

The upper Columbia is characterized by wide variations in its annual flow, having its peak flow during the summer months, usually reaching its maximum in June. Most of its water comes from snow and ice deposits in the high mountains of British Columbia, western Montana, and northern Idaho. Warm weather, thawing such deposits, accounts for the high summer flow, and provides water for irrigation and for power to pump the water.

The control of the Columbia River flow, in an effort to store at least a part of this tremendous volume of run-off in the summer, to be used later in the year during periods of lower River flow, is quite a problem. It involves international boundaries besides engineering skill. Grand Coulee backs the Columbia up to the Canadian border, and both of the main northern tributaries join the Columbia in Canada. However, both the Kootenai and the Clark Fork Rivers flow for many miles through the United States. The construction of Libby Dam on the Kootenai River in Montana has been authorized by Congress, and the construction of Hungry Horse Dam on the Clark Fork River and Albeni Dam on the Pend Oreille River has already started. The completion dates, the volume of water storage, predicted effect on river regulation, and installed generating capacities will be found later under Data.

The up-stream dams are very important in this study. Their effect on the regulation of the River is by no means negligible, and in the future it is possible that even more storage may be made available, the most probable being the Glacier View development. Since flooding is usually a minor problem on the Columbia, the main advantages in river regulation are, 1) reducing the volume of water that must be wasted each summer over the top of Coulee Dam and all the other projects on the main stem which are now completed, under construction, or in the planning stage, and 2) increasing the length of time of this surplus flow in the summer, and thus lengthen the time when power and water are available in ideal combination for pumping for irrigation.

The effect of river regulation is also very important in the justification of a third power house at Coulee, as this lengthened period of surplus flow would lengthen its period of possible operation at maximum capacity.

Roosevelt Lake: Coulee Dam was constructed 151 miles down the Columbia River from the Canadian border, yet this border determined the elevation of the dam. By international agreement, the river must not be backed up into Canada, limiting the maximum elevation of Lake Roosevelt to 1290 ft. This long, narrow lake has a capacity of nearly 10,000,000 acre ft., about half of which is active, and can be drawn down to supplement the natural flow of the river during the low water periods of the winter months. Lake Roosevelt is not used as a reservoir for irrigation water, as in the summer irrigation season, the river flow exceeds the needs of both power and irrigation. Lake Roosevelt is actually a relatively small reservoir on a very large river, and Grand Coulee Dam is considered a "run of the river" plant with pondage.

The lake level is maintained at an elevation of 1290 feet above sea level throughout the summer. After the peak flow, which usually occurs in June, the drum gates are gradually raised to maintain the reservoir level.

In the fall and winter months, the river flow is not sufficient to meet the power requirements, making it necessary to draw down the reservoir. The minimum reservoir elevation is 1,208 feet above sea level. The most critical period of high load and low water flow usually comes in the month of March, and the reservoir elevation has reached its minimum elevation at this time.

With the completion of the up-stream dams now under construction, the regulation of the Columbia River, to the extent that it can and will be regulated, will not be entirely in the hands of Coulee Dam as at present, and can be much more successful.

Northwest Power Pool: Since stream flows vary, and cannot be regulated completely by reservoirs, most water power plants vary in capacity from month to month. If many water power plants that have their high and low capacities at different times can be interconnected, they can help each other in times of need, and so can serve more people or industries. Through interconnections, they can use, in one place, energy which otherwise would go to waste as local surplus in some other place.

The Northwest Power Pool is a voluntary group of eleven private, municipal, and government power systems in Washington, Oregon, Idaho, Montana, and Utah. In it, a hundred and thirty private plants and twenty publicly owned plants are tied together, a total of 287 hydroelectric and 33 steam-electric units. The generating capacity is about 4,000,000 kw, 88 per cent hydroelectric, 11 per cent steam, and one per cent internal combustion. Operating details of mutual concern to members of the pool are handled by a coordinating committee.

Grand Coulee Dam: Although the river flow increases below Grand Coulee Dam as its tributaries meet it, none of the down-stream dams on the Columbia will approach Coulee in power capacity, because the fall there is greater than at any other site--25½ per cent of the total--and because a very large part of the total flow of the Columbia River originates above that point.

In each of the two power houses at Grand Coulee, are 9 generating units rated at 108,000 kw. However, over long periods they have carried continuous loads of 125,000 to 130,000 kw. Six of the nine large generators in the left powerhouse were designed for pumping duty. They differ from the others only in having their exciters motor-driven instead of the conventional built in type. The pump motors also have separate motor driven exciters.

Two pump motors are to be driven from one main generator. The generators driving pump motors may be connected to the station's 230,000 volt buses and synchronized to deliver surplus power when pumping conditions are favorable, or to receive power from the system during periods of low head on the turbines.

The pump motors can be started as synchronous motors or as induction motors, the main difference between the two methods being that, in the second case, motor-field excitation is not applied until the motors are synchronized with the generator. In both methods of starting, the rheostats in the fields of the generator's and motor's main exciters are pre-adjusted to the best position for starting.

Each of the main generator's turbines takes from 4000 to 5000 cfs of water at full load. This gives the 18 turbines a maximum capacity of about 90,000 cfs and an average requirement of about 75,000 cfs, indicating a relatively high load factor.

There has been considerable planning and speculation concerning a proposed third power-house. If such a power-house were built to house 6 units similar to the 18 already installed, the maximum water capacity would increase to 120,000 cfs, and the generating capacity from a present rated capacity of 1,974,000 kw to 2,622,000 kw. (13, pp. 1-13).

Feeder Canal and Equalizing Reservoir: The feeder canal is 50 ft. wide at the bottom and 125 ft. wide at the top, extending 1.78 miles from the pumping plant headworks to the equalizing reservoir. The canal is concrete lined, and will carry up to 16,000 cfs. It is of considerable interest in this study that the canal has quite a small drop over its entire length. The water is backed up into the upper end of the canal for approximately the last 15 ft. of elevation in filling the equalizing reservoir. This produces two significant effects. First, as the reservoir approaches its maximum capacity, the flow in the feeder canal becomes more and more restricted, until the canal can only carry the output of one pump for the last few feet of elevation in the reservoir. This means, that in leaving the reservoir in the full state - as might be desired in the fall for various reasons - the time element is involved, which might be important when the limited period of surplus water is considered. The second effect of the small slope of the feeder canal is that this makes it theoretically possible to use the canal in the reverse direction to carry the water back from the reservoir to the pump headworks, and reversibly through the outlet pipes which now become penstocks, through the pumps operating as turbines, and discharge into Roosevelt Lake.

The equalizing reservoir occupies the greater part of the floor of the Upper Grand Coulee. It will be 1 to 5 miles wide, 27 miles long and 27,000 acres in area. The total storage capacity is 1,202,000 acre-ft., with a 15 ft. draw-down. The equalizing reservoir cost less than 27 miles of concrete lined canal, and it provides valuable water storage space. Since the winter and spring flow in the river is ordinarily not sufficient to carry a full power load full time, water will not be available from the river for early irrigation. Water in the reservoir carried over from one summer's surplus can be used to start irrigation the next spring. It will also serve as a surge tank between the pumping plant and the irrigation system, making it unnecessary to synchronize pumping with the water demand, and permit pumping during off-peak periods.

Buses to the Pumping Plant: Normally, the six out of the nine generators in the left power house of Coulee Dam, which are designed for pumping duty, are connected to their 230,000 volt transformers through isolated phase buses provided with disconnect switches. A second set of similar buses, with disconnect switches near the generators, extends from generators through a gallery in the powerhouse, up the face of the dam, and through it to the pumping plant.

Pump Motors: The first two pump motors to be installed were built by General Electric Co. They are rated 65,000 hp at unity power factor, 3 phases, 60 cycle, 13,600 volts, 200 rpm. The additional 8 or 10 motors are being built by Westinghouse. The motors are rigidly attached to the vertical shaft pumps. The rotors are equipped with amortisseur windings which permit starting of the motors as induction motors.

The upper motor bracket carries one guide bearing and the thrust bearing, supporting the weight of all rotating parts and the unbalanced hydraulic thrust on the pump impeller. On the lower motor bracket is a second guide bearing and the rotor brakes.

Each motor is provided with air operated brakes which can be used also as hydraulic jacks to lift the rotating parts of the motor and pump for the purpose of removing or adjusting the thrust bearing. When the pump is being shut down, the motor speed diminishes to zero. Then the pump becomes a turbine, driven in reverse by the water draining out of its outlet pipe. The brakes are applied only after the motor has again slowed down at least to half speed. The above is of special interest, as it shows that the pumps operate at least reasonably well as turbines, and that the bearings were designed to operate for both directions of rotation.

Pumps: The single-stage, vertical shaft pumps were designed and furnished by the Byron-Jackson Company of Los Angeles and the Pelton Water Wheel Company of San Francisco, under a joint contract, and were built in the shops of the Pelton Water Wheel Co. They are rated at 1359 cfs at 310 ft. head, and deliver 1600 cfs under a 280 ft. head. The impeller is 13 ft., 11 in. in diameter. An accelerating elbow joins the 14 ft. intake pipe to the 7 ft. 6 in. eye of the pump, and a

3 degree diffuser, 61 ft. long, delivers water from the pump to the 12 ft. outlet pipe leading to the feeder canal above the pumping plant.

The pumps are set on 45 ft. centers, but the outlet pipes converge as they leave the pumps, and are 14 ft. 6 in. centers at the top of the lift where they enter concrete siphons which terminate in rectangular openings 12 ft. 4 in. wide, and 16 ft., 5 in. high, at the end of the feeder canal. Thirty inch siphon breakers are provided so that water will not be siphoned out of the canal when a pump stops.

The operation of the installed pumps to this time has not been entirely satisfactory. A harmonic frequency generated within the pumps has been found to resonate in the long outlet pipes leading up to the feeder canal, when the pump motors rotate at their 60 cycle synchronous speed of 200 rpm. The first pump had to be operated at 59 cycles for a considerable period while the outlet pipes were reinforced with steel rings. The Bureau engineers modified the vanes in the scroll case of the pump, and have felt that this has improved the condition to some extent. However, each of the 4 pumps installed to the time of this writing has been modified in a different manner, and it is a question whether any one of them has entirely eliminated the vibration noted in the first pump.

In the initial planning, 6 pumping units were to be installed at the present time, and 6 more as the need for irrigation water arose. The pumping plant and penstocks were constructed with this number in mind. However, this number has now been revised downward, at least tentatively, to 10 units, as the ultimate goal. Whatever the future plans, 6 pumps of the present type will soon be installed in the pumping plant. It must be noted, that the pumps are very similar to a conventional Francis type turbine, differing mainly in the absence of wicket gates. It has been indicated by Prof. Knapp of the California Institute of Technology, who worked with Byron-Jackson Co. on the design of the pumps, that these units could operate satisfactorily at approximately the same efficiency in either direction as pumps of turbines at rated speed. The hp rating of the units in the reverse direction would be considerably reduced, however. (8, pp. 39-44)

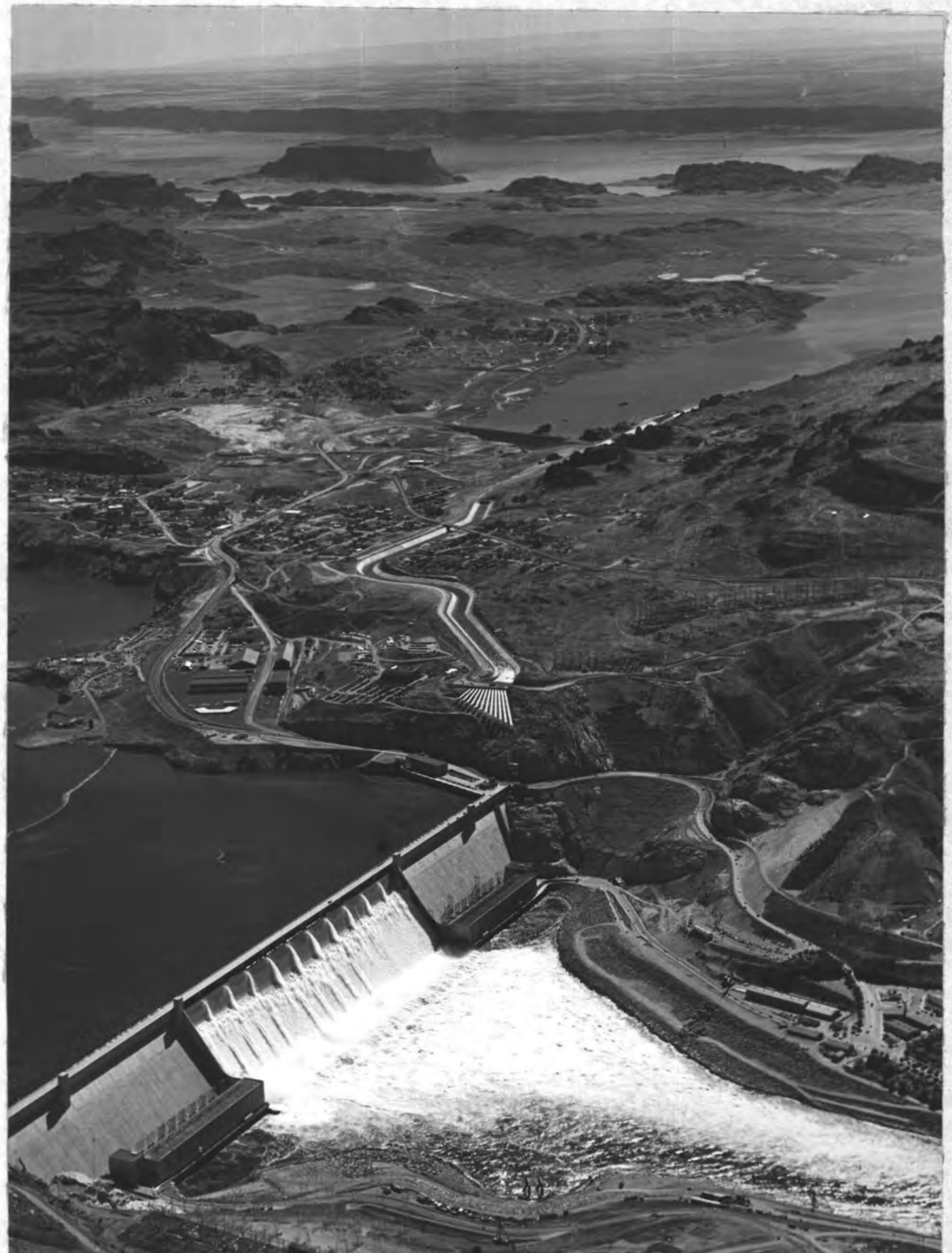
<u>Deviation of the Present Problem from the Ideal Case</u>. Due to the many deviations of the present problem considered from the Classical Pumped Storage problem discussed previously, the solution is considerably changed. These deviations are given below:

1) The Northwest Power Pool is essentially an all hydro system instead of a relatively evenly divided steam and hydro system or predominantly steam as is generally the case.

2) Further, the steam plants which are in the system, are small, inefficient, and located at a great distance from the proposed pumped-storage project. Since there is no apparent cheap source of fuel in the vicinity of this project, no new efficient steam plants of the necessary capacity are in prospect in the area.

3) Physical limitations:

a) The upper reservoir (Equalizing Reservoir) is connected to the pump outlets by a relatively long canal. This Feeder Canal limits the flow in both directions. This has the effect of making the

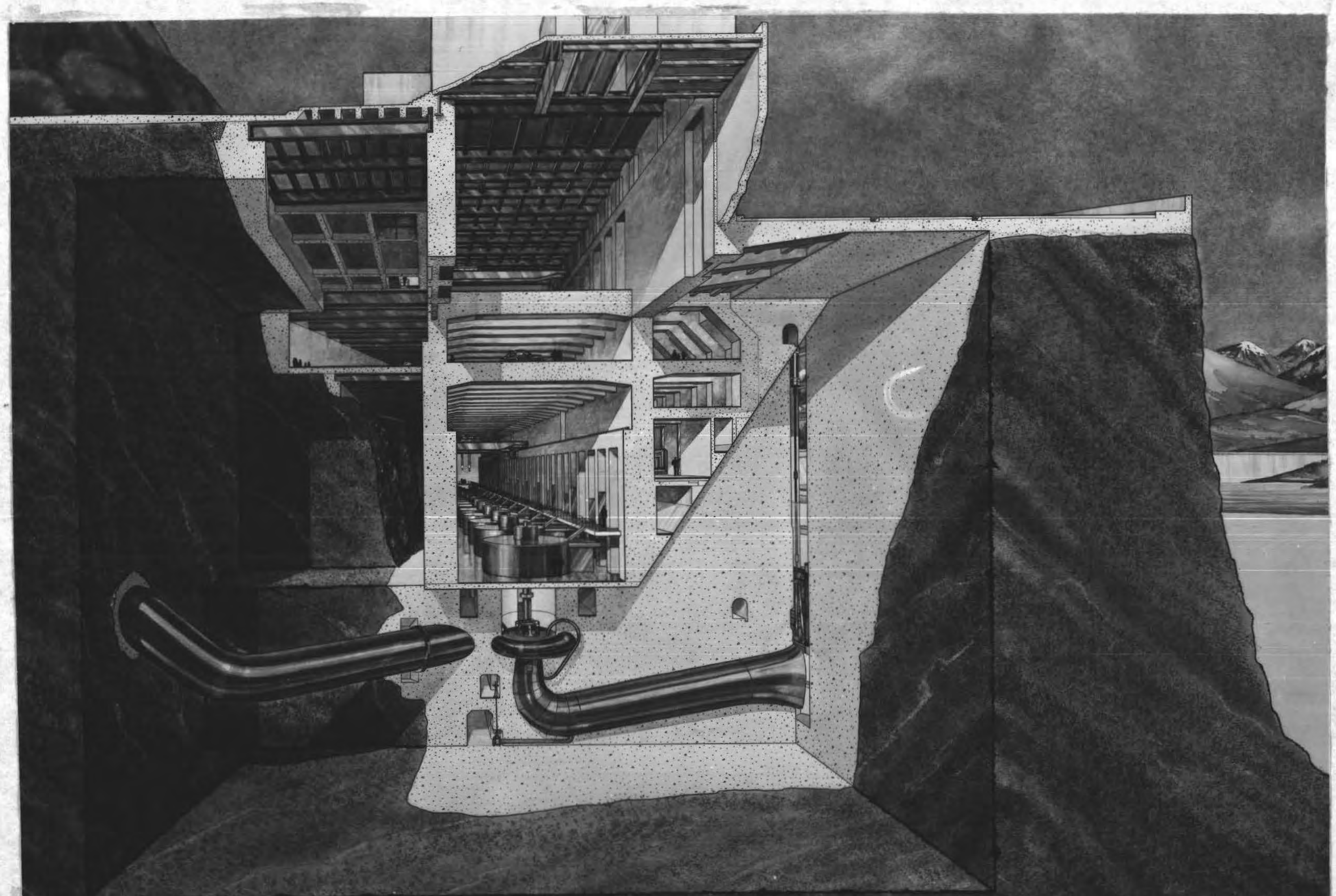


Grand Coulee Dam

Pumping Plant and Penstocks

The Feeder Canal and Equalizing Reservoir

Interior View of the Pumping Plant



GRAND COULEE PUMPING PLANT - SECTIONAL VIEW pumping very slow as the reservoir approaches the full point, and decreasing the possible reverse flow as the reservoir elevation goes down.

b) It is very fortuitous that the Feeder canal is of such a gentle slope that reverse flow is possible at all.

c) With the limited period of surplus water flow, and the slow pumping rate as the Equalizing Reservoir reaches its upper elevation, the problem of ending the pumping season with the reservoir full might be difficult or impossible in many years.

d) With the volume of reverse flow limited by the Feeder canal, the electrical capacity of the units operating reversibly as turbine-generators can be maximum for only the first few feet of reservoir draw-down, reducing gradually to zero at 15 feet of draw-down.

e) The pumping plant is already built. The pump wells for all twelve pumps are constructed to just contain pumps of the original design. Reversible units are usually of the wicket gate type, having a larger overall diameter for the same size impeller. A further discussion of this limitation is given in a summary of data received from the Baldwin-Lima-Hamilton Co.

The present installation has no valve arrangement suitable for governor action. The rectangular roller gate valves on the pump inlets could not function in this way. It might be possible to install a butterfly valve or Johnson valve to affect this control, if some of the present units were to be operated reversibly.

4) Joint use of the Equalizing Reservoir by the irrigation

people (who exert priority on water use) greatly modifies ideal storage from that which will actually be possible.

a) In many years, the surplus water period is not long enough to pump the irrigation water requirements from surplus water using secondary power or dump power. In these years, no water could be pumped from surplus water for pumped storage.

b) Fall irrigation draws down the Equalizing Reservoir, leaving considerable less storage than desirable. This storage is necessary for spring irrigation before the pumping period starts, so is definitely not without strings. In fact, from examination of the data, through the year 1961, the projected fall irrigation requirements always draw down the reservoir below the minimum level required for reverse flow through the Feeder Canal.

5) The projected Third Power-house at Coulee Dam would further reduce the actual surplus water periods. For the conditions of the River regulated by authorized up-stream dams, plus the third power-house, the necessary minimum of 139 pumping days per year is reduced to an average of about 60 days per year of surplus water.

6) Low power rates.

a) The value per kw-hr at Coulee Dam is very low (2.4 mills per kw-hr), due to the distance from the load centers, and the large percentage cost of transmission and distribution.

b) The low peak energy value at Coulee Dam. The price differential between firm power and peak power at Coulee is considered to be almost non-existent. This may be partly an artificial situation created by a Governmental agency. However, it is at least in part a reflection of 7 a), the low percentage cost of actual generation.

This is a very important point, as it largely destroys the economic advantage usually enjoyed by peak load plants.

7) Coulee Dam is essentially a base load plant. The load factor of Coulee is high (between 75 and 80 per cent). This means that periods of surplus energy are short, leaving inadequate ideal pumping periods. In the summer, irrigation water pumping takes priority over secondary energy. Any pumping in the fall or winter which might be considered in connection with pumped-storage for the reservoir build-up, would have to be considered very carefully so as to determine the most efficient use of the water involved.

8) Secondary energy has a very high load factor (approximately 90% or better) due to the type of industry involved. Thus, there is really almost no "dump" power available for <u>free</u> pumping, even in the summer periods of maximum runoff.

9) The type of power shortage involved is not exactly the type usually considered. In the Northwest Power Pool, there are two different basic causes for power shortages. The first type of shortage is due to the seasonal low river flow which occurs annually in the months of January, February, and March, usually becoming most severe in March. This water shortage is due to the freezing of the river tributaries and the melting in the Canadian ice fields reducing to almost zero. This type of power shortage can be handled by a suitable peak-load plant.

The second, and more serious, type of power shortage is caused by the cyclic reoccurrence of low-water years, producing a shortage that lasts for many months - possibly an entire fall and winter. No peak plant can satisfactorily solve this problem. What it needs here, is an installed capacity completely independent of river flow, as only steam plants can be.

10) The elevation of Lake Roosevelt (the reverse flow outlet and pump inlet) varies considerably from season to season. This could be an advantage in added head for reverse flow for pumped storage on a yearly basis, or disadvantage for pumping under some conditions.

One major consideration is the effect it has on reversible unit efficiency and rating. Specially designed reversible pump-turbines with wicket gates can operate very successfully over a range of elevations (variation in head). However, standard pump units with no wicket gates, as the presently installed pumps, would suffer considerably in their reverse performance.

11) As noted previously, the specially designed reversible units are more flexible, giving a higher efficiency over a range of head variation. Six of the pumps of the original design are being presently installed, and it is very unlikely that an exchange of these units could be considered. That means that any units of the pump-turbine type would have to be installed later, in the places provided for the 4 or 6 remaining pumps to be installed in the pumping station. It is not expected that these additional pumps will be required to meet irrigation needs for several years.

Pumped Storage on a Yearly Basis. In the ideal case, the method of yearly pumped storage, in an all hydro system, is theoretically the best. In this method, the large upper reservoir would be filled in the summer during surplus water periods, using cheap secondary or dump power. This water would be free - that is, it is not limiting the capability of any plant on the river, or postponing the output. It represents additional storage in the system. This storage is released during the winter in periods of peak load and low river flow, producing the immediate desired effect in generating needed energy, and in addition, a much greater and very significant net energy gain as the water proceeds down stream through each of the many down-stream dams.

The yearly pumped storage plan is superior in an all-hydro system, because the storage represents additional storage instead of just a transfer of storage. Also, in the ideal condition, the pumping could be done during surplus water while there was dump power available.

Pumped Storage on a Daily Basis. A system of daily pumping and return is used in all of the pumped-storage plants studied. Usually the storage reservoir is limited in size, as is the quantity of water available. This is the classical case in which the water is pumped up into the reservoir at night during low load periods, using cheap off-peak steam generated energy, increasing the load factor of these plants. During the daily peak load period, the water is returned through the turbines to the lower reservoir to fill a need for high cost peak power. Since no steam plants capable of furnishing cheap off-peak power are presently available, or even in prospect within a reasonable radius, this problem will be considered on a strictly hydro basis. In this, the water would be pumped up into the upper reservoir using off-peak hydro energy, and returned during periods of peak load the following day.

A steam plant can increase its over-all efficiency by increasing its load factor. This is not true to at all the same extent for a hydro plant. Thus, one major advantage of pumped storage is lost. The important thing which can be gained is increase in generating capacity to handle the peak load periods.

In the system which has a combination of steam and hydro capacity, the problem is one of just dollars and cents economy. Energy is brought into the system from some outside source, such as coal or oil, at a certain cost, to be released at some later time at a greater price. Even in the all-hydro system somewhat the same condition exists during periods of surplus water flow, as the pumping can be done with either cheap secondary power or dump power. However, in a system in which the river flow, at the time of the use of the pumped storage operation, is never in excess of the energy and storage requirements of the system over a 24 hr. period, the problem becomes more complicated. Here, the most efficient use of the water may be the limiting factor. Economy of water and in cost are both involved, and their relative importance may be different in each individual problem.

In a consideration of the effect of the daily pumped storage schedule, the over-all effect on the stream flow over a 24 hour period would be zero. The projected pumping schedule which the Bureau intends to follow, calls for the Equalizing Reservoir to be full at the end of the surplus water period in August. The reservoir is drawn down during September and October, leaving sufficient water in the reservoir over the winter for spring irrigation before surplus water periods in May or June. This schedule would not need to be changed if the daily pumped storage solution were used. This assumes that sufficient water remains in the reservoir after the fall irrigation to allow back-flow through the feeder canal. However, the elevation of the water in the Equalizing Reservoir controls the back-flow capacity, and thus controls the available capacity for reverse operation at any given elevation.

Pumped Storage vs. Direct Use of Water by Main Stem Plants.

As indicated in the previous section, in a power system which is predominately hydroelectric, the problem of water efficiency must be considered in any study of pumped-storage. Water storage behind the main stem dams is a very critical and expensive commodity. The seasonal storage and release of the water is a continual and involved problem, the objective being the obtaining of maximum energy possible from available resources; the planned release of this storage in such a manner as to obtain the maximum firm power throughout the year. This plan may need to be modified to meet flood control and irrigational requirements. Any water storage or water release plans must be consistent with the need of all the down-stream dams.

Until recently, Grand Coulee Dam was the uppermost major dam on the Columbia and tributaries. Hungry Horse and Albeni Dams are under construction and will be completed in 1953 and 1954 and are very valuable as storage reservoirs above Coulee. Any additional storage increases the firm power of the system. If a system of pumped storage can increase the storage of the system, a real advantage would be gained. However, to achieve this, water must be stored (in the Equalizing Reservoir) which could not be stored otherwise at this river elevation. In other words, to obtain additional storage, pumping must be done for pumped-storage during surplus water periods at Grand Coulee. This may or may not be possible, depending on river flow, pumping capacity, and irrigation requirements. We assume that during periods of surplus water, a sufficient surplus to generate power to pump <u>with</u> and to pump from.

If additional storage is provided the water released would be valuable, and any energy derived during its reserve flow cycle at the pumped-storage plant, at Coulee Dam, and at all of the down stream plants would represent additional energy in the system not otherwise obtained. This is the ideal case.

The other alternative, of having to pump from water which is not surplus, may be very probable, and is rather more complicated and less attractive. This includes three separate possibilities:

(a) Pumping from present storage using off peak steam energy. This is the usual case in existing pumped-storage plants. Here, an economic advantage may be gained, but the resultant amount of water storage is the same. Peak power is provided and thus an increase in firm power, but a lesser increase than previously discussed, due to no increase in water passing the down stream dams.

The economic implication of this alternative will not be discussed at this point, but it will be noted that there are, at present, no new efficient steam plants in the Northwest, and none at all near Coulee.

(b) Pumping from present storage using surplus hydro power from some down-stream dam having a lesser water capacity and storage than Grand Coulee. Bonneville, McNary and Chief Joseph dams are run-of-the-river dams. While none of these may have an average flow exceeding their maximum water requirements later in the year than Grand Coulee, in daily low-load periods they may spill much later than Coulee due to lack of storage. This energy could be shuttled around in the Power Pool and utilized in pumping at Coulee. This plan is as efficient from a water standpoint, as using steam energy as in (a). From a dollars standpoint it is more advantageous than (a).

(c) Pumping from present storage, using water and hydro energy which is <u>not</u> surplus. If the irrigating season is longer than the surplus water season, and if no steam or surplus hydro energy is available, this would be the only alternative. The losses in energy caused by the inefficiency of the hydraulic and electrical components of the system will reduce the net energy output from that obtained in using only the main stem generating units. The only advantage of using this type of pumped storage is in gained peaking capacity. However, the energy sacrifice to obtain the capacity makes a choice necessary, based on the greatest need of the system. The hydro plants on the Columbia have a tremendous installed capacity, limited mainly by available river flow. Added capacity will probably not be the major problem.

<u>The True Cost of Peak Energy</u>.

Cost Structure Complexity. It is recognized that the cost structure in electricity supply is extremely complex: there are, for instance, costs which are most directly related to the number of consumers supplied, those which vary mainly with the amount of energy supplied, and those associated with the size of the supply system--plant capacity costs. To translate these types of cost strictly into tariffs so devised that each consumer would be charged just those costs for which he could be held responsible would be neither practicable nor economic. It is considered, however, that as far as is practicable and economic, the tariffs should reflect the plant capacity costs. Reasons given for this are that in recent years shortage of plant capacity has led to load spreading and shedding at considerable real cost to the community, and the high cost of plant capacity both absolutely and in relation to total costs of electricity supply make it important that tariffs should encourage the economic use of electricity plant by full reflection of its costs.

As costs of plant capacity are related mainly to the peak load on the system, if prices are fully to reflect these capacity costs, electricity tariffs should differentiate between charges for use during system peak hours and charges for use at off-peak hours.

The most usual tariffs for supplies to large commercial users include a standing charge related to some index of the maximum demand which the individual consumer may make at any time--there is no differentiation between charges for supplies during the system's peak and off-peak hours. Similarly, the normal tariff for large-scale industrial use includes a charge related to the maximum demand which the consumer actually makes at any time. Here also, there is normally no difference in charge between maximum demand during system peak hours, which form a large part of the working day, so that this failure to differentiate between peak and off-peak use is less serious, and some industrial tariffs incorporate specially reduced charges for maximum demands made at night.

Off-Peak Differentiation. Differentiation between charges for peak and for off-peak use might be made either by measuring the electricity taken by the consumer during certain specified hours when load shedding is imminent and making a charge for it sufficiently high to cover plant capacity costs, or by limiting the load the consumer can switch on at those times to some maximum demand for which he has chosen to pay.

Surplus Electricity Purchase. The Committee also considers that the same principles should be applied by the Electricity Boards in their terms for the purchase of surplus electricity from firms with their own generating plant. Appropriate buying prices would correspond to the reduction in the Board's own expenditures as a result of their buying electricity from the industrialists; at off-peak hours this would mainly be the Board's coal cost, but at peak hours should include also capacity costs, in so far as the supply was then regularly available to reduce the Board's own demands on power station capacity, or while there is a general shortage of capacity, to avoid the necessity of spreading or shedding load (6, pp.749-751).

<u>Pumped Storage Hydroelectric Plant Construction to Replace Old Steam Plants. Economic Considerations.</u>

Although the cost of hydroelectric projects is usually 2 to 2.5 times that of steam plants, a large part of the cost is in dams, lands, reservoirs and riparian rights. The incremental capital cost is frequently between \$55 and \$70 per kw. This includes only that part of the cost which is roughly proportional to the installation.

In many systems, pumped storage hydroelectric plants may prove economical as competitors for that portion of the annual load curve now served by the older steam plants having a high operation cost and a low annual capacity factor. Many such plants are remaining in service as reserve capacity and to carry the peaks of the annual load. It will not usually be economically advisable to supersede an old steam plant with such a pumped storage hydro plant unless the total annual cost of the pumped storage plant including fixed charges is less than operating cost plus taxes, insurance and annual cost of renewals and replacements for the old steam plant.

An example will be given to illustrate the problem. Assume an old steam plant having a fixed operating cost of \$11 per kw and the marginal cost of energy produced by it is 5 mills per kw-hr. Taxes and insurance on the old steam plant will be assumed at \$2.50 per kw and renewals and replacements at \$2.00 per kw. Ten per cent on capital cost will be assumed as the total annual cost of the pumped storage hydro plant which might supersede the old plant, this to exclude the energy purchased for pumping. The maximum permissible capital cost of the new pumped storage plant would then be:

$$\frac{\$11 + \$2.50 + \$2.00}{10\%} = \frac{\$15.50}{.10} = \$155 \text{ per kw}$$

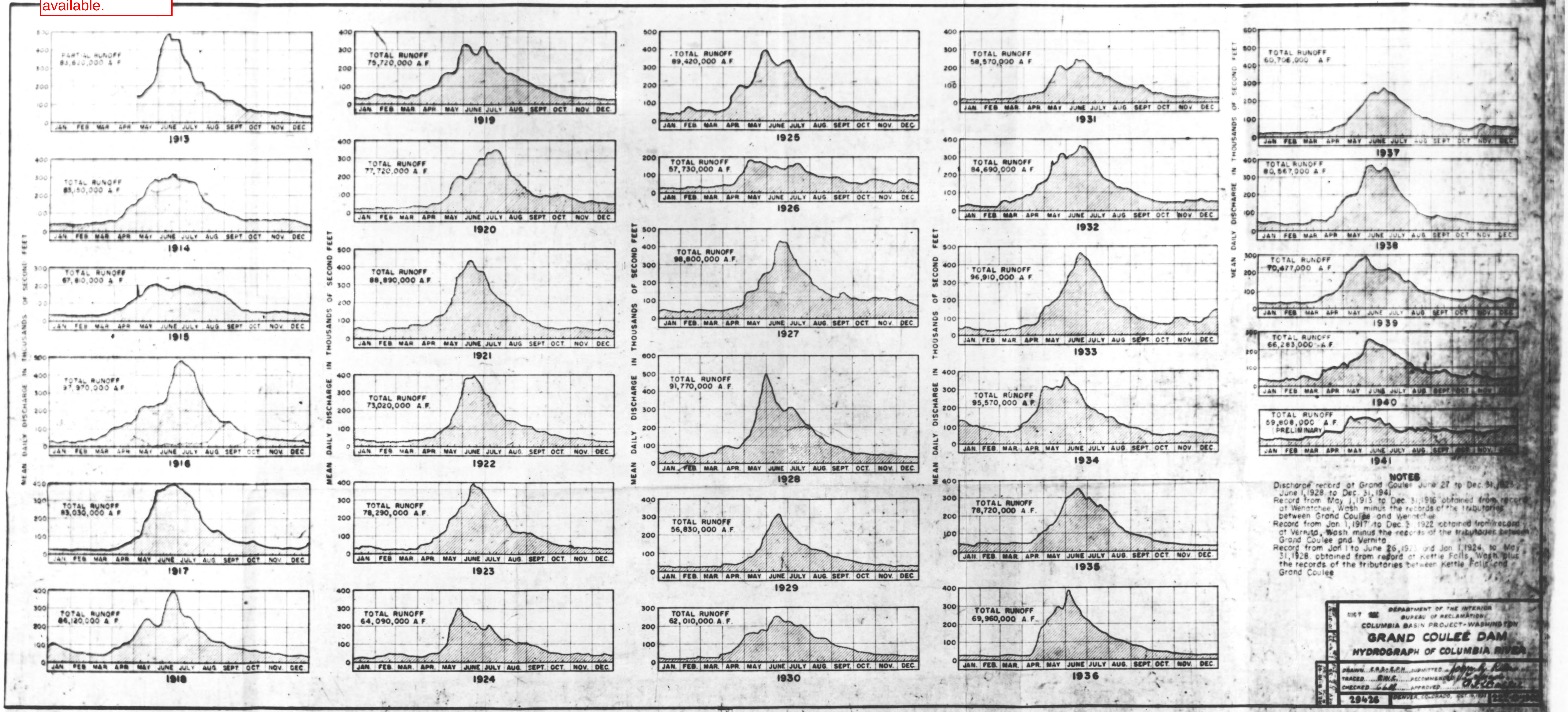
If the overall efficiency of the pumped storage plant from energy purchased for pumping to energy delivered by the plant were 65% (as at Rocky River Plant), the maximum permissible price for purchased energy would be: 5 mills per kw-hr x 65% = 3.25 mills per kw-hr, in order to make the annual cost of the two plants identical.

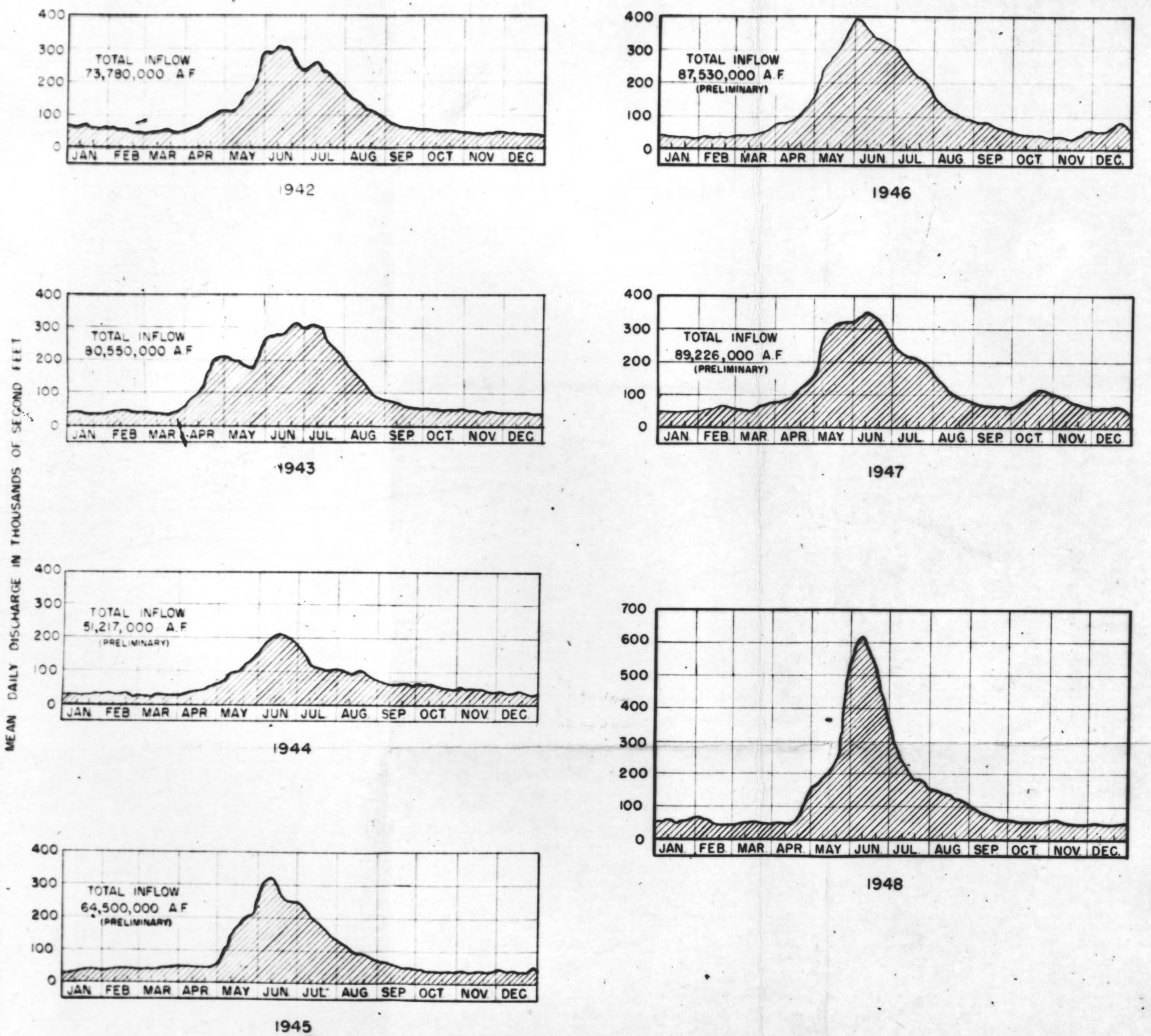
In other words, in the above case a pumped storage plant producing the same amount of energy per year as the old steam plant would produce power and energy at a total cost equal to the cost at the old steam plant, excluding return on the investment, if the capital cost of the pumped storage plant was $155 per kw and off peak energy for pumping cost 3.25 mills per kw-hr. (9, p.193-194).

DATA.

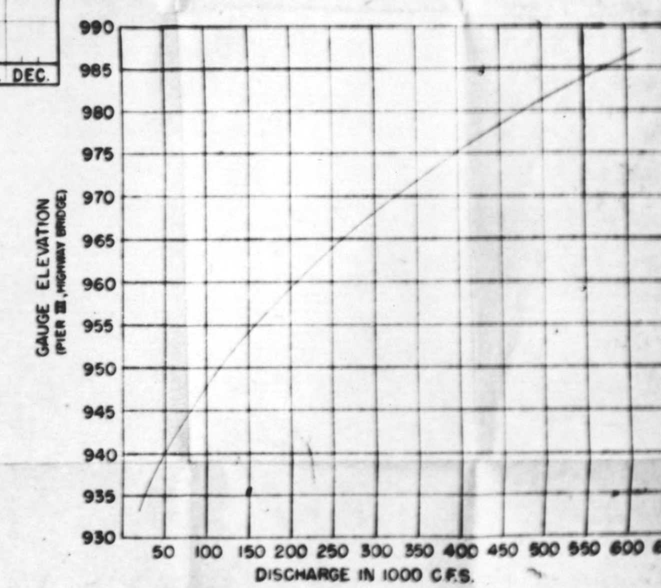
Columbia River Flow Characteristics at Grand Coulee Dam, River Unregulated. The following curves include all of the available actual flow data for the Columbia River at Grand Coulee, through the years 1914-1949.

Best scan available.





HYDROGRAPH



DISCHARGE RATING CURVE

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF RECLAMATION
COLUMBIA BASIN PROJECT-WASHINGTON
GRAND COULEE DAM
COLUMBIA RIVER
HYDROGRAPH AND DISCHARGE RATING CURVE

REVISED 6-5-1950 COULEE DAM, WN.
REV. 9-21-49 DENVER, COLO.

DRAWN. R.M.D. SUBMITTED. [signature]
TRACED. R.M.D., J.H.B. RECOMMENDED. W. H. Nalder
CHECKED. G.I.D. APPROVED. [signature]

222-P-5490 COULEE DAM, WASH. OCT. 13, 1948 222-D-13373

<u>Columbia River Flow Characteristics at Grand Coulee, River Regulated to Phase C</u>. Curves, showing the predicted Columbia River flow curves, as they might have been, through the years 1927 to 1942, if the river had been regulated to Phase C are given next in the Data. Since the Phase C regulation for the river has been superceded by the Phase C-2 plan for river regulation, excerpts from a letter received from the Corps of Engineers, U. S. Army, are included, which indicate the necessary adjustment required for the curves to be converted from Phase C to Phase C-2. It appears that the difference is relatively small, requiring only a 2000 cfs change. This is practically negligible, which means that the curves can be used as they are for Phase C-2 operation.

The included curve of this data is taken from the Table 31 in Appendix O of the Army Engineers 308 Report on the Columbia River, and is plotted in the curve labeled Chart 38.

Curves showing the Power Capability, Power Plant Characteristics, and Load Duration Curve for Grand Coulee Dam for Phase C river regulation are included.

CORPS OF ENGINEERS, U.S. ARMY
Office of the Division Engineer
North Pacific Division

500 Pittock Block
Portland 5, Oregon

C O P Y

July 23, 1952

Mr. Jerome H. Johnson
Washington State College
Department of Electrical Engineering
Pullman, Washington

Dear Mr. Johnson:

. . . . . Perhaps table 31 of Appendix O may provide you with information that you may find useful in your proposed study. This table contains data for a theoretical operation of the Phase C system which has a combination of storage and run-of-river projects over a 15-year period. The final system of reservoirs (Phase C-2) that was recommended for authorization by the Corps differs essentially from the Phase C system only in substituting the Libby Project on the Kootenai River for the Paradise project on the Clark Fork River. Both systems consider the Glacier View storage which was not recommended but which equivalent storage must be provided for in order to insure a balanced multiple purpose development of the region. Elimination of the Glacier View storage and substitution of Libby storage in lieu of the Paradise storage would probably have a net effect of reducing the flows past Grand Coulee on an average not more than 2,000 c.f.s. with respect to flows shown on pages O-243 and O-244 of table 31. . . . .

FOR THE DIVISION ENGINEER:

Yours very truly,

DEPARTMENT OF THE ARMY — CORPS OF ENGINEERS

LEGEND

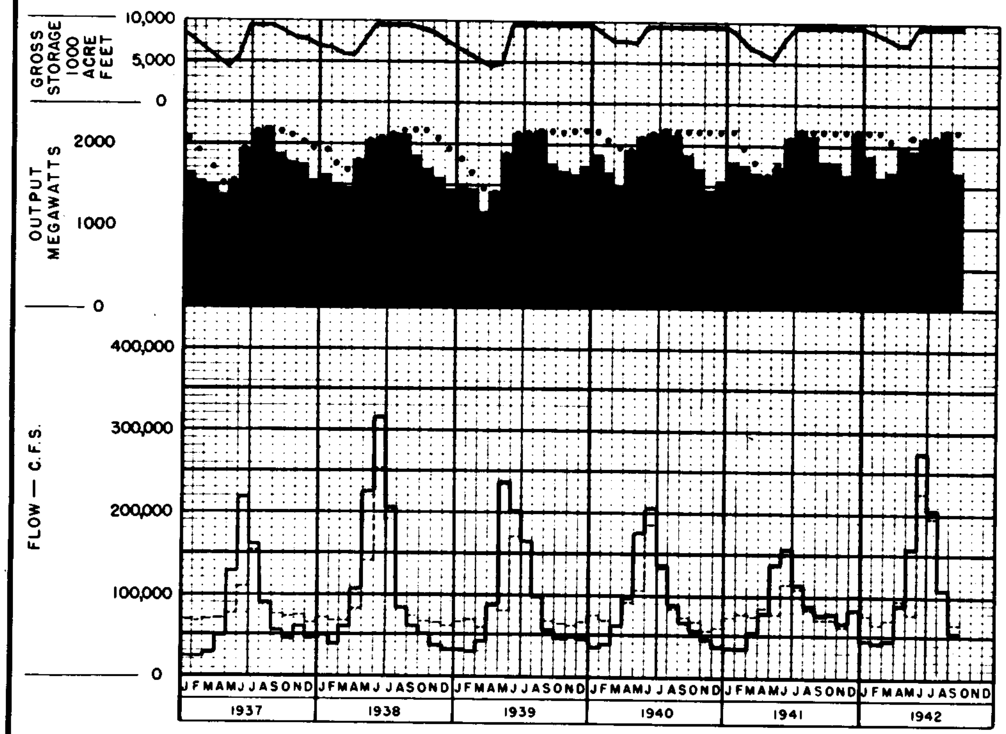
NATURAL "Q"

REGULATED "Q"

ACRE FEET OF STORAGE IN RESERVOIR (GROSS) TO ILLUSTRATE RESERVOIR LEVEL.

••• PEAKING CAPABILITY. AVERAGE MONTHLY.

POWER OUTPUT. AVERAGE MONTHLY.



NOTES

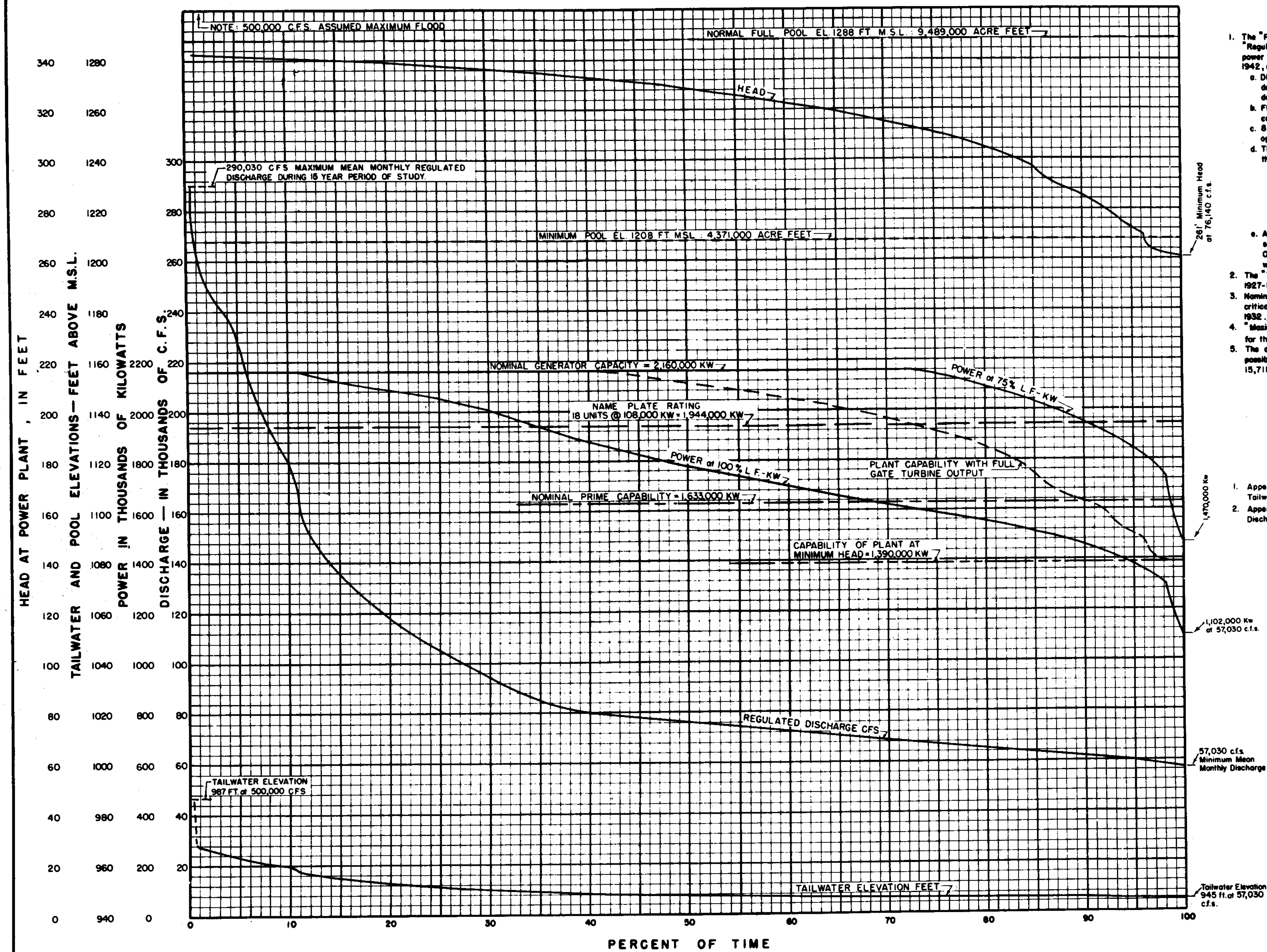
1. INSTALLED CAPACITY (NAME PLATE RATING) 18 UNITS AT 108,000 KW= 1,944,000 KW.
2. PLOTTED DATA TAKEN FROM APPENDIX D TABLE 31 "SYSTEM POWER STUDY, PHASE C MAJOR PROJECTS (1927-1942)", SHEETS 9 AND 10
3. PEAKING CAPABILITY ASSUMED LIMITED TO 2,160,000 KW (18 UNITS) IS SHOWN FOR MONTHLY AVERAGE HEAD CONDITIONS.
4. MANDATORY FLOOD CONTROL STORAGE REQUIREMENTS ARE SUBJECT TO ANNUAL VARIATIONS. SEE APPENDIX O CHART 13 FOR RESERVOIR DRAWDOWN.
5. PLANT CHARACTERISTICS ARE SHOWN ON CHART 20.

COLUMBIA RIVER AND TRIBUTARIES
GRAND COULEE
POWER CAPABILITIES, DISCHARGE, AND STORAGE
PHASE C DEVELOPMENT
1927-1942

In 1 Sheet — Scale: As Shown
Seattle District, Seattle, Washington — October 1, 1948

Prepared: Senior Engineer — Submitted: H.W. Goodhue, Chief, Major Projects Plan. Sec.
Recommended: J. M. Buswell, Chief, Civil Works Br. — Approved: Chief, Engineering Div.

Drawn by: CDS
Traced by: GBE
Checked by: RWL
Transmitted with report dated October 1, 1948
File No. L-11-7-38



1. The "Power at 100 percent load factor" curve and the "Regulated discharge" curve are based on the Phase "C" system power study for the period October 1927 through September 1942, under the following conditions:
   a. Discharges modified by future irrigation for initial development in Snake River Basin and for ultimate development elsewhere.
   b. Flathead Lake, regulated for a minimum draft of 4,300 cubic feet per second.
   c. 817,000 Acre-feet of existing storage in Kootenay Lake operated in its own interest.
   d. The following usable storage operated for the benefit of the system:

Hungry Horse	2,980,000 acre-feet
Glacier View	3,160,000 " "
Paradise	4,080,000 " "
Albeni Falls	1,140,000 " "
Grand Coulee	5,118,000 " "
Hells Canyon	3,280,000 " "

   e. A deduction of 500 cubic feet per second at the site for leakage, fish migration, and miscellaneous uses. Over-all plant efficiency is 87 percent at rated net head, with assumed reductions at other heads.
2. The "Tailwater" curve is based on system operation for the 1927-1942 period. See reference No. 1.
3. Nominal prime capability is the average output for the 23 critical months in the period October 1929 through February 1932. See reference No. 2.
4. "Maximum assumed flood" approximates the maximum flood for the 1927-1942 period.
5. The average annual output for the 15 year study period possible within limitations of installed generator capacity is 15,711,000 M W H.

REFERENCES

1. Appendix O Chart 20 "Grand Coulee Dam Storage, Tailwater and Power."
2. Appendix O Chart 38 "Grand Coulee Dam Power Capabilities, Discharge and Storage."

COLUMBIA RIVER AND TRIBUTARIES
GRAND COULEE
POWER PLANT CHARACTERISTICS
PHASE C DEVELOPMENT

In 1 Sheet — Scale: As Shown
Seattle District, Seattle, Washington October 1, 1948

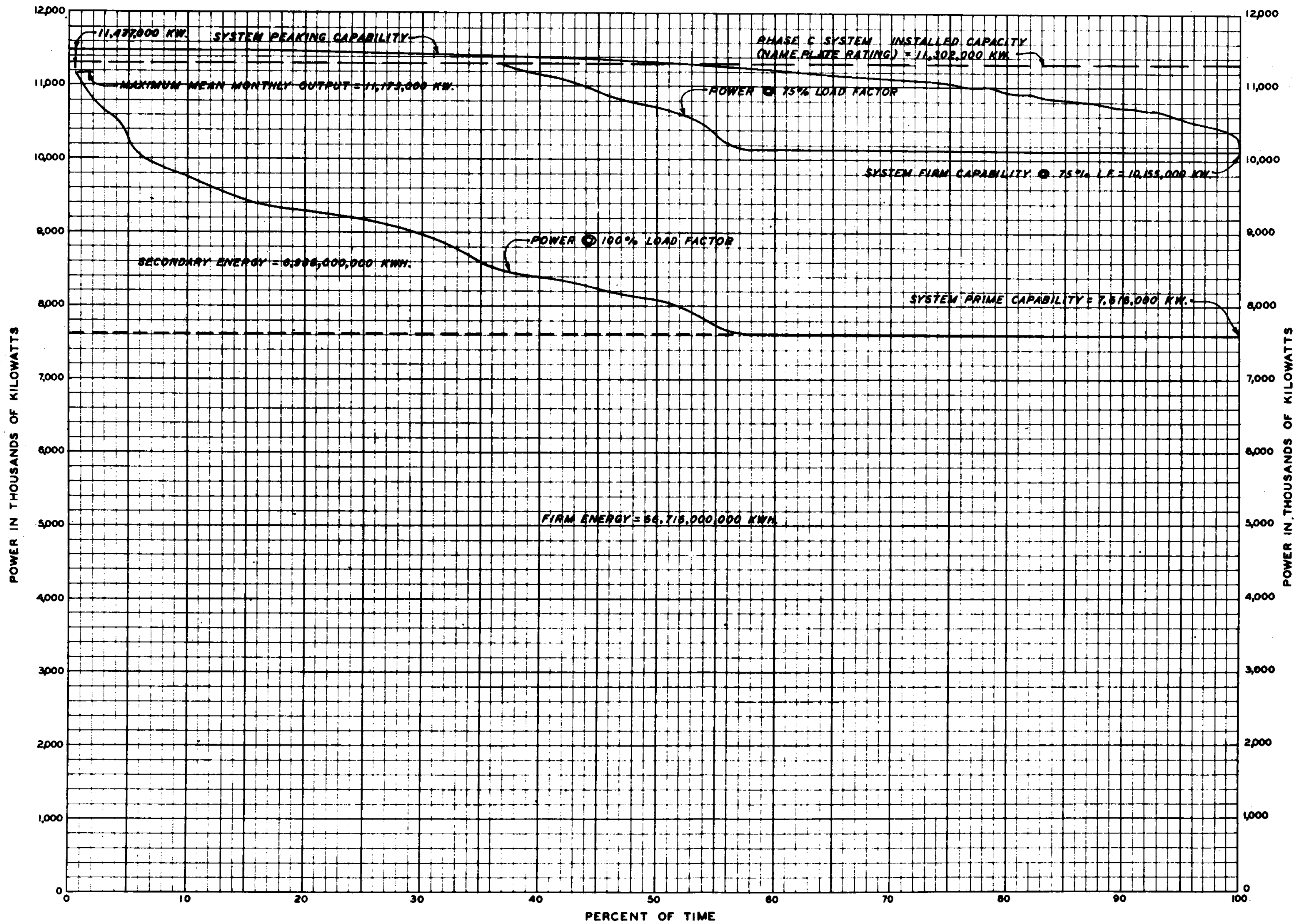
Prepared: Senior Engineer — Submitted: H.W. Goodhue, Chief, Major Projects Planning Sec.
Recommended: J. M. Buswell, Chief, Civil Works Br. — Approved: E.L. [illegible], Chief, Engineering Div.

Drawn: RWL
Traced: G.B.E.
Checked: CDS

Transmitted with report dated October 1, 1948 — File No. L-11-7-36

APPENDIX O PLATE 8

DEPARTMENT OF THE ARMY CORPS OF ENGINEERS



1. The system shown hereon includes Phase C Major Projects and the Willamette Basin Projects. The nine Upper Snake River Basin Projects (U.S. Bureau of Reclamation proposed total installed capacity = 268,000 kw.) are not included because of the lack of detailed data on them for the period of record studied (1927-1942).
2. The "power at 100% load factor" and the "system peaking capability" curves are plotted from data taken from Tables 34 and 35 respectively of Appendix O. Also see Chart 8, Appendix O which is a graphic presentation of the data tabulated in the two tables referred to above.
3. The installed capacity (11,302,000 kw.) includes 10,915,000 kw at Phase C Major Projects and 387,000 kw. at the eight Willamette Basin Projects.
4. The system prime capability is the summation of the nominal prime capabilities of Phase C Major Projects (7,480,000 kw.) and the Willamette Basin Projects (136,000 kw.).
5. The system theoretical maximum peaking capacity, on the basis of assumptions adopted for the power studies = 11,570,000 kw. = 11,302,000 kw. + overload capacities of 52,000 kw. and 216,000 kw. at Bonneville and Grand Coulee respectively.
6. Average annual energy production equals 73,704,000,000 kw. hrs.

COLUMBIA RIVER AND TRIBUTARIES

PHASE C SYSTEM

POWER DURATION

In 1 Sheet — Scale: As Shown
North Pacific Division, Portland, Oregon — October 1, 1948

Recommended: Ben L. Peterson, Chief, Flood Control Branch
Approved, for the Division Engineer: Benjamin R. Wood, Chief, Engineering Division

Drawn by: W.F. Traced by: R.V.W. Checked by: K.G.T.
Transmitted with report dated October 1, 1948
Portland District File No. CL-05-9/2

Dams Upstream to Grand Coulee Dam, Under Construction, Authorized, and Planned (Projected Completion Dates, Rating, Location, and Storage).

Name	Location	Rating	Completion Date	Storage
Cabinet Gorge	Clark Fork River	50,000 kw 50,000 50,000 50,000 200,000 kw	1952 1952 1952 1953	Dead Storage
Hungry Horse	South Fork Flathead	72,250 kw 72,250 72,250 72,250 289,000 kw	1952 1952 1953 1953	2,980,000 acre-ft
Albeni Falls	Pend Oreille River	14,000 kw 14,000 14,000 42,000 kw	1954 1954 1954	1,140,000 acre-ft
Libby	Kootenai River	588,000 kw total	Authorized but not appropriated for.	4,250,000 acre-ft
Glacier View	North Fork Flathead River	210,000 kw total	Not authorized	3,160,000 acre-ft

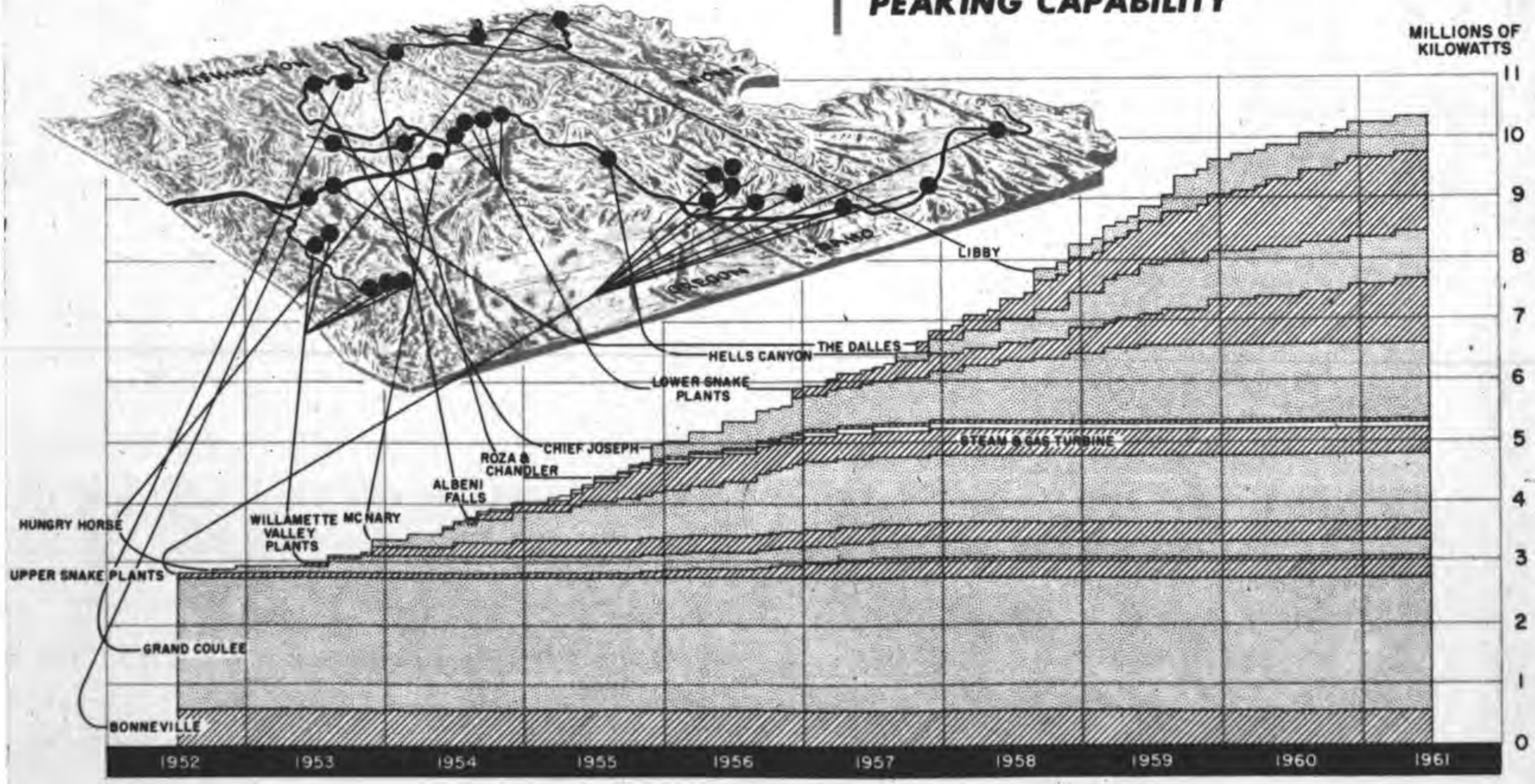
With the exception of Cabinet Gorge Dam, these are all Federal projects. Cabinet Gorge is a Washington Water Power Plant.

It might be mentioned that both of the large Columbia River plants downstream from Grand Coulee Dam, are essentially run-of-the-river plants with only dead storage. The generating units will be installed in McNary Dam 1953 through 1955. The generating units will be installed in Chief Joseph Dam in 1955, according to present plans.

CHART 1

GENERATOR INSTALLATIONS

SCHEDULE OF GENERATOR INSTALLATIONS U.S. COLUMBIA RIVER POWER SYSTEM DEFENSE PROGRAM SCHEDULE U PEAKING CAPABILITY



Phase C-2 of Columbia River Development and Regulation. Excerpts from "Review Report on Columbia River and Tributaries, Appendix O, Power Generation and Transmission" (3, pp.52-65).

Levels of power development studied. The development of water resources in the Columbia Basin is examined in a series of stages or levels each of which constitutes an advance toward the complete regulation of Columbia River flows. The study of power development observes these same levels which are designated as Phases A, B, C, C-2, D, and E, and is confined to an analysis of the Federal projects concerned.

Phase A system. The Phase A level of development comprises only the existing Bonneville and Grand Coulee power plants.

Project	River	Usable storage, acre-feet	No. units	Installed capacity, kilowatts
Bonneville	Columbia	pondage	10	518,400
Grand Coulee	Columbia	5,118,000	18	1,944,000
Total		5,118,000		2,462,400

Phase B system. The Phase B level of system development includes, in addition to the two Phase A Federal projects, the following authorized projects.

Project[1]	River	Usable storage, acre-feet	No. units	Installed capacity, kilowatts (nameplate)
Bonneville	Columbia	pondage	10	518,400
Grand Coulee	Columbia	5,118,000	18	1,944,000
Hungry Horse[2]	South Fork Flathead	2,980,000	4	300,000
Foster Creek	Columbia	pondage	16	1,024,000
McNary	Columbia	pondage	12	840,000
Lower Snake[3]	Snake	pondage	12	735,000
Totals		8,098,000		5,361,400

[1]See table 21 on page O-223 for basic data.
[2]U. S. Bureau of Reclamation
[3]Development consists of four dams.

<u>Phase C system</u>. The primary criterion in selecting the Phase C system of Federal generating station was that it should be able to meet all requirements of approximately a 10,000,000 kilowatt peak load, which was a preliminary estimate by the Bonneville Power Administration of the approximate peak load which could be expected in the Federal system by 1960 under conditions reasonably favorable for its growth. The Phase C power system was selected by the Corps of Engineers as representing that group of most economically feasible power projects which would not only meet this load requirement, but would satisfy, in conjunction with other non-power developments, the major other multiple-purpose needs of the Basin including flood control, navigation, and irrigation.

The following tabulation summarizes the storage and installed capacities at each project under the Phase C stage of system development.

Project[1]	River	Usable storage, acre-feet	No. units	Installed capacity, kilowatts (nameplate)
Bonneville	Columbia	pondage	10	518,400
Grand Coulee	Columbia	5,118,000	18	1,944,000
Hungry Horse	South Fork Flathead	2,980,000	4	300,000
Foster Creek	Columbia	pondage	20	1,280,000
McNary	Columbia	pondage	13	910,000
Lower Snake	Snake	pondage	16	980,000
Glacier View	North Fork Flathead	3,160,000	3	210,000
Paradise	Clark Fork	4,080,000	8	576,000
Albeni Falls	Pend Oreille	1,140,000	3	42,600
Priest Rapids	Columbia	pondage	23	1,219,000
John Day	Columbia	pondage	13	1,105,000
The Dalles	Columbia	pondage	14	980,000
Hells Canyon	Snake	3,280,000	10	850,000
Subtotal, major projects		19,758,000		10,915,000
Willamette Basin[2]	Willamette	--	--	387,000
Upper Snake[3]	Snake	--	--	268,000
Total		19,758,000		11,570,000
Total added by Phase C major projects		11,660,000		5,554,000

[1]See table 21 on page O-223 for basic data.
[2]Eight plants.
[3]Nine plants, U. S. Bureau of Reclamation.

Phase C-2 or recommended power system. When local opposition to the Paradise project mounted to the point that the project, on Kootenai River near Libby, Mont., was substituted therefore, it also was found advisable to include the installation of power at the Hells Canyon reregulation dam instead of adding the installation later. The Phase C system thus modified is termed the Phase C-2 system which is the system recommended to meet the near future needs of the region.

Comparison Phase C and C-2 Power Systems

Project	Installed capacity - kw. Phase C System	Phase C-2 System
Libby	---	588,000
Paradise	576,000	---
Hells Canyon reregulating dam	---	130,000
All other projects (including Willamette and upper Snake River plants)	10,994,000	10,994,000
Total	11,570,000	11,712,000

Phase C-2 system capability. Phase C-2 system operation is little different from the Phase C system because the same low-water period, i.e., September 1929 to February 1932, determines the prime capability of 7,615,000 kilowatts (table 26 on page 0-230). Adding the price capability of the Willamette Valley plants (136,000 kilowatts) and upper Snake River plants (83,000 kilowatts) gives a total system prime capability of 7,834,000 kilowatts for Phase C-2 system.

Appendix O Table 21

Basic Data
Phase C, and Phase C-2 Major Projects

Name of project	Pool elevation Normal	Storage, 1000 acre-feet Usable	Head, feet Average	Number of units installed Phase C-2 Major No.	Installed capacity (name plate rating.) Phase C-2 Major, 1,000 kw.
Libby	2,440	4,250	300	6	588
Hungry Horse	3,559	2,980	409	4	300
Glacier View	3,725	3,160	345	3	210
Paradise*	2,700	4,080	205	8	576
Albeni Falls	2,062.5	1,140	22	3	42.6
Grand Coulee	1,288	5,118	310	18	1,944
Chief Joseph	940	pondage	168	20	1,280
Priest Rapids	550	pondage	146	23	1,219
Kooskia*	1,600	3,100	440	4	440
Hells Canyon	2,075	3,280	493	10	850
Reregulating dam	1,505	20	95	2	130
Lower Snake:					
Lower Granite	715	pondage	81	4	220
Little Goose	633	pondage	99	4	260
Lower Monumental	533	pondage	92	4	240
Ice Harbor	440	pondage	98	4	260
McNary	340	pondage	83	13	910
John Day	255	pondage	94	13	1,105
The Dalles	160	pondage	85	14	980
Bonneville	72	pondage	60	10	518.4

*Alternate projects in main control plan.

Projects Included in the C-2 Phase of Columbia River Development

Existing

Grand Coulee

Bonneville

Under Construction

Hungry Horse (Flathead River)

Chief Joseph

McNary

Albeni Falls (Pend Oreille River)

The Dalles

Under Construction but not in C-2 Phase

Palisades (Snake River)

Authorized

Lower Granite (Snake River)

Little Goose (Snake River)

Lower Monumental (Snake River)

Ice Harbor (Snake River)

Libby (Kootenai River)

Proposed

Glacier View

Priest Rapids

John Day

Hells Canyon Main Dam (Snake River)
Reregulating Dam

UNITED STATES
DEPARTMENT OF THE INTERIOR
Bonneville Power Administration
Portland, 8, Oregon

C O P Y

Prof. Jerome H. Johnson
Department of Electrical Engineering
The State College of Washington
Pullman, Washington

Dear Professor Johnson:

In response to your request of July 17, you will find attached typical weekly load curves for the Western Group Pool Utilities for the months of March, June, September, and December. The Western Group of the Northwest Power Pool consists of the Bonneville Power Administration, the City of Seattle, the City of Tacoma, Puget Sound Power & Light Company, Washington Water Power Company, Pacific Power & Light Company, and the Portland General Electric Company. The actual loads for each of these utilities during typical weeks in March, June, September and December of 1950 are presented in the attached tabulations.

You will also find attached a statement of interruptible load served by the Bonneville Power Administration during each of the months of 1950 and 1951. . . . .

Sincerely yours,

TOTAL LOAD OF WESTERN GROUP OF NORTHWEST POWER POOL
AND BPA INTERRUPTIBLE LOAD, PEAK AND AVERAGE
January 1950 - December 1951
(Thousands of Kilowatts)

	West Group of Northwest Power Pool Excluding B.C.Electric		BPA Interruptible	
	Coincidental Peak Load Total System	Average Load Total System	Average Interruptible Load	Peak Interruptible Load
1950				
January	3,594	2,715	87	90
February	3,538	2,552	89	98
March	3,272	2,533	109	112
April	3,209	2,353	113	116
May	3,190	2,269	119	125
June	3,049	2,218	124	128
July	3,059	2,229	131	136
August	3,118	2,297	136	143
September	3,328	2,388	148	159
October	3,570	2,505	156	159
November	3,815	2,615	164	168
December	3,846	2,645	165	168
1951				
January	3,885	2,767	169	175
February	3,987	2,677	208	218
March	3,769	2,700	214	220
April	3,543	2,534	220	226
May	3,581	2,477	225	231
June	3,511	2,467	237	243
July	3,445	2,442	234	242
August	3,620	2,554	232	241
September	3,619	2,538	205	245
October	3,953	2,675	216	251
November	4,093	2,791	257	260
December	4,157	2,842	243	257

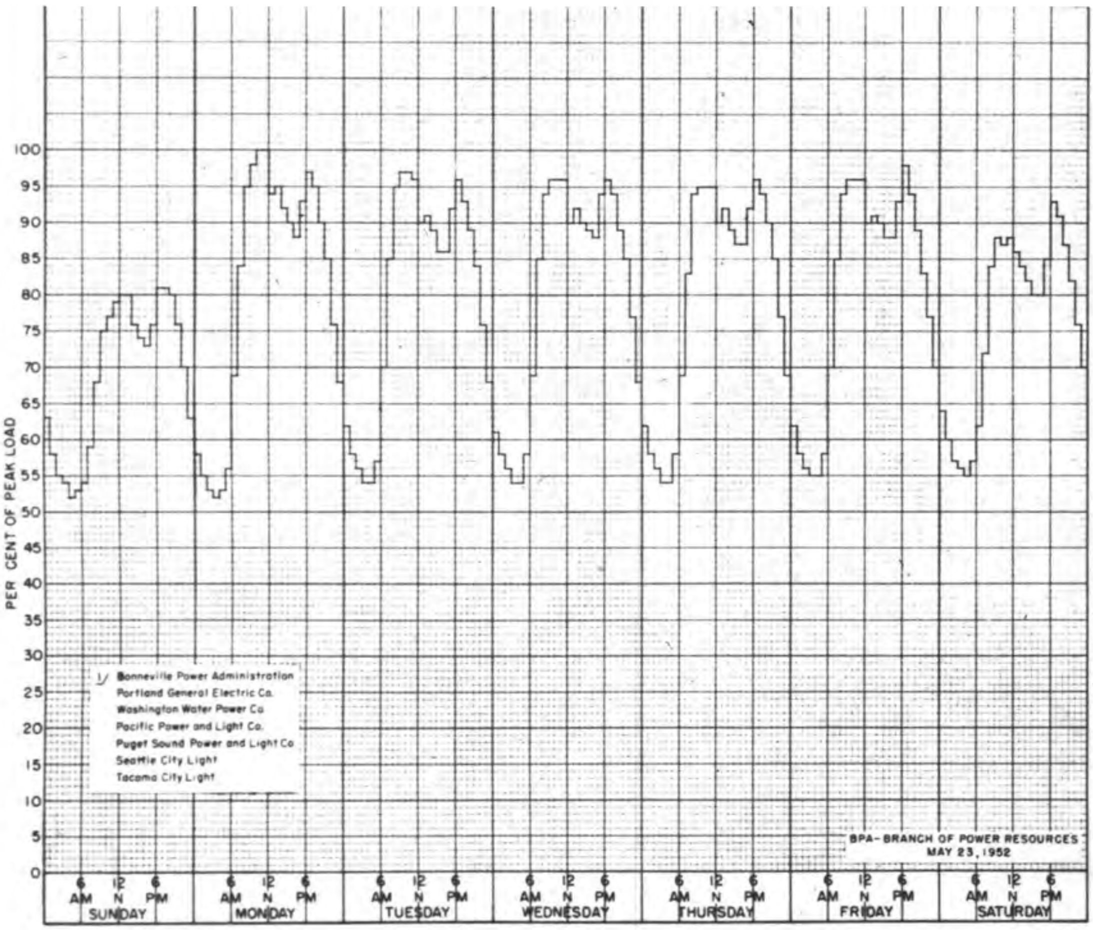
Load Estimating Section
August 11, 1952

TYPICAL WEEKLY LOAD CURVE IN PER CENT OF MAXIMUM DEMAND

MARCH

WESTERN GROUP POOL UTILITIES 1/ OF THE NORTHWEST POWER POOL

BASED ON ACTUAL LOADS FOR 1950



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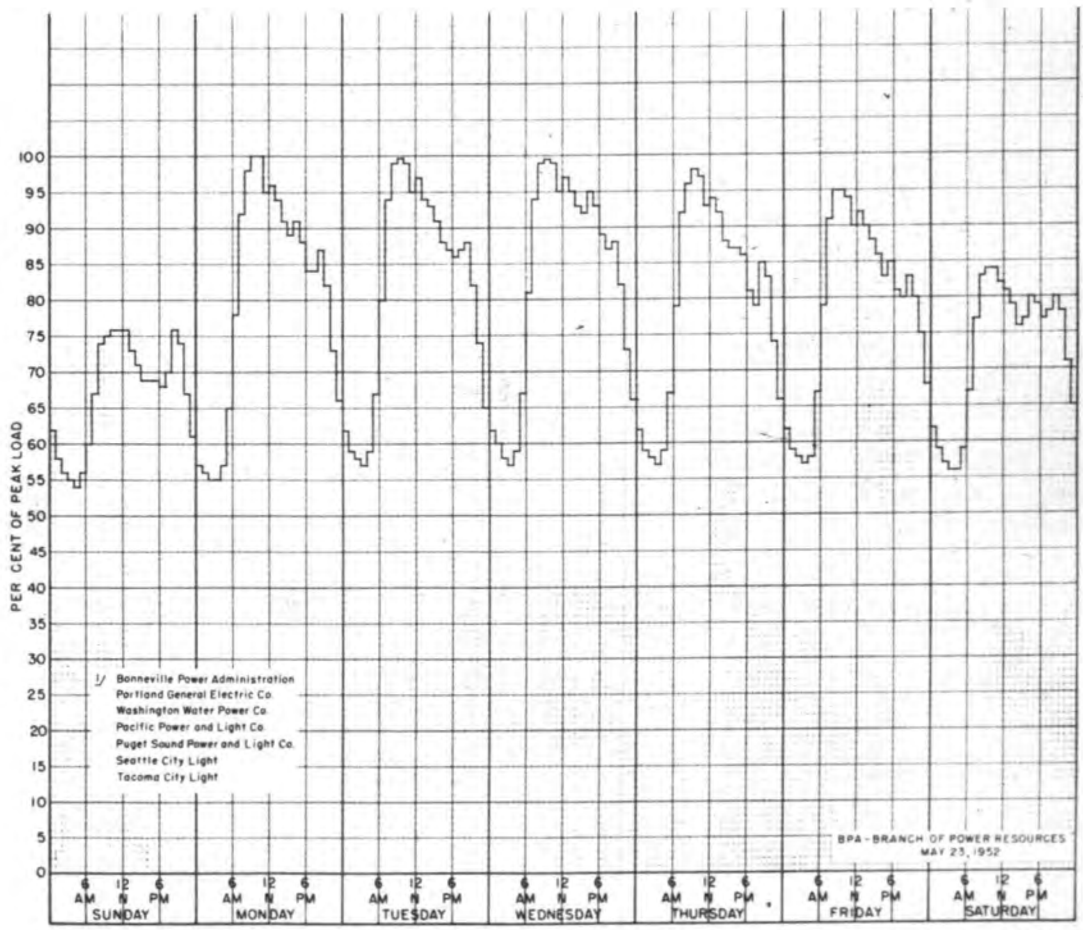
TYPICAL WEEKLY LOAD CURVE IN PER CENT OF MAXIMUM DEMAND

JUNE

WESTERN GROUP POOL UTILITIES 1/ OF THE NORTHWEST POWER POOL

BASED ON ACTUAL LOADS FOR 1950



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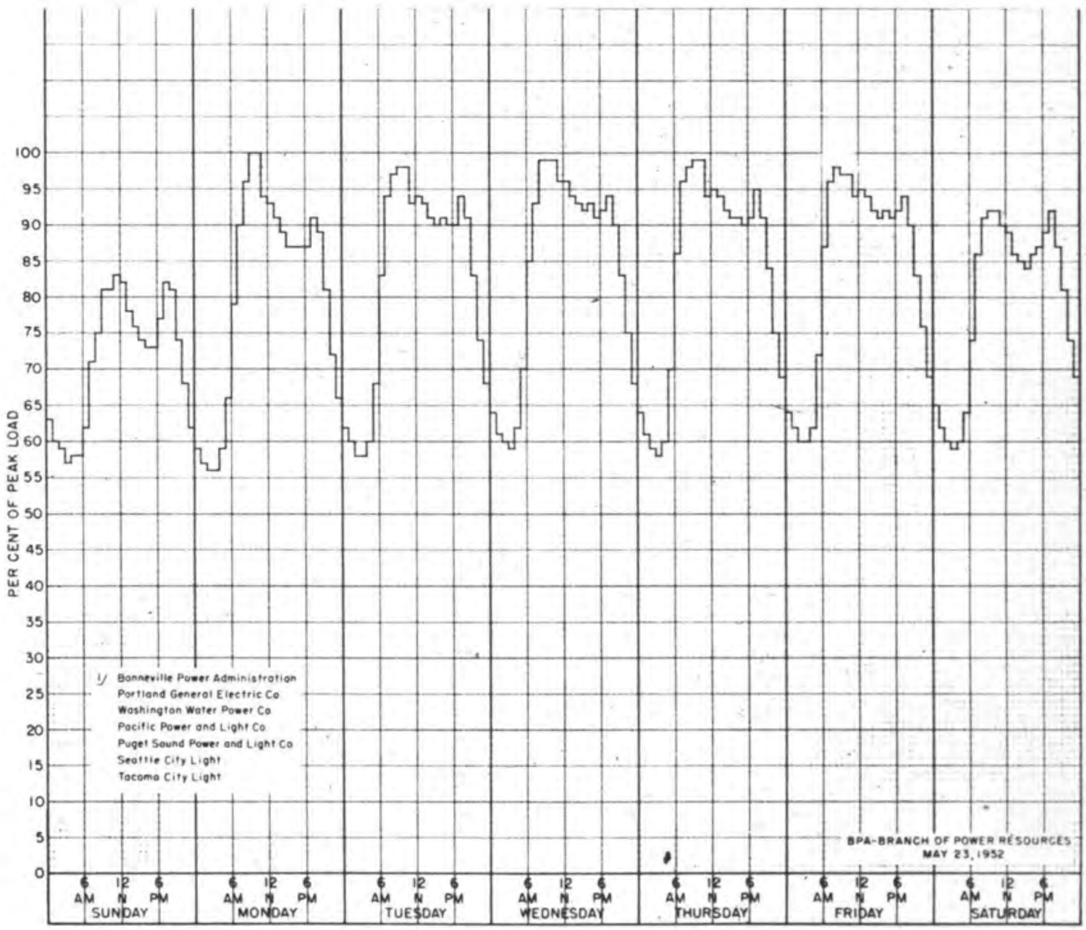
TYPICAL WEEKLY LOAD CURVE IN PER CENT OF MAXIMUM DEMAND

SEPTEMBER

WESTERN GROUP POOL UTILITIES 1/ OF THE NORTHWEST POWER POOL

BASED ON ACTUAL LOADS FOR 1950



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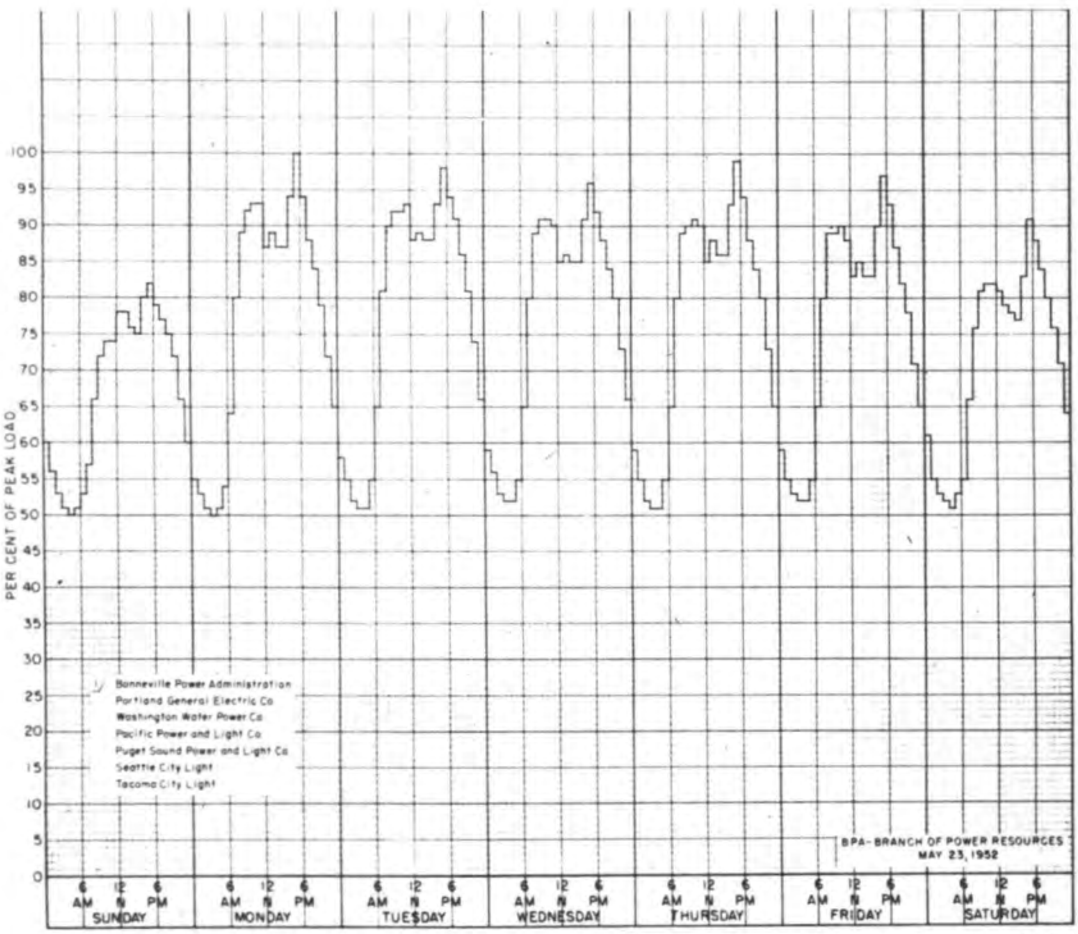
TYPICAL WEEKLY LOAD CURVE IN PER CENT OF MAXIMUM DEMAND

DECEMBER

WESTERN GROUP POOL UTILITIES [1] OF THE NORTHWEST POWER POOL

BASED ON ACTUAL LOADS FOR 1950



60777

Actual Hourly Loads
Western Group Pool Utilities
Thousands of Kilowatts

	KWx1000	% of Total Peak Load
Sunday, March 5, 1950		
12-1 am	2026	63
1-2	1887	58
2-3	1776	55
3-4	1728	54
4-5	1685	52
5-6	1705	53
6-7	1750	54
7-8	1910	59
8-9	2203	68
9-10	2411	75
10-11	2473	77
11-12 noon	2533	79
12-1 pm	2572	80
1-2	2567	80
2-3	2466	76
3-4	2396	74
4-5	2360	73
5-6	2450	76
6-7	2610	81
7-8	2622	81
8-9	2571	80
9-10	2452	76
10-11	2248	70
11-12	2019	63
Monday, March 6, 1950		
12-1 am	1862	58
1-2	1775	55
2-3	1721	53
3-4	1663	52
4-5	1694	53
5-6	1814	56
6-7	2210	69
7-8	2696	84
8-9	3076	95
9-10	3168	98
10-11	3215	100
11-12 noon	3226	100
12-1 pm	3031	94
1-2	3078	95
2-3	2967	92
3-4	2908	90
4-5	2853	88
5-6	2997	93

	KWx1000	% of Total Peak Load
6-7	3144	97
7-8	3051	95
8-9	2906	90
9-10	2729	85
10-11	2437	76
11-12	2180	68
Tuesday, March 7, 1950		
12-1 am	1991	62
1-2	1881	58
2-3	1805	56
3-4	1757	54
4-5	1750	54
5-6	1852	57
6-7	2258	70
7-8	2737	85
8-9	3054	95
9-10	3115	97
10-11	3129	97
11-12 noon	3097	96
12-1 pm	2901	90
1-2	2944	91
2-3	2858	89
3-4	2777	86
4-5	2767	86
5-6	2984	92
6-7	3106	96
7-8	3015	93
8-9	2873	89
9-10	2710	84
10-11	2467	76
11-12	2194	68
Wednesday, March 8, 1950		
12-1 am	1973	61
1-2	1873	58
2-3	1798	56
3-4	1749	54
4-5	1754	54
5-6	1864	58
6-7	2214	69
7-8	2730	85
8-9	3047	94
9-10	3093	96
10-11	3107	96
11-12 noon	3094	96
12-1	2914	90
1-2	2967	92
2-3	2899	90
3-4	2860	89
4-5	2845	88
5-6	3029	94

	KWx1000	% of Total Peak Load
6-7	3101	96
7-8	3040	94
8-9	2887	89
9-10	2743	85
10-11	2484	77
11-12	2209	68
Thursday, March 9, 1950		
12-1 am	2010	62
1-2	1877	58
2-3	1822	56
3-4	1758	54
4-5	1757	54
5-6	1876	58
6-7	2238	69
7-8	2681	83
8-9	3018	94
9-10	3070	95
10-11	3078	95
11-12 noon	3066	95
12-1	2912	90
1-2	2968	92
2-3	2856	89
3-4	2817	87
4-5	2820	87
5-6	2963	92
6-7	3089	96
7-8	3033	94
8-9	2913	90
9-10	2744	85
10-11	2484	77
11-12	2215	69
Friday March 10, 1950		
12-1 am	1947	62
1-2	1882	58
2-3	1813	56
3-4	1764	55
4-5	1769	55
5-6	1879	58
6-7	2249	70
7-8	2731	85
8-9	3045	94
9-10	3105	96
10-11	3098	96
11-12 noon	3099	96
12-1 pm	2916	90
1-2	2950	91
2-3	2898	90
3-4	2847	88
4-5	2833	88
5-6	2995	99

	KWx1000	% of Total Peak Load
6-7	3147	98
7-8	3048	94
8-9	2881	89
9-10	2690	83
10-11	2488	77
11-12	2247	70
Saturday, March 11, 1950		
12-1 am	2063	64
1-2	1926	60
2-3	1853	57
3-4	1796	56
4-5	1781	55
5-6	1841	57
6-7	2002	62
7-8	2338	72
8-9	2700	84
9-10	2823	88
10-11	2813	87
11-12 noon	2830	88
12-1 pm	2784	86
1-2	2716	84
2-3	2634	82
3-4	2573	80
4-5	2590	80
5-6	2754	85
6-7	2993	93
7-8	2948	91
8-9	2814	87
9-10	2654	82
10-11	2452	76
11-12	2244	70
	423479 Total	

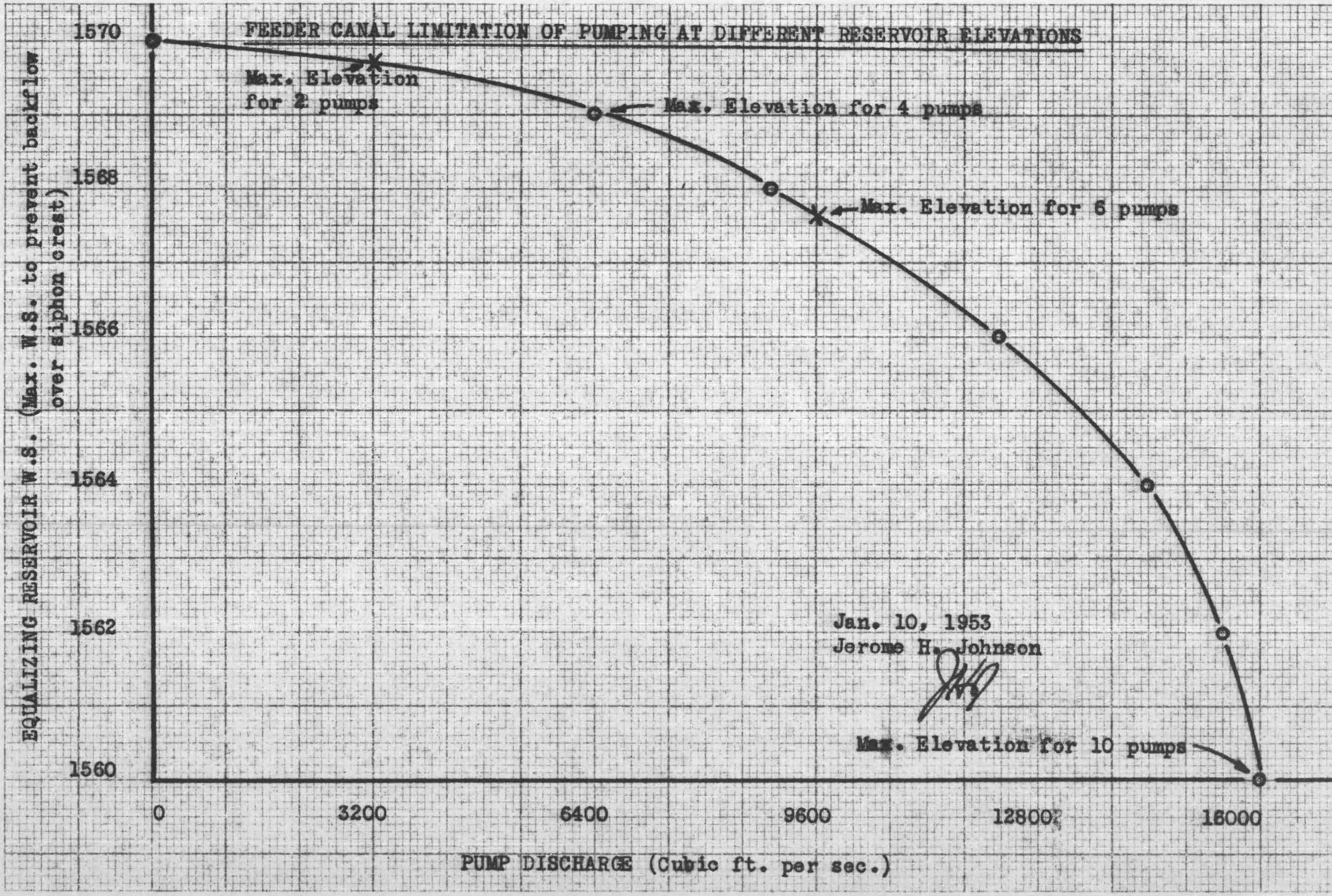
Similar data for typical weeks in the months of June, September, and December of 1950 are also available, but will not all be reproduced here because of their volume. The results of the data are shown plotted in the included Load Curves. Data necessary for the calculation of the Load Factors for these weeks are given below.

	Total mw-hr for period	Maximum mw for period
June 4-10, 1950	393,724 mw-hr	3025 mw
Sept. 10-16, 1950	422,456 mw-hr	3119 mw
December 3-9, 1950	474,402 mw-hr	3771 mw

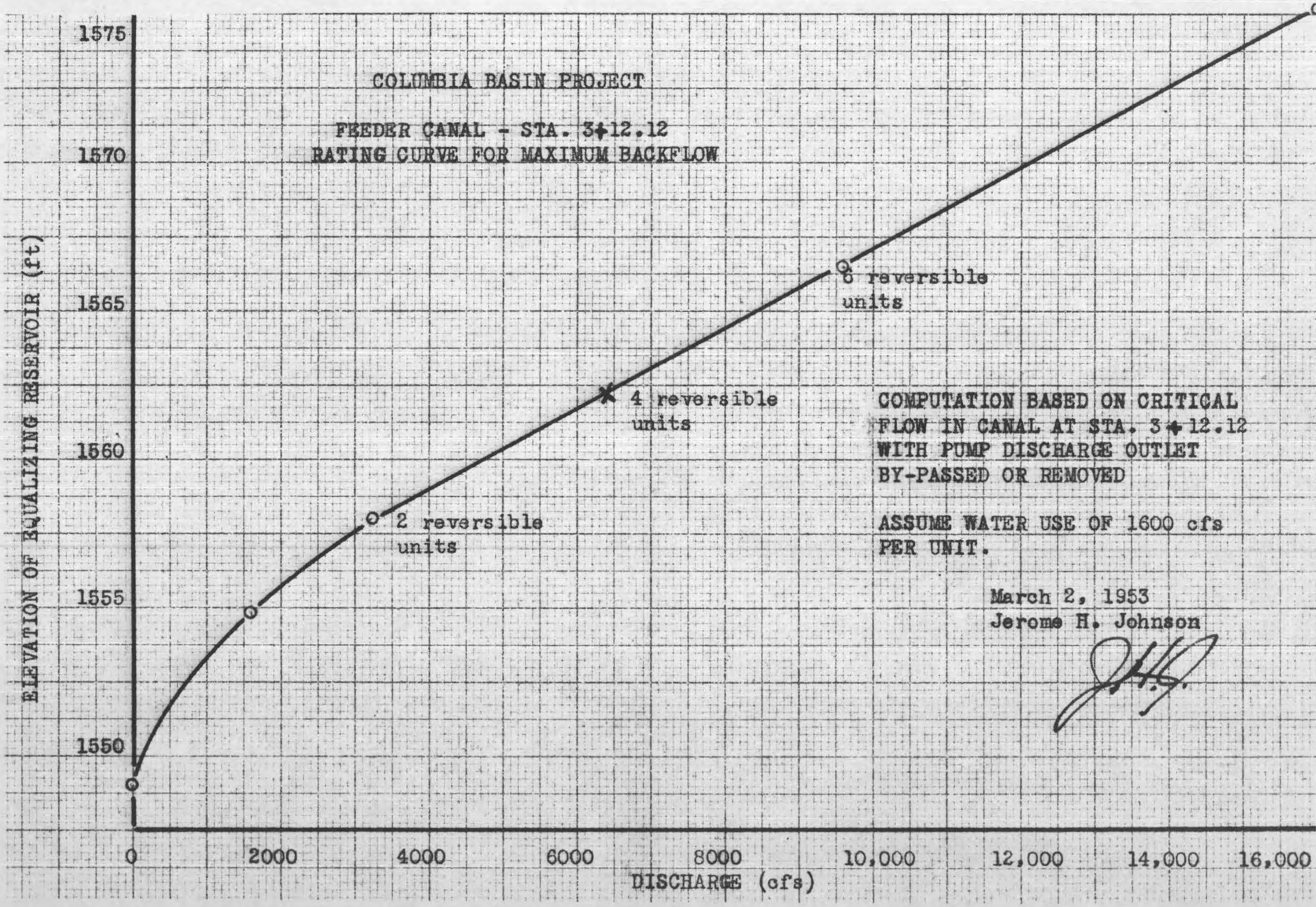
<u>Feeder Canal Flow Characteristics Curves</u>. The Feeder Canal limits the flow of water in both directions. The canal was originally designed for flow only from the penstock outlets to the Equalizing Reservoir. However, the drop in elevation over its length is rather small, so that it would be possible to have flow in the reverse direction when the Equalizing Reservoir elevation is great enough.

For flow towards the Equalizing Reservoir during the pumping process, the limiting factor is the pump discharge allowable without causing backflow over the siphon crest at different reservoir elevations. This curve data was obtained from interpreting another curve included on the print in the following section showing the profile of the Feeder Canal and Setions.

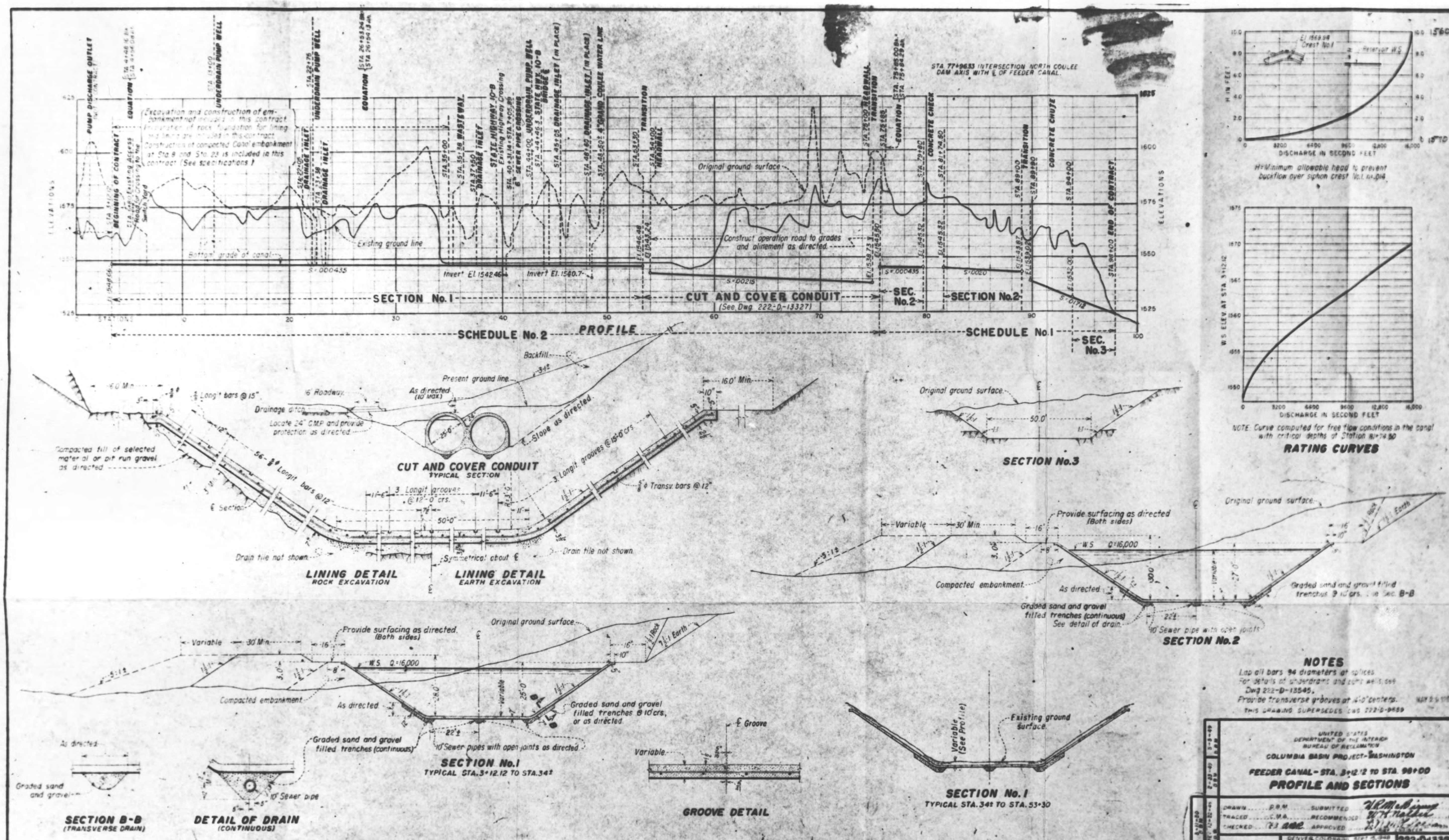
The data for the Feeder Canal Rating Curve for Maximum Backflow is calculated, as shown in the section under Calculations. The limitation here is much more severe. That the limitation should be more rigid is logical, as water flows less readily up hill, even though the slope is gentle.



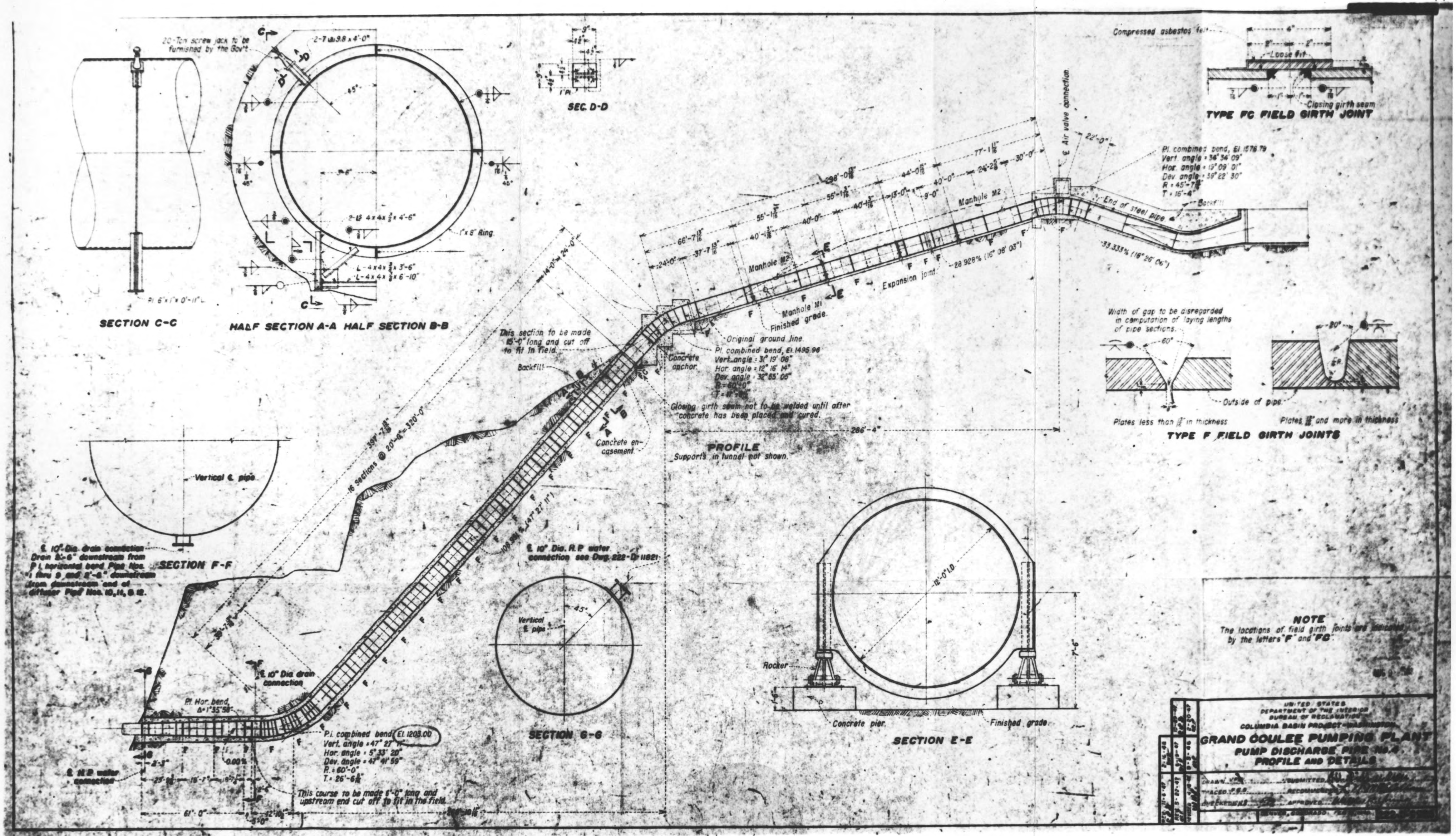
FEEDER CANAL LIMITATION OF PUMPING AT DIFFERENT RESERVOIR ELEVATIONS
EQUALIZING RESERVOIR W.S. (Max. W.S. to prevent backflow over siphon crest)
1570
1568
1566
1564
1562
1560
Max. Elevation for 2 pumps
Max. Elevation for 4 pumps
Max. Elevation for 6 pumps
Max. Elevation for 10 pumps
Jan. 10, 1953
Jerome H. Johnson
0
3200
6400
9600
12800
16000
PUMP DISCHARGE (Cubic ft. per sec.)


COLUMBIA BASIN PROJECT
FEEDER CANAL - STA. 3+12.12
RATING CURVE FOR MAXIMUM BACKFLOW
ELEVATION OF EQUALIZING RESERVOIR (ft)
1575
1570
1565
1560
1555
1550
6 reversible units
4 reversible units
2 reversible units
COMPUTATION BASED ON CRITICAL FLOW IN CANAL AT STA. 3+12.12 WITH PUMP DISCHARGE OUTLET BY-PASSED OR REMOVED
ASSUME WATER USE OF 1600 cfs PER UNIT.
March 2, 1953
Jerome H. Johnson
0
2000
4000
6000
8000
10,000
12,000
14,000
16,000
DISCHARGE (cfs)

<u>Prints of the Feeder Canal and Canal Sections, and of the Penstocks.</u>



PROFILE
SCHEDULE No. 2
SCHEDULE No. 1
SECTION No. 1
CUT AND COVER CONDUIT
(See Dwg. 222-D-13327)
SEC. No. 2
SECTION No. 2
SEC. No. 3
ELEVATIONS
STATIONS
PUMP DISCHARGE OUTLET
BEGINNING OF CONTRACT
EQUATION
UNDERDRAIN PUMP WELL
DRAINAGE INLET
WASTEWAY
STATE HIGHWAY 10-B
Existing Highway Crossing
TRANSITION
HEADWALL
CONCRETE CHECK
CONCRETE CHUTE
END OF CONTRACT
Original ground surface
Existing ground line
Bottom grade of canal
Construct operation road to grades and alinement as directed.
Invert El. 1542.46
Invert El. 1540.7
S=.000435
S=.00215
S=.0020
S=.01712
STA. 77+96.53 INTERSECTION NORTH COULEE DAM AXIS WITH ℄ OF FEEDER CANAL.
Excavation and construction of embankment not included in this contract. Preparation of rock foundation for lining and lining are included in this contract. Construction of compacted Canal embankment at Sta. 8 and Sta. 23 is included in this contract. (See specifications.)
CUT AND COVER CONDUIT
TYPICAL SECTION
Present ground line
Backfill
As directed (10' max.)
16' Roadway
Drainage ditch
Locate 24" C.M.P. and provide protection as directed
Slope as directed
Compacted fill of selected material or pit run gravel as directed
3 Longit. grooves @ 12'-0" crs.
3 Longit. grooves @ 15'-0" crs.
Transv. bars @ 12"
Longit. bars @ 15"
Longit. bars @ 12"
℄ Section
Drain tile not shown.
Symmetrical about ℄
LINING DETAIL
ROCK EXCAVATION
LINING DETAIL
EARTH EXCAVATION
SECTION No. 3
SECTION No. 2
Provide surfacing as directed (Both sides)
Variable
30' Min.
W.S. Q=16,000
Compacted embankment
As directed
Graded sand and gravel filled trenches (continuous). See detail of drain.
10" Sewer pipe with open joints
Graded sand and gravel filled trenches @ 10' crs. See Sec. B-B
Earth
Rock
SECTION No. 1
TYPICAL STA. 3+12.12 TO STA. 34±
Graded sand and gravel filled trenches @ 10' crs., or as directed.
Graded sand and gravel filled trenches (continuous)
10" Sewer pipes with open joints as directed
SECTION B-B
(TRANSVERSE DRAIN)
Graded sand and gravel
DETAIL OF DRAIN
(CONTINUOUS)
10" Sewer pipe
GROOVE DETAIL
℄ Groove
SECTION No. 1
TYPICAL STA. 34± TO STA. 53+30
Existing ground surface
Variable (See Profile)
RATING CURVES
DISCHARGE IN SECOND FEET
H IN FEET
W.S. ELEV. AT STA. 3+12.12
H=Minimum allowable head to prevent backflow over siphon crest
NOTE: Curve computed for free flow conditions in the canal with critical depths at Station 81+74.80
NOTES
Lap all bars 34 diameters at splices.
For details of underdrains and pump wells see Dwg. 222-D-13545.
Provide transverse grooves at 15'-0" centers.
THIS DRAWING SUPERSEDES DWG. 222-D-9689
UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF RECLAMATION
COLUMBIA BASIN PROJECT—WASHINGTON
FEEDER CANAL—STA. 3+12.12 TO STA. 98+00
PROFILE AND SECTIONS
DRAWN
TRACED
CHECKED
SUBMITTED
RECOMMENDED
APPROVED
DENVER, COLORADO
222-D-13324


SECTION C-C
20-Ton screw jack to be furnished by the Gov't.
HALF SECTION A-A HALF SECTION B-B
1"x 8" Ring.
SEC. D-D
TYPE FC FIELD GIRTH JOINT
Compressed asbestos felt
Loose fit
Closing girth seam
Air valve connection
Pl. combined bend, El. 1576.79
End of steel pipe
Backfill
Manhole M2
Manhole M1
Expansion joint
Finished grade.
Original ground line.
Pl. combined bend, El. 1495.96
Concrete anchor.
This section to be made 15'-0" long and cut off to fit in field.
Closing girth seam not to be welded until after concrete has been placed and cured.
Concrete encasement.
PROFILE
Supports in tunnel not shown.
16 Sections @ 20'-0" = 320'-0"
Width of gap to be disregarded in computation of laying lengths of pipe sections.
Outside of pipe.
Plates less than 5/8" in thickness
Plates 5/8" and more in thickness
TYPE F FIELD GIRTH JOINTS
Vertical ℄ pipe
SECTION F-F
℄ 10" Dia. drain connection
℄ 10" Dia. R.P. water connection see Dwg. 222-D-11821
SECTION G-G
Rocker
Concrete pier.
Finished grade.
SECTION E-E
NOTE
The locations of field girth joints are indicated by the letters "F" and "FC".
Pl. combined bend El. 1203.00
This course to be made 6'-0" long and upstream end cut off to fit in the field.
UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF RECLAMATION
COLUMBIA BASIN PROJECT-WASHINGTON
GRAND COULEE PUMPING PLANT
PUMP DISCHARGE PIPE NO. 4
PROFILE AND DETAILS

Projected Irrigation Water Requirements. Data and Curves.

COLUMBIA BASIN PROJECT
SUMMARY OF PRIMARY PUMPING REQUIREMENTS
(In 1000's of Acre-Feet)

Estimated Monthly Diversions from Equalizing Reservoir[1]

Month	1952	1953	1954	1955	1956	1957
March	32.0	37.6	42.6	44.9	51.0	65.3
April	69.0	98.0	126.0	150.0	200.0	230.0
May	70.0	102.0	146.0	185.0	220.0	270.0
June	80.0	102.0	156.0	205.0	220.0	270.0
July	80.0	90.0	140.0	180.0	220.0	270.0
August	70.0	80.0	130.0	160.0	200.0	230.0
September	50.0	80.0	110.0	140.0	175.0	180.0
October	40.0	64.0	75.0	75.0	90.0	80.0
	491.0	653.6	925.6	1,139.9	1,376.0	1,595.3
Additional for dilution[2] of pumpage from Lake Lenore	18.0	36.0	36.0	36.0	18.0	-
Total Annual Diversions	509.0	689.6	961.6	1,175.9	1,394.0	1,595.3
Estimated Requirements for Equalizing Reservoir						
(a) Estimated losses	84.4	87.4	90.4	93.4	96.4	99.4
(b) Addition to Storage[3]	56.2	100.0	108.0	115.0	121.0	127.0
TOTAL ANNUAL REQUIREMENTS	649.6	877.0	1,160.0	1,384.3	1,611.4	1,821.7

[1]Based on estimates of (a) rate of construction, (b) occupancy and development of the farms, (c) canal and lateral losses and operating wastes, and (d) recovery and re-use of return flow in Potholes Reservoir.

[2]Estimated rate of 150 c.f.s. during non-irrigation seasons for years shown.

[3]Assumed reservoir level at 1540 at end of 1952 irrigation season; thereafter, level increased 5 feet annually until 1570 is reached.

COLUMBIA BASIN PROJECT
SUMMARY OF PRIMARY PUMPING REQUIREMENTS
(In 1000's of Acre-Feet)
(Continued)

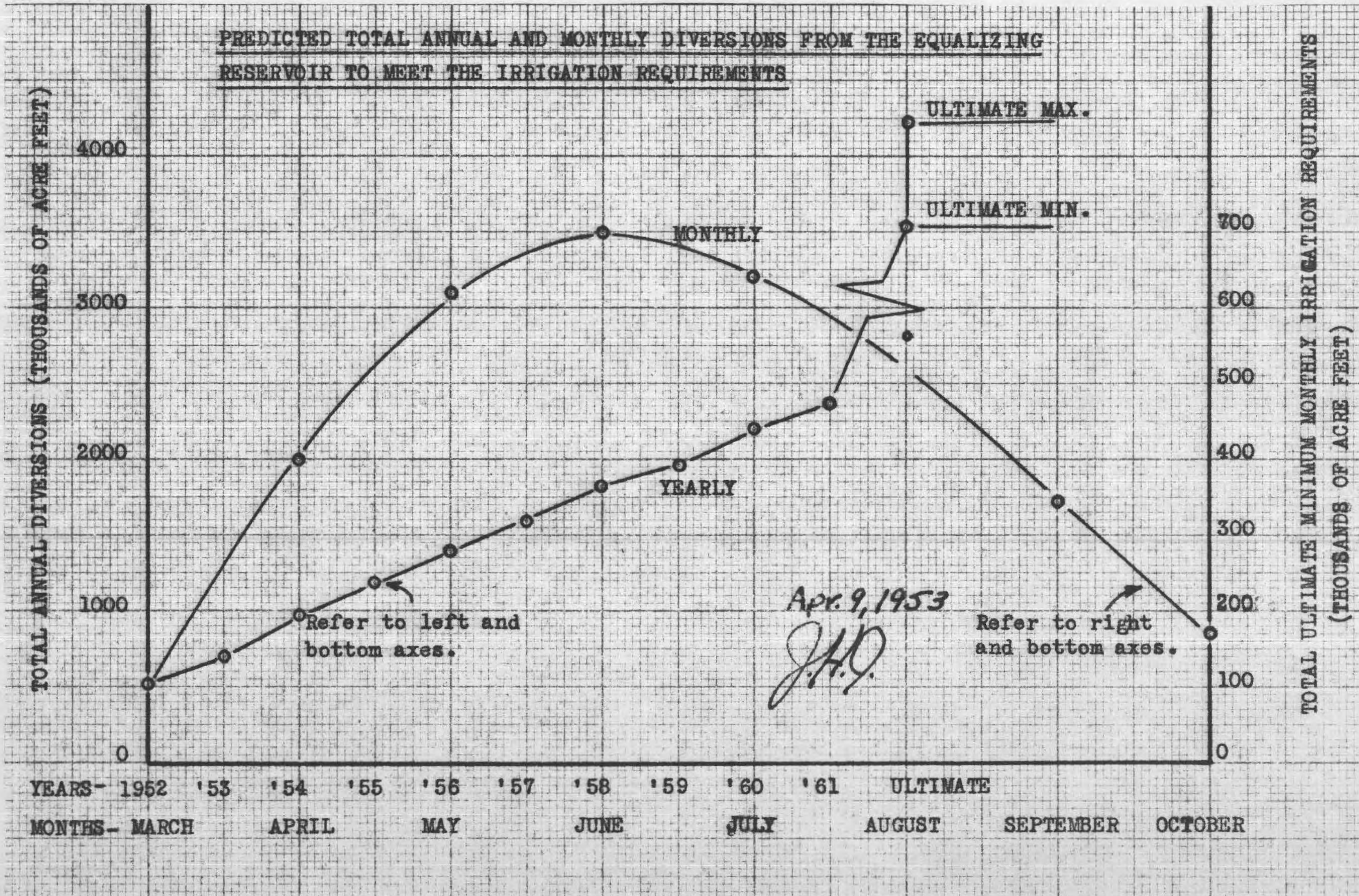
Estimated Monthly Diversions from Equalizing Reservoir[1]

Month	1958	1959	1960	1961	"Min." Ultimate	"Max." Ultimate
March	76.0	89.7	90.3	99.5	100.0	124.4
April	260.0	280.0	320.0	360.0	400.0	570.0
May	300.0	320.0	360.0	380.0	620.0	720.0
June	300.0	320.0	360.0	380.0	700.0	787.0
July	300.0	320.0	360.0	380.0	640.0	720.0
August	270.0	300.0	330.0	370.0	565.0	700.0
September	200.0	225.0	250.0	260.0	340.0	400.0
October	110.0	140.0	130.0	140.0	170.0	200.0
	1,816.0	1,994.7	2,200.3	2,369.5	3,535.1	4,221.4
Additional for dilution[2] of pumpage from Lake Lenore	-	-	-	-	-	-
Total Annual Diversions	1,816.0	1,994.7	2,200.3	2,369.5	3,535.1	4,221.4
Estimated Requirements for Equalizing Reservoir						
(a) Estimated losses	99.4	99.4	99.4	99.4	99.4	99.4
(b) Addition to Storage[3]	133.0	0	0	0	0	0
TOTAL ANNUAL REQUIREMENTS	2,048.4	2,094.1	2,299.7	2,468.9	3,634.5	4,320.8

[1]Based on estimates of (a) rate of construction, (b) occupancy and development of the farms, (c) canal and lateral losses and operating wastes, and (d) recovery and re-use of return flow in Potholes Reservoir.

[2]Estimated rate of 150 c.f.s. during non-irrigation seasons for years shown.

[3]Assumed reservoir level at 1540 at end of 1952 irrigation season; thereafter, level increased 5 feet annually until 1570 is reached.


PREDICTED TOTAL ANNUAL AND MONTHLY DIVERSIONS FROM THE EQUALIZING
RESERVOIR TO MEET THE IRRIGATION REQUIREMENTS
TOTAL ANNUAL DIVERSIONS (THOUSANDS OF ACRE FEET)
TOTAL ULTIMATE MINIMUM MONTHLY IRRIGATION REQUIREMENTS
(THOUSANDS OF ACRE FEET)
0
1000
2000
3000
4000
100
200
300
400
500
600
700
ULTIMATE MAX.
ULTIMATE MIN.
MONTHLY
YEARLY
Refer to left and
bottom axes.
Refer to right
and bottom axes.
Apr. 9, 1953
J.H.D.
YEARS- 1952 '53 '54 '55 '56 '57 '58 '59 '60 '61 ULTIMATE
MONTHS- MARCH APRIL MAY JUNE JULY AUGUST SEPTEMBER OCTOBER

Primary Pumping Requirements in Kw-hr and Acre-ft.

UNITED STATES
DEPARTMENT OF THE INTERIOR
Bureau of Reclamation
Columbia River District-Columbia Basin Project
Ephrata, Washington

C O P Y

To: Regional Director, Boise, Idaho

From: District Manager, Ephrata

Subject: Primary pumping requirements--Grand Coulee Pumping Plant--Columbia Basin Project.

. . . . .

PRIMARY PUMPING POWER DEMAND - 1000 KWH

Calendar Year	April	May	June	July	Aug.	Sept.
1952		17,100	66,800	104,500		
1953		63,000	112,800	112,800		
1954		110,000	132,300	132,300		
1955		122,000	174,000	174,000		
1956		180,000	174,000	180,000	6,100	
1957		180,000	174,000	180,000	138,200	
1958		180,000	174,000	180,000	180,000	
1959	4,500	180,000	174,000	180,000	180,000	
1960	87,700	180,000	174,000	180,000	180,000	
Ultimate*	129,400	318,000	307,000	318,000	318,000	174,000

*This represents the "Max." ultimate figure shown on Chart 271.

This tabulation was computed from Irrigation O & W Division Chart No. 271, revised March 20, 1952, a copy of which is enclosed, and Equalizing Reservoir Losses used were those shown on that chart. Full consideration has been given to Bonneville Power Administration's priority of months most favorable for pumping. May, June and July are considered most favorable; the full month of August having second priority; the period from April 30 back to April 15 third priority; and the month of September considered least favorable. The tabulation has held strictly to these priorities. From 1956 through 1960, six pumps are shown as operating continuously through May, June and July except for 96 hours per month for the six pumps which time is left available for unscheduled outages and for power production during peak demands. In the ultimate year, there is scheduled continuous pumping from April 15 through August except for 72 hours per month for ten pumps which time is left available for unscheduled outages and power production during the peak demands. . . . .

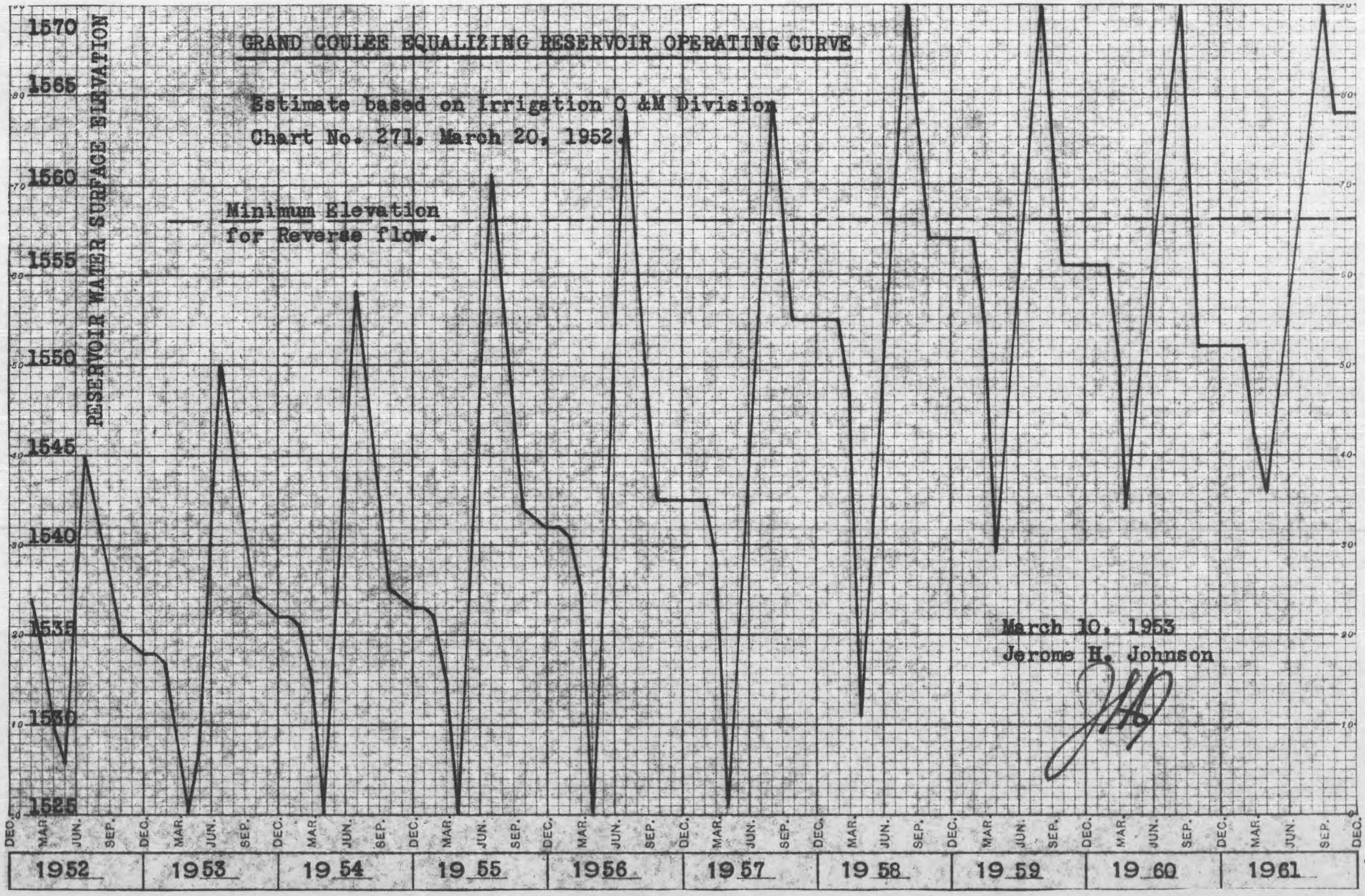
PRIMARY PUMPING REQUIREMENTS - ACRE FEET

Calendar Year	April	May	June	July	Aug.	Sept.
1952	--	48,000	192,000	300,000	--	--
1953	--	172,000	324,000	324,000	--	--
1954	--	300,000	380,000	380,000	--	--
1955	--	333,100	500,000	500,000	--	--
1956	--	492,000	500,000	518,000	17,400	--
1957	--	492,000	500,000	518,000	396,900	--
1958	--	492,000	500,000	518,000	518,000	--
1959	11,100	492,000	500,000	518,000	518,000	--
1960	187,000	492,000	500,000	518,000	518,000	--
1961*	312,000	492,000	500,000	518,000	518,000	451,700
*Minimum Ultimate	312,000	863,000	864,000	896,000	645,300	54,200
Maximum Ultimate	312,000	863,000	864,000	896,000	896,000	489,800

<u>Note</u>: Above tabulation corresponds to KWH demand as shown in District Manager's letter of March 28, 1952.

*Primary Pumping Power Demand - 1,000 KWH (Years not shown in District Manager's letter).

1961	126,700	180,100	174,000	180,200	180,200	157,200
Minimum Ultimate	129,400	318,000	307,000	318,000	229,000	19,200


GRAND COULEE EQUALIZING RESERVOIR OPERATING CURVE
Estimate based on Irrigation O &M Division
Chart No. 271, March 20, 1952.
Minimum Elevation
for Reverse flow.
RESERVOIR WATER SURFACE ELEVATION
1570
1565
1560
1555
1550
1545
1540
1535
1530
1525
DEC. MAR. JUN. SEP.
1952
1953
1954
1955
1956
1957
1958
1959
1960
1961
March 10, 1953
Jerome H. Johnson
JHJ

Data on Pumps and Motors Presently Installed in the Grand Coulee Pumping Plant.

Pumps:

Single stage, vertical shaft, centrifugal type.

Designed by Byron-Jackson Company of Los Angeles.

Constructed by the Pelton Water Wheel Company of San Francisco.

Rated at 1350 cfs at a head of 310 ft, or at 1600 cfs at a head of 280 ft.

Speed: 200 rpm.

Impeller diameter is 13 ft, 11 3/8 in.

Pumps set on 45 ft. centers. Pump pits approximately 41 ft. square.

Motors:

Rated at 65,000 hp at unity power factor, 3 phase, 60 cycle, 13,600 volts, 200 rpm.

The motor rotors are equipped with amortisseur windings which permit starting the motors as induction motors, and could act as damping windings for generator action.

The motors have an efficiency of approximately 97%, giving them a kva rating of 50,000 kva.

The bearings of the motors and pumps are constructed for rotation in either direction.

<u>Data Presently Available on the Reverse Flow Characteristics of the Present Pumping Units</u>. There is no actual reverse flow data on the present pump units. The Equalizing Reservoir will not be at the necessary elevation for several years so that this data may be obtained in actual load runs. The pump designers, the Byron Jackson Company of Los Angeles, suggested that Robert T. Knapp, professor of hydraulics at the California Institute of Technology might be able to give the most valuable information on this subject, as he had acted as a consultant in the design of the pumps. Dr. Knapp's letter is included in the Data, as it gives a good estimate of the possible rating, efficiency, and general limitations involved in adapting the pumps to reverse flow operation.

CALIFORNIA INSTITUTE OF TECHNOLOGY
Pasadena

C O P Y

Prof Jerome H. Johnson
Department of Electrical Engineering
Washington State Institute of Technology
State College of Washington
Pullman, Washington

Dear Prof. Johnson:

Your letter of July 7 asking for information regarding the turbine characteristics of the Grand Coulee pumps was received while I was away. Since I returned I have been trying to look into the subject a little bit for you.

In the first place, there is no basic information concerning reverse flow characteristics, i.e., turbine operation. There is some question as to whether the model of the pumps that were installed was ever tested for reverse flow characteristics. In any case, however, there has been enough change made in the runner and case since installation so that for anything except the most approximate information, it would be necessary to make a new test. I think this could easily be done at Byron Jackson if it were requested by the Bureau of Reclamation, and an order given the company.

In general these units will operate very satisfactorily as turbines; however, they have no load control characteristics, i.e., for any given height they will produce only one set amount of power if operated at synchronous speed, i.e., they will be block load units. They should operate very stably under these conditions.

The horsepower rating of such pumps operating as turbines is less than the horsepower requirements for pumps under the same condition. For example, one of the pumps studied previously for the Grand Coulee showed a turbine horsepower output of about 60% of the pump horsepower input for the same head and speed. If the turbine could be operated at slightly different speed than the pump, these results would be modified drastically.

The efficiency of the pump operated as a turbine will be very nearly the same as that of the pump itself; depending upon the operating point, it may be one or two percent higher or one or two percent lower.

It is possible that the cavitation characteristics of the machine may be a limiting factor. This again would depend upon the individual design.

I hope that these comments may be of use to you.

Manufacturer information from the Allis-Chalmers Company and the Baldwin-Lima-Hamilton Corporation on Reversible Pump-Turbine Units. Copies of these letters are inserted, as they include information on the availability, relative cost, expected efficiency, and much other pertinent information on reversible pump-turbine units presently available from two reputable manufacturing concerns.

BALDWIN - LIMA - HAMILTON CORPORATION
Eddystone Division
Philadelphia 42, Pa.

C O P Y

Mr. Jerome H. Johnson
Assistant Professor of Electrical Engineering
The State College of Washington
Pullman, Washington

Dear Mr. Johnson:

. . . . . There are two possible types. The conventional type having adjustable wicket gates would provide control of water flow, like a Francis turbine, and, in appearance, would be similar to a low specific speed Francis turbine. This arrangement would give the best overall efficiency and flexibility. The other type would be very similar to a conventional pump with fixed discharge vanes. This unit could operate on constant load only, there being no means of varying the rate of flow. In this case a Johnson valve could be used to control the rate of flow for synchronizing purposes, or one of the several electrical methods of starting the unit while unwatered might be considered. From the standpoint of existing structure, such a unit as this would involve the fewest design problems resulting from space limitations, and setting with respect to tailwater elevation. With either of the above types of machines it is doubtful that the same speed could be adhered to as used on the present pumps at Grand Coulee. However, this would not seem to be a requisite condition so long as the pump and turbine speeds were the same . . . . .

Because of the restrictions placed upon the design of a pump turbine for this installation by the powerhouse structure already in place, it would be necessary to make model tests of a pump turbine designed specifically for the job. If it is to have wicket gates it must, necessarily, have a higher specific speed as a pump than the present pumps. This would require a lower setting with respect to suction water level, or, alternatively, the lake level would have to be held to a higher elevation than 1208 feet, in order to avoid cavitation. To give you more specific information we should know which of the two types of units you have in mind.

The general statement, however, can be made that there is a good chance that a pump turbine can be installed to meet the general requirements, particularly if speed and suction water level can be changed, or if the setting of the unit could be lowered somewhat.

Maximum turbine efficiency would be about 90%, and pump efficiency about 88%, assuming a step-up in prototype versus model efficiency. The cost of a pump turbine, with wicket gates, would be, very roughly, \$600,000.00. This would be reduced about one-third if wicket gates were not required. In addition to the above expense, the Bureau would, no doubt, want to conduct an experimental program which would probably run between \$50,000.00 and \$100,000.00. If the tests of the manufacturer in his own laboratory, under lower heads, were acceptable, this expense would be cut in half.

Very truly yours,

ALLIS-CHALMERS MANUFACTURING COMPANY
Main Office - Box 512
Milwaukee 1, Wis.

C O P Y

Prof. Jerome H. Johnson
Dept. of Electrical Engineering
The State College of Washington
Pullman, Washington

Dear Sir:

With reference to your letter of July 7, 1951, our comments are as follows:

1. Reversible turbines (pump turbines) can be built for output up to 100,000 hp or even larger for the high heads above 600 feet. They can be built for the requirements at Grand Coulee Dam.

2. They can be supplied for the six (6) future units at Grand Coulee Dam.

3. For heads above about 150 feet there is an advantage of operating at two speeds, a lower speed for generating and slightly higher speed for pumping.
   If the head varies for turbine operation so that the minimum head is about 20 percent lower than the maximum head operation at two speeds will produce higher efficiency and greater horsepower output.

4. When starting the unit for pumping we would use the usual procedure that is used for large pumps.

5. We cannot make a general statement as to the cost of a reversible turbine compared to a Francis turbine, but it would probably be slightly higher. However, this would be justified because we have a dual purpose unit which can be used for pumping or generating power.

Yours very truly,

Steam Plant Capacity Presently Installed in the Pacific Northwest, Including Cost Data. The location, average and peak capability, total costs of operation, and unit cost in mills per kwh is given. It shows very graphically the limitations and handicaps of the present sources of peak power and reserve capacity.

UNITED STATES
DEPARTMENT OF THE INTERIOR
Bonneville Power Administration
Portland 8, Oregon

C O P Y

Mr. Jerome H. Johnson
Assistant Professor of
Electrical Engineering
State College of Washington
Pullman, Washington

Dear Mr. Johnson:

. . . . . Actual operation of these plants depends on available hydro generation and the necessity of using high cost generation to meet load requirements. Under minimum year hydro conditions, which occur on the average of every four years, the entire energy output is needed during a six month period to meet present firm load requirements. This condition is expected to continue for several years in the future. With average water conditions and normal operations, the more economical plants, such as Shuffleton, Station "L", Lincoln and Tacoma #2, will probably be used on a spinning reserve basis about one-half of the time. About 10 to 15 per cent of the energy capability is required to operate for spinning reserve. . . .

Very truly yours,

STEAM PLANT COSTS - CITY OF TACOMA
DEPARTMENT OF PUBLIC UTILITIES, LIGHT DIVISION
Operation and Maintenance
Average Monthly Costs
1951-52

	Hot Standby	Percent of Energy Capability 25	50	75	100
STEAM PLANT #1 - Tacoma, Installed 1922 (9 Mw Peak Capability)					
Average Generation Mw	.5	2.0	4.0	6.0	8.0
Operating Labor	$ 2,800	$ 4,000	$ 4,400	$ 5,000	$ 6,000
Fuel Cost @ $2.12/BBL.	7,000	16,000	28,000	38,000	48,000
Other Operating Costs	200	300	400	500	500
Maintenance	2,800	2,800	3,000	3,500	3,500
Total Cost	$12,800	$23,100	$35,800	$47,000	$ 58,000
Unit Cost, Mills/kwh	35.55	16.04	12.42	10.87	10.07
STEAM PLANT #2 - 25 Mw - Tacoma, Installed 1931 (29 Mw Peak Capability)					
Average Generation Mw	1.0	5,625	11.25	16.9	22.5
Operating Labor	$ 8,000	$10,000	$10,000	$12,000	$ 12,000
Fuel Cost @ $2.00/BBL.	5,000	25,000	45,000	65,000	85,000
Other Operating Costs	1,000	1,600	1,800	2,000	2,000
Maintenance	4,000	5,400	6,200	8,000	8,000
Total Cost	$18,000	$42,000	$63,000	$87,000	$107,000
Unit Cost, Mills/kwh	25.00	10.38	7,78	7.15	6.61

STEAM PLANT COSTS - GRAYS HARBOR PUD
Operation and Maintenance
Average Monthly Costs
1951-52

Aberdeen - Installed 1907-1928

(13.7 Mw Peak Capability)	Hot Standby	Percent of Energy Capability 25	50	75	100
Average Generation Mw	.5	3.0	6.0	9.0	12.0
Fuel Cost	$ 4,420	$22,080	$41,630	$60,300	$ 79,700
Operating Labor	4,380	4,560	4,620	5,130	5,160
Other Operating Costs	280	340	430	530	610
Maintenance	2,280	3,580	4,110	4,660	5,140
	$11,360	$30,560	$50,790	$70,620	$ 90,610
Generation Mwh	365	2,190	4,380	6,570	8,640
Unit Cost - Mills/kwh	31.1	14.0	11.6	10.7	10.5

STEAM PLANT COSTS - COWLITZ PUD
Operation and Maintenance
Average Monthly Costs
1951-52

Longview - Installed 1924-1936

	Hot	Percent of Energy Capability			
	Standby	25	50	75	100
COWLITZ (30 Mw Peak Capability)					
Generation Mw	2.0	6.75	13.5	20.25	27.0
Operating Labor	$ 8,900	$ 9,000	$ 9,400	$ 9,900	$ 10,400
Fuel Cost	18,300	46,700	93,300	140,000	186,700
Other Operating Costs	3,400	3,500	3,700	3,900	4,000
Maintenance	4,000	5,700	7,000	8,500	10,200
Total Costs	$34,600	$64,900	$113,400	$162,300	$211,300
Generation Mwh	1,460	4,928	9,855	14,783	19,710
Average Unit Cost - Mills/kwh	23.7	13.2	11.5	11.0	10.7

STEAM PLANT COSTS - EUGENE WATER & ELECTRIC BOARD
Operation and Maintenance
Average Monthly Costs
1951-52

Eugene - Installed 1931-1941

	Spinning* Reserve 8%	Percent of Energy Capability 25	50	75	100
Average Generation Mw	4.0	6.25	12.5	18.75	25.0
Operating Labor	$ 9,400	$10,000	$10,500	$11,000	$ 11,500
Fuel Cost-Wood and Oil	-	-	46,200	78,000	112,000
Fuel Cost-All Wood	8,200	12,000	24,000	36,000	48,000
Other Operation	2,200	2,500	2,600	2,750	3,000
Maintenance	6,200	6,500	7,000	8,500	10,000
Total Operation & Maintenance					
Wood and Oil	-	-	66,300	100,200	136,500
All Wood	25,600	31,000	44,100	58,200	72,500
Generation Mwh	2,920	4,500	9,000	13,500	18,000
Unit Cost - Mills/Kwh:					
Wood and Oil	-	-	7.4	7.45	7.6
All Wood	8.8	6.9	4.9	4.31	3.96

*Energy generated by cooling steam.

Miscellaneous Data:

Oil cost 2.66 bbl.
Wood cost 2.00/unit.
Peaking capacity 31,000 Kw.
Continuous capacity 25,000 Kw.
Wood readily purchased annually 60,000 units.
Wood regularly stored and available 7 months basis 6,000 units/month

If load was assured equipment could be bought and installed to greatly augment the 6,000 units per month. Now appears too speculative.

Overhead costs are omitted - experience indicates that they equal about 14% of the total maintenance and operation costs at 25% of energy capability.

"Fringe" labor costs are not included in labor costs as shown. They amount to approximately 25 cents per hour average - more than 10% of labor costs.

STEAM PLANT COSTS - PACIFIC POWER & LIGHT COMPANY

Operation and Maintenance
Average Monthly Costs
1951-52

	Hot Standby	Percent of Energy Capability 25	50	75	100
LINCOLN STATION Portland, Installed 1919-1929 (47 Mw Peak Capability)					
Average Gen. Mw	2	10	20	30	40
Operating Labor	$11,300	$12,500	$12,500	$13,500	$ 13,900
Fuel Cost	10,650	49,000	87,400	136,700	180,700
Other Operation	800	800	900	1,000	1,100
Maintenance	5,000	10,500	11,730	13,090	14,350
Total Operation & Maint.	$27,750	$72,800	$112,530	$164,290	$210,050
Generation Mwh	1,440	7,200	14,400	21,600	28,800
Unit Cost - Mills/Kwh	19.31	10.11	7.81	7.61	7.29
PITTOCK STATION Portland, Installed 1914 (4 Mw Peak Capability)					
Average Gen. Mw	0.1	0.8	1.5	2.2	3.0
Operating Labor	$ 1,050	$ 1,100	$ 1,100	$ 1,200	$ 1,200
Fuel Cost	240	1,750	3,050	4,840	6,000
Other Operation	350	400	450	500	550
Maintenance	400	830	900	1,000	1,090
Total Operation & Maint.	$ 2,040	$ 4,080	$ 5,500	$ 7,540	$ 8,840
Generation Mwh	72	576	1,080	1,584	2,160
Unit Cost - Mills/Kwh	28.40	7.08	5.09	4.76	4.09

Electric generation at Pittock Station is a by-product of supplying steam to the Steam Heat System so that generation at this station is limited as to maximum by seasonal requirements of the Steam Heat System. The above costs are based on this operation.

STEAM PLANT COSTS - PACIFIC POWER & LIGHT COMPANY
Operation and Maintenance
Average Monthly Costs
1951-52

	Hot Standby	Percent of Energy Capability 25	50	75	100
ASTORIA - Installed 1921-1938 (7.5 Mw Peak Capability)					
Average Gen. Mw	0.2	1.5	3.0	4.5	6.0
Operating Labor	$ 4,300	$ 4,300	$ 4,300	$ 4,600	$ 5,200
Fuel Cost	2,940	5,900	14,900	24,500	34,200
Other Operation	400	450	500	550	600
Maintenance	1,600	3,560	3,900	4,320	4,720
Total Operation & Maint.	$ 9,240	$14,210	$23,600	$33,970	$44,720
Generation Mwh	144	1,080	2,160	3,240	4,320
Unit Cost - Mills/Kwh	64.16	13.16	10.92	10.48	10.35

Fuel oil cost for all plants based on $2.00 posted price F.O.B. Linnton, Oregon. Hogged fuel cost delivered to furnaces estimated at $2.10 at Astoria and $2.40 at Lincoln.

STEAM PLANT COSTS - PORTLAND GENERAL ELECTRIC COMPANY

Operation and Maintenance
Average Monthly Costs
1951-52

	Hot Standby	Percent of Energy Capability (1) 25	50	75	100
STATION "L" Portland, Installed 1911-1930 (82 Mw Peak Capability)					
Average Generation Mw	1.85	13.75	27.5	41.25	55
Fuel Cost (Oil $2.05, Hog $2.10)	$15,700	$50,700	$98,300	149,900	$197,900
Operating Labor	18,000	18,000	18,000	18,500	18,500
Other Operating Cost	1,300	1,300	1,300	1,400	1,500
Maintenance	15,000	19,800	21,200	22,500	23,900
Total Cost	$50,000	$89,800	$138,800	$192,300	$241.800
Generation - Mwh	1,351	10,038	20,075	30,113	40,150
Unit Cost - Mills/kwh	37.0	8.94	6.91	6.39	6.02
STATION "E" Portland, Installed 1913-1920 (9 Mw Peak Capability)					
Average Generation Mw	-	1.25	2.5	3.75	5
Fuel Cost (Oil $2.20)	$ 3,300	$12,300	$21,600	$30,800	$ 40,300
Operating Labor	4,200	4,200	4,200	7,000	7,000
Other Operating Cost	200	200	200	200	200
Maintenance	1,200	1,500	1,700	1,800	1,900
Total Cost	$ 8,900	$18,200	$27,700	$39,800	$ 49,400
Generation - Mwh	-	912	1,825	2,738	3,650
Unit Cost - Mills/kwh	-	19.9	15.2	14.5	13.5

STEAM PLANT COSTS - PORTLAND GENERAL ELECTRIC COMPANY
Operation and Maintenance
Average Monthly Costs
1951-52

	Hot Standby	Percent of Energy Capability (1) 25	50	75	100
STATION "H" - Salem, Installed 1911 (3 Mw Peak Capability)					
Average Generation Mw	-	.5	1	1.5	2
Fuel Cost (Oil $2.60)	$ 1,300	$ 5,500	$ 9,400	$13,300	$ 17,200
Operating Labor	1,500	1,500	1,500	2,600	2,600
Other Operating Cost	100	100	100	100	100
Maintenance	800	1,000	1,100	1,200	1,300
Total Cost	$ 3,700	$ 8,100	$12,100	$17,200	$ 21,200
Generation - Mwh	-	365	730	1,095	1,460
Unit Cost - Mills/kwh	-	22.2	16.6	15.7	14.5

(1) Plants are assumed to operate at maximum peaking capability equivalent to 3 hours per day, 21 days per month.

The fuel costs for Station "L" are predicted on receiving 125,000 units of hog fuel per year and do not reflect any increased costs of burning oil for the low pressure boilers, a possible requirement if hog fuel receipts are less than that amount.

STEAM PLANT COSTS - PUGET SOUND POWER & LIGHT COMPANY

Operation and Maintenance
Average Monthly Costs
1951-52

SHUFFLETON PLANT - Renton, Installed 1929-1930
(80 Mw Peak Capability)

	Hot Standby	Percent of Energy Capability 25	50	75	100
Average Generation Mw	3	19	38	56	75
Operating Labor	$20,800	$21,700	$22,000	$22,000	$ 22,000
Other Operating Costs	1,000	1,250	1,250	1,250	1,250
Maintenance	11,200	15,600	17,900	19,100	20,400
Fuel	28,000	82,000	144,000	206,000	272,000
Total Cost	$61,000	$120,550	$185,150	$248,350	$315,650
Generation - Mwh	2,160	13,680	27,360	40,320	54,000
Unit Cost - Mills/kwh	28.2	8.8	6.8	6.2	5.8

Fuel Cost per Barrel:

Base Price	$2.00
3% Sales Tax	.06
Total	$2.06

STEAM PLANT COSTS - CITY OF SEATTLE, DEPT. OF LIGHTING

Operation and Maintenance
Average Monthly Costs
1951-52

	Hot Standby	Percent of Energy Capability 25%	50%	75%	100%
LAKE UNION PLANT - Seattle, 1914-1919 (40 Mw Peak Capability)					
Average Generation Mw	2.0	6.8	13.5	20.2	27.0
Operating Labor	$12,000	$12,000	$12,000	$13,500	$ 13,500
Fuel Cost (Oil @ $2.11 per bbl.)	22,000	52,000	95,700	137,000	176,000
Other Operating Costs	860	1,320	2,140	3,150	3,750
Maintenance	5,000	10,000	12,000	14,000	15,000
Total Cost	$39,860	$75,320	$121,840	$167,650	$208,250
Generation - Mwh	1,560	4,950	9,850	14,800	19,700
Average Unit Cost - Mills/kwh	25.55	15.22	12.37	11.33	10.57
GEORGETOWN PLANT - Seattle, Installed 1907-1917 (21 Mw Peak Capability)					
Average Generation Mw	1.0	4.0	8.0	12.0	16.0
Operating Labor	$13,500	$13,500	$13,500	$15,000	$ 15,000
Fuel Cost (Oil @ $2.265 per bbl.)	14,400	44,300	70,300	99,300	116,500
Other Operating Costs	550	875	1,400	2,075	2,575
Maintenance	5,000	7,000	9,000	12,000	15,000
Total Cost	$33,450	$65,675	$94,200	$128,375	$149,075
Generation - Mwh	730	2,920	5,840	8,760	11,680
Average Unit Cost - Mills/kwh	45.82	22.49	16.13	14.65	12.76

Note: The above costs do not include:

- Overhead Operating Costs
- Employees Welfare Operating Costs
- Depreciation
- Interest on Investment
- Insurance
- Taxes

It is the City's opinion that the first two items represent actual "out-of-pocket" costs.

<u>Possible Availability of Surplus Power for Pumping during the Winter from Run-of-the-river Plants</u>. There is a possibility that there might be intervals of surplus water coinciding with unused generating capacity during daily low load periods even in the winter months at some of the lower Columbia river run-of-the-river plants. This energy could be used to great advantage for pumping into storage for reverse flow use. This water would represent free pumped storage, even though a transfer of water instead of additional storage would be affected, unless this period should be coincident with a surplus water period at Grand Coulee. This last would be unusual; but could happen in later years with more complete river regulation.

The Army Engineers furnish the following information on this problem:

CORPS OF ENGINEERS, U.S. ARMY
Office of the Division Engineer
North Pacific Division
500 Pittock Block
Portland 5, Oregon

C O P Y

Mr. Jerome H. Johnson
Assistant Professor of Electrical Engineering
Washington State College
Pullman, Washington

Dear Mr. Johnson:

With reference to your letter of 26 March 1953 concerning dump power at Bonneville, the present operation of the Hungry Horse-Albeni Falls-Grand Coulee-Bonneville system is as you indicate; i.e. Bonneville generates to its maximum capacity limited by availability of water and Grand Coulee swings with the load demand within its ability. At the present time the Bureau is faced with a limit in the rate of change in tailwater elevation, so it isn't always possible to operate Grand Coulee as they would like. However, this problem is under study and upon arriving at a satisfactory solution, Grand Coulee may operate freely as a swing plant when so required. This condition will also be true in the Phase C level of development in that Bonneville will operate on base load and other projects will do the load factoring. In our opinion there will be no dump power at Bonneville during the off-load periods at night so long as the system resource is only sufficient to maintain firm power loads.

If we look at a system composed of Hungry Horse, Albeni Falls, Grand Coulee, Chief Joseph, McNary, the Dalles and Bonneville for a median water condition, we find only a very small amount of secondary energy in September and April, with none during the period October through March. For this system Bonneville wastes a little water in February and March and about 50,000 cfs in April due to a lack of hydraulic capacity. Thus it can be concluded that little or no dump energy would be available during winter months from this system for years of median flow or less.

Table 31 of Appendix O gives the mean monthly outputs for the Phase C system over the period 1927-42. Of the 120 winter months (September through April), the system has secondary energy available about 37% of the wintertime. However, there are only twelve months (10% of the time) when the flow at Bonneville is less than its hydraulic capacity. If it were assumed that energy could be sold on the basis of a median water year, secondary energy would be available only 18% of the wintertime, and the flow at Bonneville would exceed its hydraulic capacity in all but two months. . . .

CORPS OF ENGINEERS, U.S. ARMY
Office of the Division Engineer
North Pacific Division
500 Pittock Block
Portland 5, Oregon

C O P Y

Mr. Jerome H. Johnson
Assistant Professor of Electrical Engineering
Washington State College
Pullman, Washington

Dear Mr. Johnson:

The following data are submitted to comply with your request of 13 February 1953 pertaining to power water usage at Bonneville, McNary and Chief Joseph Dams:

Project	Number of Units	Approximate Discharge cfs
Bonneville	10	135,000
McNary	14	185,000
McNary	20(ultimate)	270,000
Chief Joseph	16	100,000
Chief Joseph	20	125,000
Chief Joseph	27(ultimate)	160,000

The figures given are based upon a maximum allowable overload of 15% above nameplate rating for Bonneville and McNary. At Chief Joseph the head, rather than the allowable overload, limits the unit output.

To summarize, there does not seem to be a possibility of obtaining dump power from Bonneville Dam. In fact, there is not much secondary power during the winter. This is as would be expected, since if there were surplus water at Bonneville during low river flow periods, Bonneville should operate at maximum capacity, allowing Coulee to drop load and fill its reservoir.

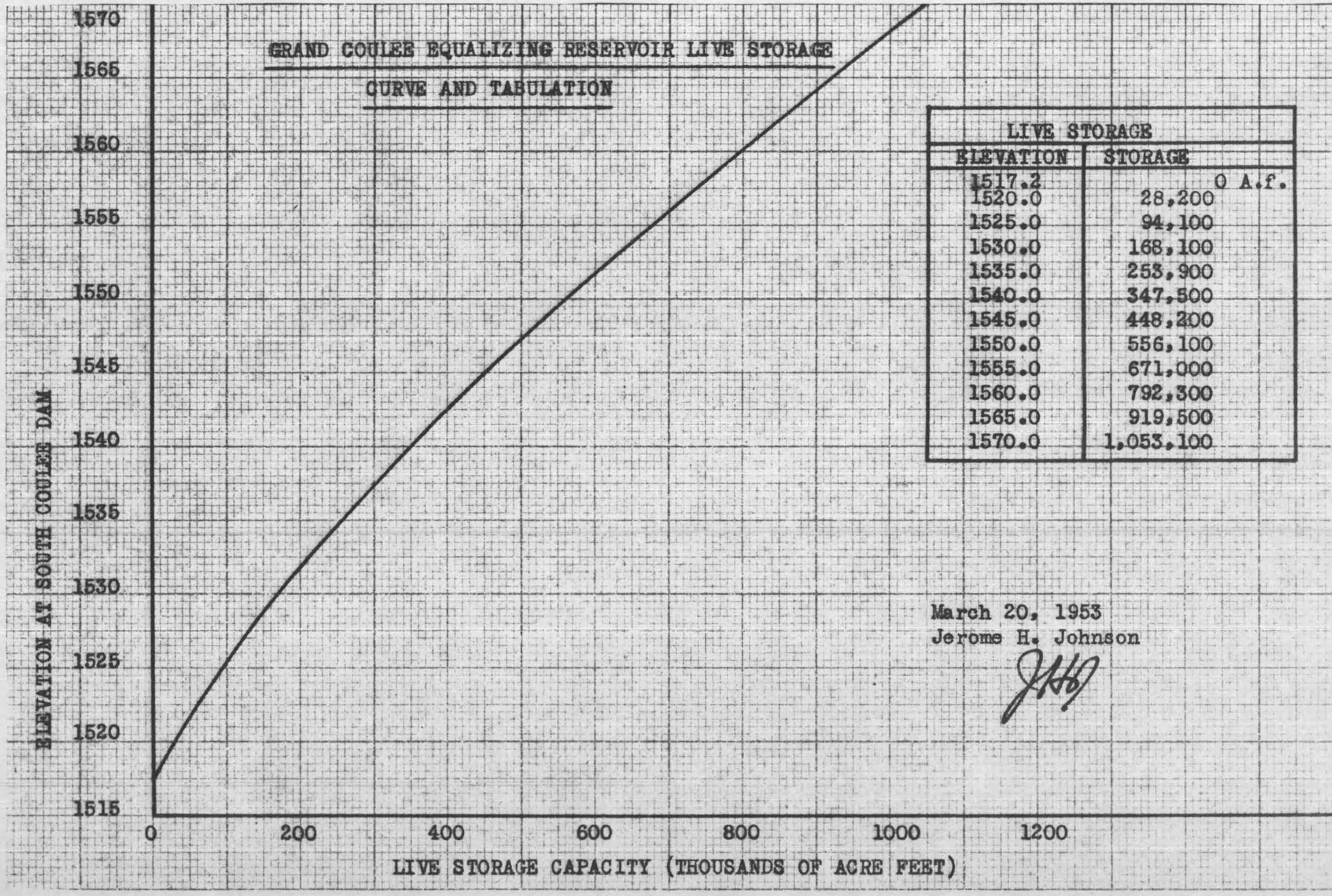
Proposed Steam and Gas Turbine Plants Proposed by the Bonneville Power Administration in their U. S. Columbia River Power System Schedule "U" - Defense Program, March 5, 1952. This program proposes the installation of 400,000 kilowatts of new fuel fired generating capacity in the Pacific Northwest. This consists of three steam-electric plants of 100,000 kw each, and five gas-turbine electric plants totalling 100,000 kw. This installation would add 400,000 kw of firm power to the Federal system.

Advantages of this type of generation are (1) to firm up hydro secondary or interruptible power supplies; (2) reduction of the amount of transmission facilities required to serve the areas in which the steam plants will operate; (3) transmission and system reserves when the plants are not required for load; and (4) faster installation than is possible for a similar amount of hydro generation. All of the plants will have a continuing place in the power operations of the region.

During the next few years or until such time as there are ample hydroelectric resources in the Federal system to serve all firm loads, the large 100,000 kw units will operate on base energy load throughout the annual storage season of October through April. Sub-

GRAND COULEE EQUALIZING RESERVOIR LIVE STORAGE

CURVE AND TABULATION



LIVE STORAGE	
ELEVATION	STORAGE
1517.2	0 A.f.
1520.0	28,200
1525.0	94,100
1530.0	168,100
1535.0	253,900
1540.0	347,500
1545.0	448,200
1550.0	556,100
1555.0	671,000
1560.0	792,300
1565.0	919,500
1570.0	1,053,100

March 20, 1953
Jerome H. Johnson
JHJ

sequently, these plants will be used for peaking and standby reserve, and will operate for energy production only if minimum hydroelectric conditions occur. For purpose of illustration, locations of the steam plants are assumed at Coos Bay, Longview, and the Olympic Peninsula. Fuel costs and transmission benefits are being analyzed for a number of locations in order to determine the most economical location. Oil, coal, and wood waste would be available for part of the fuel.

The gas-turbine electric generating plants would serve an important, though somewhat different, function than the larger units. These plants could be used to serve daily load peaks. In case of critical water conditions or in case of a transmission outage, the gas-turbines would be available for continuous operation.

Almost every other region in the United States must now depend on the expansion of thermal generating plants to meet growing electric energy requirements. The Northwest is unique in that for many years the bulk of its requirements can be met by construction hydroelectric plants capable of producing energy at very low cost. Construction of 400,000 kw of thermal plants in this region would supplement but not replace this basic source of electricity for the region (2,pp.14-15)

Cost of New Steam and New Hydro Plants.

Capitol cost of steam plants. The capital cost of steam plants is dependent on size of installation, cost of fuel, availability of condenser water supply, and design, and also on the price level for the location and the period of construction. Thus, a highly efficient plant located in territory where fuel is relatively expensive might advisedly cost considerably more per kilowatt of installation than a less efficient plant located in an area where fuel is very cheap. Other things being equal, a large plant costs less per kilowatt of installation than a small one. Similarly, other things being equal, a plant located on a river where an adequate supply of condenser water is available will cost less than one located on a divide where a spray pond must be utilized for cooling the condenser water.

In general, the cost, in 1947, of a complete steam plant in the United States varied from $100 to $200 per kw of installed capacity. A large efficient steam plant (as, say, 3 units of 165,000 kw each) cost about $150 per kw of installed capacity and a small efficient steam plant (as, say, 3 units of 10,000 kw each) should cost about $170 per kw of installed capacity.

The initial capital cost per unit of capacity is frequently higher than the above because of the provision of land, water passages, fuel-storage and fuel-handling equipment, foundations, etc., for future units, (4, pp.207-208).

Capital Cost of New Hydroelectric Plants. Here is the way non-federal hydro facilities have been developed over the last ten fiscal years: (7, p.117)

Year	(Kw)	Cost	$/Kw
1942	12,400	$ 2,426,000	$196
1943	203,600	34,010,000	
1944	149,300	23,972,000	
1945	166,600	34,455,000	
1946	2,000	789,000	
1947	194,600	49,587,000	
1948	402,900	80,730,000	
1949	132,900	19,109,000	
1950	341,400	70,257,000	
1951	777,400	184,544,000	
1952	1,410,900	363,672,000	$258
Totals	3,794,000	874,551,000	$230

<u>Reserve Capacity</u>. Reserve margins in 1953 will approximate 19% at the time of the winter peak. <u>This corresponds to the desirable margin of 20%</u>. Such comparisons are at best only rule of thumb guides since many systems now have summer peaks and some areas will be short of the desirable margins in the winter of 1953 (7, p.126).

CALCULATION.

Calculation of Per Cent Load Factors for Typical Weeks for 1950.

$$\text{Load Factor} = \frac{\text{total mw-hr for the typical week} \times 100}{\text{Maximum mw for typical week} \times \text{hr/week}}$$

Refer to the Bonneville Power Administration load data. A summation is made of all of the hourly mw readings. This gives the total mw-hr for the typical week under study. By inspecting the data, the maximum mw reading for the week under study is determined. This gives sufficient data for the calculations.

March 1950 typical week:

$$\text{Load Factor} = \frac{423,479 \times 100}{3226 \times 168} = \frac{423,479 \times 100}{542,000} = 78.1\%$$

June 1950 typical week:

$$\text{Load Factor} = \frac{393,724 \times 100}{3025 \times 168} = 77.3\%$$

September 1950 typical week:

$$\text{Load Factor} = \frac{422,456 \times 100}{3119 \times 168} = 80.75\%$$

December 1950 typical week:

$$\text{Load Factor} = \frac{474,402 \times 100}{3771 \times 168} = 74.8\%$$

It is interesting to note in the above, that the month of December has the highest mw load and highest total mw-hr. Conversely, December also has the lowest load factor.

March is also of special interest, as March represents the low water months in the typical year. This month is second high in mw load and total mw-hr energy requirement.

Calculations for the Load Duration and Peak Percentage Curves for the Northwest Power Pool.

Theory and Method:

Load Duration Curve: If one arranges in order of magnitude the hourly loads carried by a system during any given week and then plots them on a diagram with loads as ordinates and hours as abscissas, he will have a load duration curve for that week. Any desired period of time, such as a week, month, or year, may be utilized. The typical week and peak-load week for critical months are the most significant periods to use. For convenience in application to various years of the future, the load is usually plotted as a percentage of the peak load.

The area under the curve represents the total energy for the week. Among other uses the load-duration curve may conveniently be used for allocating capacity. Hydro plants with pondage, or the older and less efficient steam plants, generally take care of the upper part of the curve, which has a low load factor. If, during the week in question, flow available at the hydro plant increases, its position on the curve would be lowered and the less efficient steam plant would take its place at the top of the curve.

Peak Percentage Curve: The peak percentage curve is derived from the load duration curve as follows: A number of horizontal lines (ten are usually enough) are drawn across the diagram of the load-duration curve. Then by planimetering or some other method the total area below the curve down to each horizontal line is determined. From these data the peak percentage curve is plotted, usually with percentage of peak load measured down from the top as ordinates and percentage of total kilowatt-hours as abscissas (4, p.254).

Calculation for the Peak Percentage Curve: Use the Load Duration Curve. Measure the area under the curve down to evenly spaced horizontal lines.

The total area under the Load Duration Curve represents the total energy in kw-hr for the week under study.

The per cent of total kw-hr in the peak, as plotted on the Peak Percentage Curve is calculated as percentages of this total, using the above mentioned areas as numerators.

The total area under the Load Duration Curve is 13,162 units of energy. This is 2 x the actual number of squares as the abscissa scale must be doubled.

a) at 100% on the Load Duration Curve, or at 0% of the Peak kw, there are 0 squares under the curve, so % of total kw-hr = 0.

b) at 95% load on the Load Duration Curve, or at 5% Peak Load (measuring down from the top), the area under the curve is $24 \times 2 = 48$.

$$\frac{48 \times 100}{13{,}162} = 0.36\% \text{ of total kw-hr.}$$

c) at 90% on the Load Duration Curve, or 10% Peak kw, the area under the curve is 188 units + 48 units = 236 units.

$$\frac{236 \times 100}{13{,}162} = 1.8\% \text{ of total kw-hr.}$$

d) at 85% on the Load Duration Curve, or 15% Peak kw, the area under the curve is 564 units.

$$\frac{564 \times 100}{13,162} = 4.3\% \text{ of total kw-hr.}$$

e) at 80% on the Load Duration Curve, or 20% Peak kw, the area under the curve is 998 units.

$$\frac{998 \times 100}{13,162} = 7.6\% \text{ of total kw-hr.}$$

f) at 75% on the Load Duration Curve, or 25% Peak kw, the area under the curve is 1504 units.

$$\frac{1504 \times 100}{13,162} = 11.42\% \text{ of total kw-hr.}$$

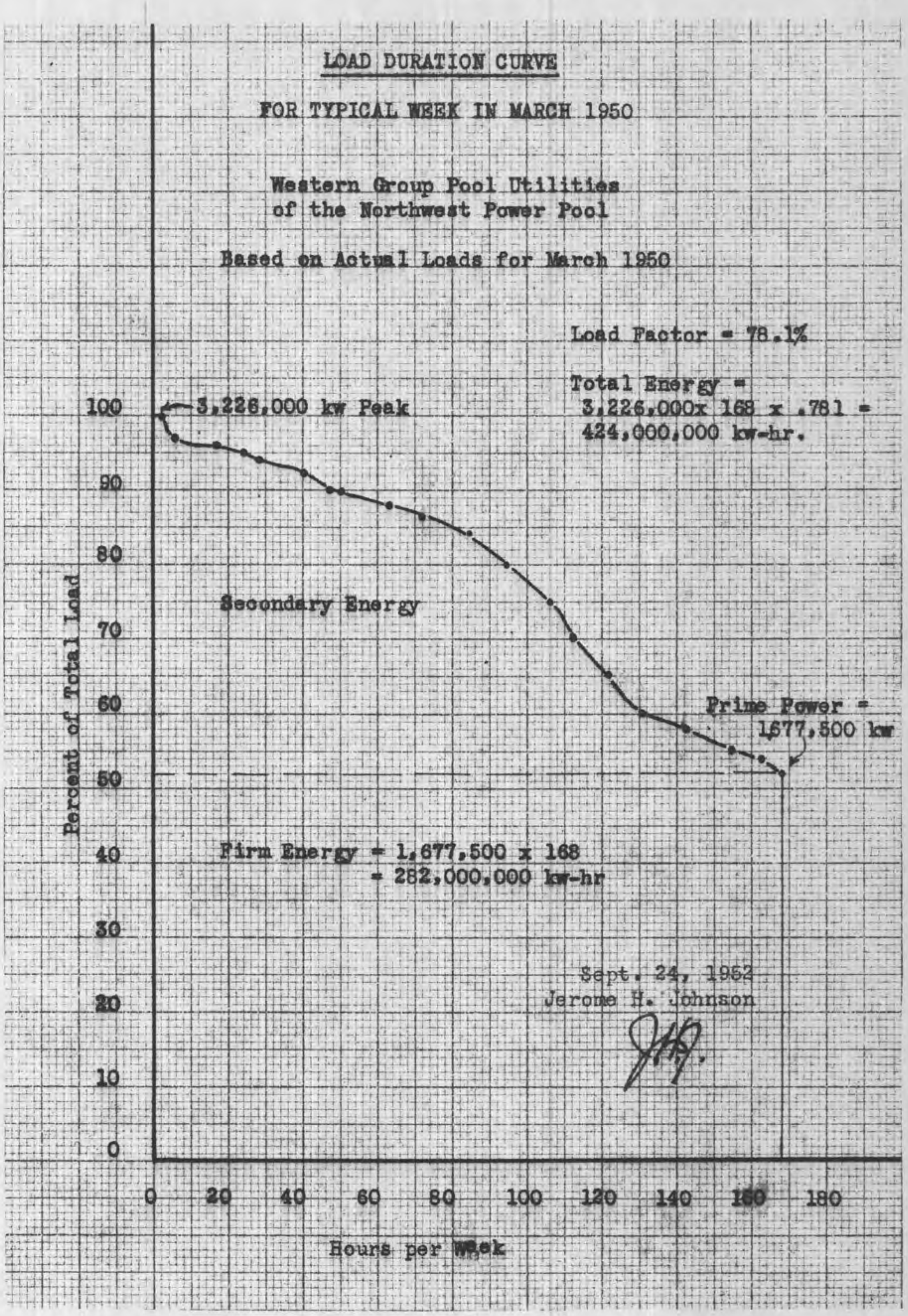
g) at 70% on the Load Duration Curve, or 30% Peak kw, the area under the curve is 2048 units.

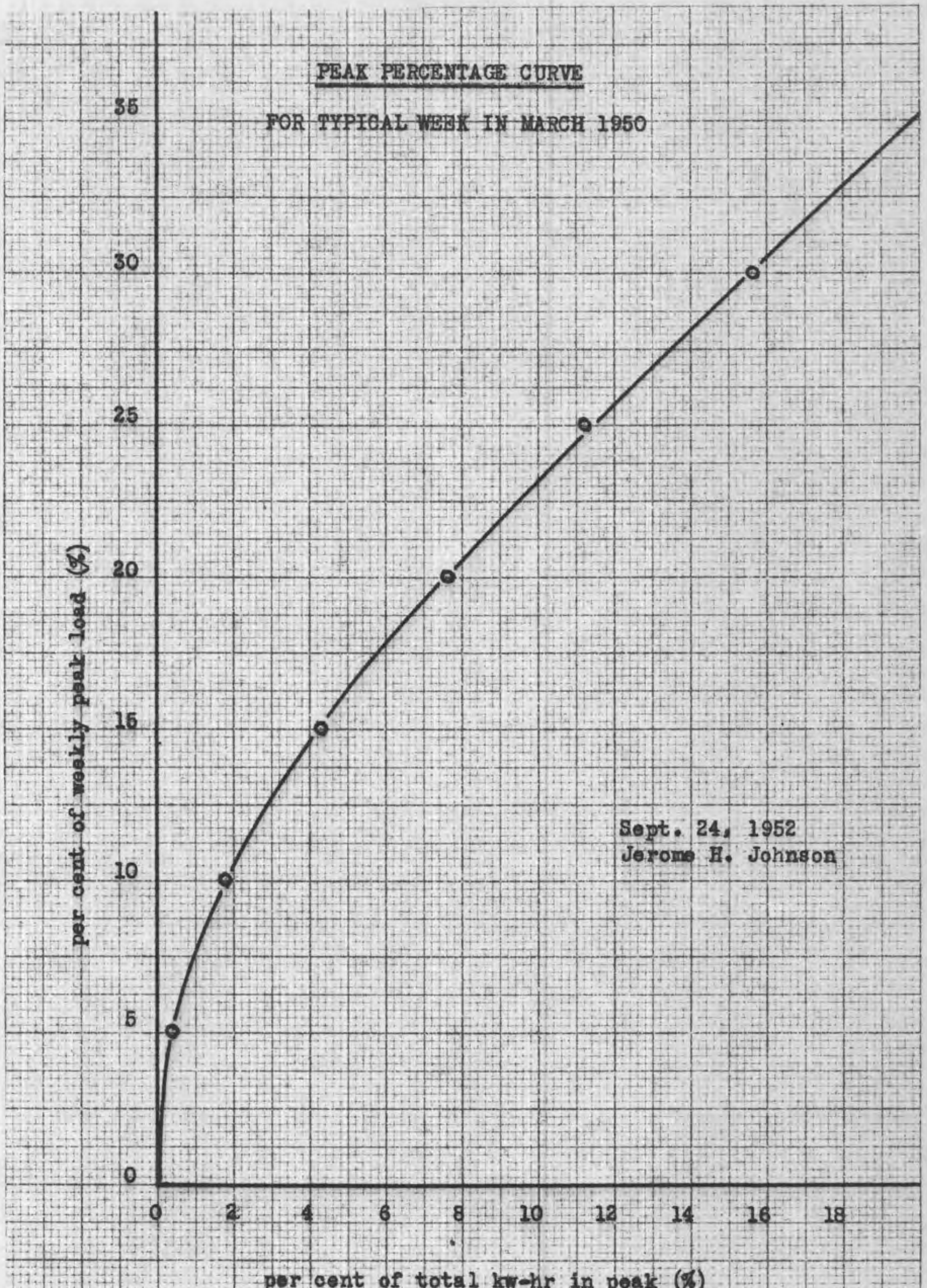
$$\frac{2048 \times 100}{13,162} = 15.6\% \text{ of total kw-hr.}$$

h) at 60% on the Load Duration Curve, or 40% Peak kw, the area under the curve is 3262 units.

$$\frac{3262 \times 100}{13,162} = 24.8\% \text{ of total kw-hr.}$$

This calculated data is plotted in the Peak Percentage Curve.


LOAD DURATION CURVE
FOR TYPICAL WEEK IN MARCH 1950
Western Group Pool Utilities
of the Northwest Power Pool
Based on Actual Loads for March 1950
Load Factor = 78.1%
Total Energy =
3,226,000x 168 x .781 =
424,000,000 kw-hr.
3,226,000 kw Peak
Secondary Energy
Prime Power =
1677,500 kw
Firm Energy = 1,677,500 x 168
= 282,000,000 kw-hr
Sept. 24, 1952
Jerome H. Johnson
JHJ.
Percent of Total Load
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120
140
160
180
Hours per Week


PEAK PERCENTAGE CURVE
FOR TYPICAL WEEK IN MARCH 1950
35
30
25
20
15
10
5
0
0
2
4
6
8
10
12
14
16
18
per cent of weekly peak load (%)
per cent of total kw-hr in peak (%)
Sept. 24, 1952
Jerome H. Johnson

<u>Calculation of Backflow in Feeder Canal</u>. The following is an explanation of the procedure used in computing the backflow curves as applied to the Feeder Canal. The terms used are given below.

Q = rate of flow in c.f.s.

B = base width of canal = 50 ft. (constant)

s.s. = side slope = $1\frac{1}{2}$:1 (constant)

d = depth of water

A = area of section of water

V = velocity at section

h_v = velocity head at section

E_s = energy surface = $d + h_v$

wp = wetted perimeter

r = hydraulic radius

n = .014 (Kutter's n)

s = slope of section considered

In order to obtain maximum discharge, the water has to go through critical velocity or depth at the outlet. In this case it would be at the beginning of the canal. Therefore, the water is considered at critical depth at station 3 + 12.12 (the outlet). The critical depth may be obtained by use of the following equation from King's Handbook of Hydraulics, page 382:

$$D_c{}^3 = \frac{b + 2ZD_c}{(b + ZD_c)^3} \cdot \frac{Q^2}{g}$$

In this case D_c = 12.85 = d.

With d known, A, V, h_v, wp, and r are readily determined. The friction slope at the section under consideration is then determined, either from tables by interpolation, or directly by formula. The notes at the right hand side of the sheets are taken from tables for interpolation.

Backflow for Feeder Canal. For the second section, d is chosen and the same procedure is followed to obtain the friction slope at the new section. The distance between the two sections is obtained by dividing the difference between E_s for the two sections by the average frictional slope plus the canal slope, or $l = \frac{\Delta E_s}{s + s_o}$ where s_o is constant at .000435.

This procedure is followed along the canal toward the reservoir until the reservoir water surface is obtained. This gives one point on the required curve. Other points are determined by taking other values of Q and following the same procedure. When conduits or tunnels are encountered, they are treated as pipes with their applicable losses.

The turnout Transition is assumed to be designed for maximum capacity of the canal, i.e. critical flow exists at Sta. 3 + 12.12 at the pump outlets.

Sta. 3 + 12.12 (Critical)

$Q = 16000$
$B = 50$
$ss = 1\frac{1}{2}:1$
$d = 12.85$
$A = 890$
$V = 17.98$
$h_v = 5.02$
$E_s = 17.87$
$WP = 95.08$
$r = 9.36$
$n = 0.014$
$s = 0.0016676$

Interpolation to obtain V at s and r

r	s .0015	.001667	.00175
9.0	16.7		18.0
9.36	17.06	17.98	18.43
9.5	17.2		18.6

$$1 = \frac{\Delta E_s}{\bar{s} + s_o} = \frac{18.36 - 17.87}{\frac{.001666 + .000972}{2} + .000435}$$

$$= \frac{0.49}{.00132 + .000435} = \frac{0.49}{.001755} = \text{279 ft. between sections.}$$

312.12 + 279.0 = 591.12 ft.

Thus, the next section considered is at 5 + 91.

<u>Sta. 4 + 91</u>

Q = 16000
B
ss
d = 15.0
A = 1087.50
V = 14.71
h_v = 3.36
E_s = 18.36
WP = 104.05
r = 10.46
n = 0.014
s = 0.000972

Interpolation to obtain V at s and r:

r	s 0.00095	.00097	.00100
10.0	14.2		14.5
10.46	14.57	<u>14.71</u>	14.89
11.0	15		15.35

$$1 = \frac{20.07 - 18.36}{\frac{.000972 + .0005}{2} + .000435}$$

$$= \frac{1.71}{.000736 + .000435} = \frac{1.71}{.001171} = \text{1460 ft. between sections.}$$

491 + 1460 = 1951

<u>Sta. 19 + 51</u>

Q = 16000
B
ss
d = 18
A = 1386.0
V = 11.54
h_v = 2.07
E_s = 20.07
WP = 114.90
r = 12.07
n = 0.014
s = 0.0005

Interpolation

r	s .0005	.00055
12.0	11.5	12.0
12.07	<u>11.54</u>	
13.0	12.0	12.6

$$1 = \frac{1.49}{.000420 + .000435} = \frac{1.49}{.000855} = \text{1744 ft.}$$

1951 + 1744 = 3695

Sta. 36 + 95

Q = 16000
B
ss
d = 20
A = 1600
V = 10.00
h_v = 1.56
E_s = 21.56
WP = 122.11
r = 13.10
n = 0.014
s = 0.000339

Interpolation

r	s .0003	.000339	.00035
13.0	9.41		10.1
13.1	9.451	10.00	10.15
14.0	9.82		10.6

$$l = \frac{1.63}{.000286 + .000435} = \frac{1.63}{.000721} = 2260 \text{ ft.}$$

3695 + 2260 = 5955

Sta. 59 + 55

Q = 16000
B
ss
d = 22
A = 1826
V = 8.76
h_v = 1.19
E_s = 23.19
WP = 129.33
r = 14.13
n = 0.014
s = 0.000233

Interpolation

r	s .0002	.000233	.00025
14.0	8.10		9.02
14.13	8.144	8.76	9.068
15	8.44		9.39

Sta. 53 + 30 (Beginning of Cut and Cover Section) by interpolation.

Q = 16000
B
ss
d
A
V
h_v
E_s = 22.74
WP
r
n
s

Elevation of Floor = 1546.48
E_s = 22.74
Elevation of Energy Gradient = 1569.22

l = length of Cut and Cover x s in Barrel + 1.0
= 2255 x 0.002229 + 1.0 = 6.03 ft.

<u>Barrel</u>

$Q = 16000$
$D = 25$
$A = 982$
$V = 16.30$
$h_v = 4.13$
$E_s = 29.13$
$r = 6.25$
$n = 0.014$
$s = 0.002229$

Interpolation

r	s 0.002	0.002229	0.003
6.2	15.4		18.9
6.25	15.5	16.30	19.0
6.4	15.8		19.3

Elevation of Energy Gradient at Sta. 53 + 30 (beginning of cut and cover section) = 1569.22

Less in the barrel = 6.03

Elevation of Energy Gradient at barrel outlet Sta. 75 + 85 = 1575.25

Sta. 75 + 85 (Extrapolation)

$Q = 16000$
B
ss
$d = 29.20$
$A = 2740$
$V = 5.84$
$h_v = 0.53$ approx.
$E_s = 29.75$
$WP = 155.25$
$r = 17.65$
$n = 0.014$
$s_M = 0.0000659$

Interpolation

r	s 0.00005	0.00010
17.0		
17.65	5.84	
18.0		

<u>Sta. 98 + 00</u> (Reservoir)

	1575.25
h_L - - - - - - - - - - =	0.20
Elevation of Energy Gradient at Reservoir	1575.45

This last figure represents the required water level at the Reservoir, required to produce a reverse flow in the Feeder Canal of 16000 cu. ft. per second. It is the uppermost point on the reverse flow curve.

The calculation is continued by finding the required reservoir elevation in exactly the same fashion for values of Q of 9600, 3200, and 1600 cu. ft. per second.

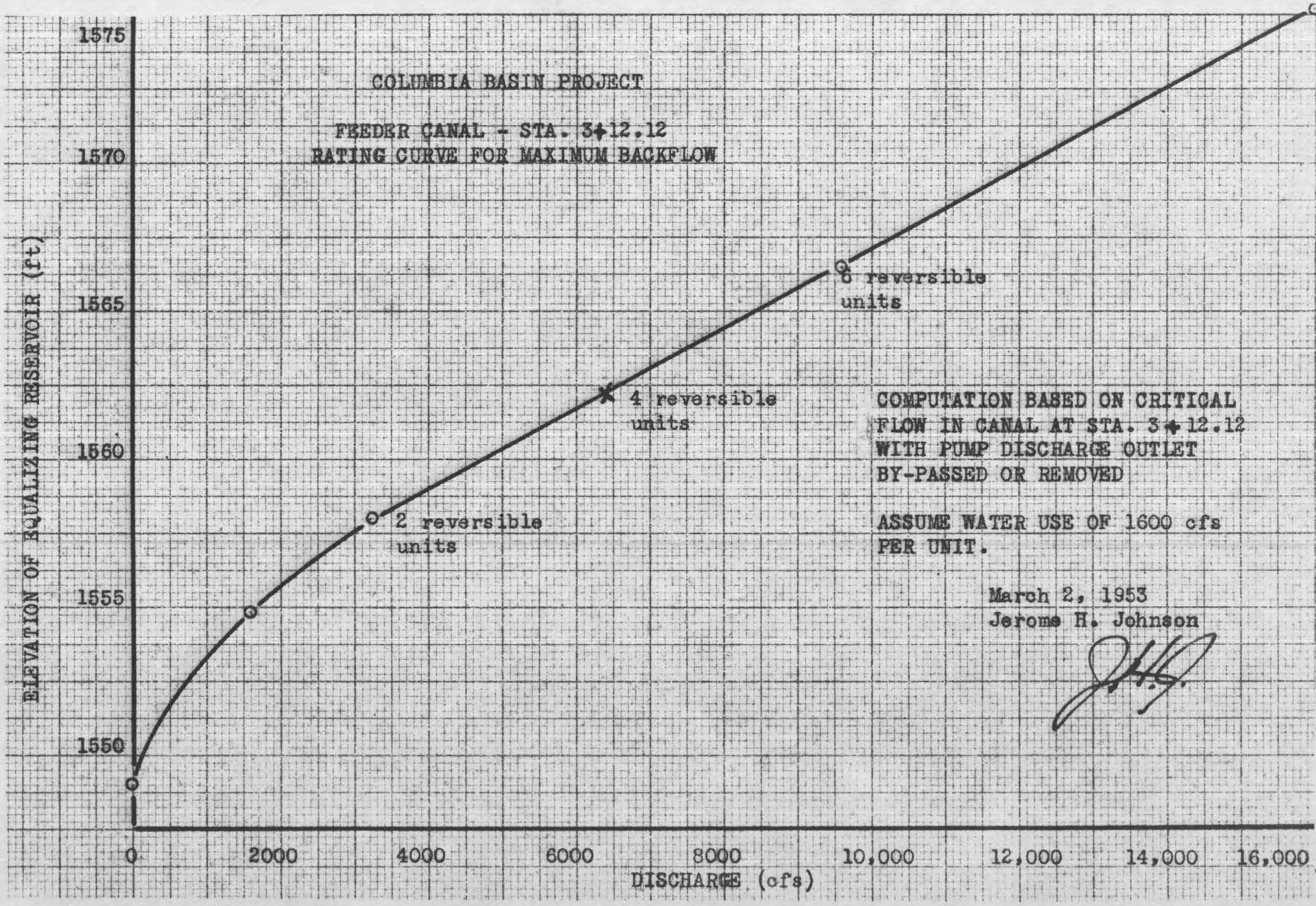
For a Q = 9600, the reservoir elevation must be 1566.42 ft.

For a Q = 3200, the reservoir elevation must be 1558.06 ft.

For a Q = 1600, the reservoir elevation must be 1554.83 ft.

The above is based on the method used for calculating canal back-flow by the Department of the Interior.

<u>Maximum Cost per kw for New Pumped Storage Plant and Maximum Price Which Can be Paid for Pumping Energy When Compared with Present Steam Plants</u>. Data has been presented on the 14 steam plants of any significant size which are operating in the Northwest. There is a wide divergence in the operating and fixed costs of the plants, so no attempt will be made at arriving at some imaginary "average" plant, but several individual plants will be studied, and the results weighed. The plants studied will be the generating station at Salem, Oregon, which has the highest cost in mills per kw-hr of all the plants, the Tacoma #1 station, which has an intermediate energy charge, and the Shuffleton Plant at Renton, Washington, which is the lowest cost plant of any in the system.


COLUMBIA BASIN PROJECT
FEEDER CANAL - STA. 3+12.12
RATING CURVE FOR MAXIMUM BACKFLOW
ELEVATION OF EQUALIZING RESERVOIR (ft)
1575
1570
1565
1560
1555
1550
DISCHARGE (cfs)
0
2000
4000
6000
8000
10,000
12,000
14,000
16,000
2 reversible units
4 reversible units
6 reversible units
COMPUTATION BASED ON CRITICAL FLOW IN CANAL AT STA. 3+12.12 WITH PUMP DISCHARGE OUTLET BY-PASSED OR REMOVED
ASSUME WATER USE OF 1600 cfs PER UNIT.
March 2, 1953
Jerome H. Johnson
JHJ

Station H, Salem Oregon

2000 kw rated, energy charge of 14.5 mills/kw-hr at rated load.

$$\begin{array}{ll} \text{Fixed operating costs} & = \$2600 \text{ per month} \\ & \quad\; 100 \\ \text{Maintenance} & = \underline{\$1300 \qquad\qquad} \\ & \quad\; \$4000 \text{ per month} \end{array}$$

$$\$4000 \times 12 \text{ mo.} = \$48{,}000 \text{ per year.}$$

$$\frac{\$48{,}000 \text{ per yr.}}{2000 \text{ kw rated}} = \$24 \text{ per kw per yr.}$$

Assume \$2.50 per kw per yr. charges for taxes and insurance. Assume 10% on the capital as the total annual cost of the pumped storage hydro plant, exclusive of the energy purchased for pumping. The maximum permissible capital cost for the pumped storage plant will then be:

$$\frac{\$24.00 + \$2.50}{10\%} = \frac{\$26.50}{.10} = \$265 \text{ per kw.}$$

Assuming an overall efficiency of the pumping plant of 65% (as at the Rocky River Plant), the maximum permissible price for purchasing energy for pumping is:

$$14.5 \times .65 = 9.425 \text{ mills per kw-hr.}$$

Similar assumptions will be made for the other two calculations. An overall efficiency of 65% is used, since the Rocky River Plant in Conn. is one of the very few pumped storage plants in the United States with a long record of operation.

Tacoma #1

8000 kw rated, energy charge of 10.07 mills per kw-hr at rated load.

$$\begin{aligned} \text{Fixed operating costs} &= \$\ 6000 \text{ per month at rated load} \\ & \quad\ \ 500 \\ \text{Maintenance} &= \underline{\quad 3500\quad} \\ & \quad \$10{,}000 \text{ per month at rated load} \end{aligned}$$

$\$10{,}000 \times 12 \text{ mo.} = 120{,}000$ per year

$$\frac{\$120{,}000 \text{ per yr.}}{8000 \text{ kw}} = \$15.00 \text{ per kw per yr.}$$

$$\frac{\$15.00 + \$2.50}{10\%} = \frac{\$17.50}{.10} = \$175 \text{ maximum permissible capital cost.}$$

10.07 mills per kw-hr x .65 = 6.54 mills per kw-hr = Maximum permissible price for purchasing pumping energy.

Shuffleton Plant, Renton, Washington

75,000 kw rated, energy charge of 5.8 mills per kw-hr at rated load.

$$\begin{aligned} \text{Fixed operating costs} &= \$22{,}000 \text{ per month at rated load} \\ & \quad\ \ 1{,}250 \\ \text{Maintenance} &= \underline{\quad 20{,}400\quad} \\ & \quad \$43{,}650 \text{ per month at rated load} \end{aligned}$$

$\$43{,}650 \times 12 = \$524{,}000$ per year

$$\frac{\$524{,}000 \text{ per yr}}{75{,}000 \text{ kw}} = \$7.00 \text{ per kw}$$

$$\frac{\$7.00 + \$2.50}{10\%} = \frac{\$9.50}{.10} = \$95 \text{ Maximum permissible capital cost for the pumped storage plant.}$$

5.8 mills per kw-hr x .65 = 3.77 mills per kw-hr = Maximum permissible price for purchasing pumping energy.

In all of the above cases, a pumped storage plant producing the same amount of energy per year as the old steam plant would produce energy at a total cost equal to the cost at the old steam plant, excluding return on the investment, if the capital cost of the pumped storage plant were equal to the maximum permissible capital cost as calculated above, and the price of off-peak energy for pumping were equal to the maximum permissible price for pumping energy as calculated for each case.

Of course, if the capital cost per kw and the energy cost for pumping is below these figures calculatedfor the existing steam plants, the pumped storage plant should be economically justified, as far as capital cost and operating cost is concerned. However, the fact that a pumped storage plant might not be able to operate as many hours per year as an old steam plant, might modify the results somewhat.

INSTALLED STEAM CAPACITY
in
Pacific Northwest

	Location	Rated MW	Peak MW	Unit Cost in mils/kwh at 100% Load
1.	Tacoma #1	8	9	10.07
2.	Tacoma #2	25	29	6.61
3.	Aberdeen	12	13.7	10.5
4.	Longview (Cowlitz)	27	30	10.7
5.	Eugene	25	27	7.6 oil & wood 3.96 wood
6.	Portland (Lincoln)	40	47	7.29
7.	Portland (Pittock)	3	4	4.09
8.	Astoria	6	7.5	10.35
9.	Portland (Station "L")	55	82	6.02
10.	Portland (Station "E")	5	9	13.5
11.	Salem (Station "H")	2	3	14.5
12.	Renton (Shuffleton Plant)	75	80	5.8
13.	Seattle (Lk. Union Plant)	27	40	10.57
14.	Seattle (Georgtown Plant)	16	21	12.76
		380 MW	469.7 MW	
		380,000 KW	469,700 KW	

More Economical Plants	Peak MW
Shuffleton	80
Station "L"	47
Lincoln	82
Tacoma #2	29
	238

(Larger plants are more economical)

Above plants kept in spinning reserve about 50% of time during normal water years.

Average mills per kw-hr for these 4 more economical plants = 6.4 mills per kw-hr.

Preliminary Cost Estimate of Modification of the Present Pumping Plant.

Alternative No. 1

Alternative No. 1 assumes the conversion of the present pumping plant at Grand Coulee for use as a pumped storage plant, using the present type of pump units. Consider only the differential in cost as compared to the final 10 pump installation which is already planned to meet irrigation needs. This alternative is discussed in some detail in the Conclusions.

1.	Modify headworks. (By-pass siphon to permit free fall, surge protection, roller gate valve installation). Very approximate.	\$2,000,000
2.	Johnson Valves. (Possibly omit.) 6 at \$100,000	600,000
3.	Transformers. (50,000 kva, 13.8 kv to 230 kv, 3 phase) 6 at \$300,000	1,800,000
4.	Main circuit breakers. (10,000 mva, 250 kv) 3 at \$120,000	360,000
5.	Generator breakers. (1000 mva, 13.8 kv, 3000 amp., 3 pole, indoor type.) 6 at \$15,000	90,000
6.	Control panels. 6 at \$7,000	42,000
7.	Possible work to correct leakage from Equalizing Reservoir. Omitted as unknown and chargable to irrigation.	
	Total	\$4,892,000

The total generating capacity for this type of modification is assumed to be 6 x 50,000 kva x 60% = 180,000 kva, as noted previously. This gives an approximate cost per kw of:

$$\frac{\$4,892,000}{180,000 \text{ kw}} = \$27.20 \text{ per kw.}$$

Alternative No. 2

Alternative No. 2 assumes the conversion of the present pumping plant at Grand Coulee Dam for use as a pumped storage plant, using an installation of 6 specially designed wicket gate pump-turbines, to be installed in the 6 remaining pump pits. Consider only the differential in cost as compared to the final 10 pump installation which is already planned to meet the predicted irrigation needs. Alternative No. 2 is discussed in considerable detail in the Conclusions.

1. Modify headworks. (By-pass siphon to permit free fall, surge protection, roller gate valve installation.) Very approximate.	$2,000,000
2. Roller gate valves at headworks. 6 at $40,000	240,000
3. Transformers. (50,000 kva, 13.8 kv to 230 kv, 3 phase) 6 at $300,000	1,800,000
4. Main circuit breakers. (10,000 mva, 250 kv) 3 at $120,000	360,000
5. Generator breakers. (1000 mva, 13.8 kv, 3000 amp., 3 pole, indoor type.) 6 at $15,000	90,000
6. Control panels. 6 at $10,000	60,000
7. Pump-turbines. Cost differential on 4 units: $600,000 new minus $300,000 present type = $300,000; 4 at a difference in cost of $300,000	1,200,000
Total price on 2 reversible units beyond present planned total of 10 pumps: 2 at $600,000	1,200,000
8. Motor-generators. Total price on 2 units beyond present planned total of 10 pumps: 2 at $450,000	900,000

Two speed windings will not be considered for the motor generators, due to their high cost and low use per year.

9. Possible work to correct leakage from the Equalizing Reservoir. Omitted as unknown and chargable to irrigation.

This gives a total cost of modification of the pumping plant for Alternative No. 2 of approximately \$7,850,000.

The total generating capacity for this alternative has been calculated and assumed to be approximately 256,000 kva, as noted previously. This gives an approximate cost per kw of:

$$\frac{\$7,850,000}{256,000 \text{ kw}} = \$30.90 \text{ per kw}$$

The present 65,000 hp motors were purchased at a cost of \$437,000 each installed, from the Westinghouse Electric Corp. This price should not have changed greatly.

Although the Allis Chalmers Co. points out that a considerable advantage in pump-turbine efficiency can be gained by using a 2 speed motor-generator, the cost of this is very high, and will not be considered here, due to the low use factor of the installation. A 2 speed motor-generator is more expensive than the sum of the 2 independent units.

The present pumps were obtained at a cost of \$177,000 each plus an installation cost of \$42,000 each. However, from discussion with the Pelton Water Wheel representatives, this price was too low and would be considerably higher if subsequent units were ordered. Therefore, a figure of \$300,000 is assumed.

Governor control may be assumed for Alternative No. 2. This was omitted from the cost estimate, as no data was available.

Estimated prices for circuit breakers, generator breakers, motor-generators, and transformers are based on figures from Westinghouse Electric Corp. representatives, and are not quotations.

Ability of the Ultimate Installation of 10 Pumping Units to Furnish or Surpass the Predicted Ultimate Irrigation Water Requirements. In the calculation which follows the minimum number of pumping days required to fill the irrigation water needs will be solved for.

If the average pumpage per pump is taken at the maximum figure of 1600 c.f.s., as the present pumps are rated at their minimum pumping head of 280 ft, a minimum figure will be found. This head may not be actually possible during the entire pumping season, although Lake Roosevelt should be at or near its maximum elevation during about all of the period of pumping considered. This calculation will be made for a pump output of 1600 c.f.s., and a lower output of 1450 c.f.s., which might prove to be a fair average. Only the minimum head calculation will be shown.

Assume a pump output of 1600 c.f.s.

There are $60 \times 60 \times 24 = 86{,}400$ seconds per day

$1600 \times 86{,}400 = 138{,}300{,}000$ cubic ft. per day per pump unit

1 acre-ft. = 43,650 cubic ft.

$$\frac{138{,}300{,}000 \text{ cu. ft./day/pump}}{43{,}650 \text{ cu. ft./acre ft.}} = 3{,}170 \text{ acre-ft./day/pump}$$

The predicted minimum ultimate irrigation water requirement = 3,634,500 acre-ft./year

$$\frac{3{,}634{,}500 \text{ acre-ft/yr.}}{3{,}170 \text{ acre-ft./pump/day}} = 1145 \text{ pump-days required to meet minimum requirements.}$$

Assuming 10 pumps, 114.5 pumping days are required.

If a pump outage for the 10 pumps of 10% is assumed.

$114.5 + 11.45 = 126$ days of pumping are required to meet the predicted ultimate irrigation water requirements.

If an average pump output of 1450 c.f.s. were assumed, a solution similar to the above shows that a total of 139.2 pumping days are required for 10 pumps to meet the predicted ultimate irrigation water requirements.

In evaluating these two values, atleast two factors must be considered:

1) The limitation of the Feeder Canal on the rate of pumping has been neglected as an unknown factor in all of the above calculation. As shown in previous calculations, the Feeder Canal becomes a definite limitation to the flow in both directions, although less serious and only at upper elevations of the Equalizing Reservoir for pumping. The Equalizing Reservoir Operating Curve shown in Data, gives predicted reservoir elevations through the year 1961, and at least indicates that the Equalizing Reservoir is expected to be completely filled once a year to meet irrigation needs alone. As the reservoir approaches the upper elevation of 1570 ft., the Feeder Canal will limit pumping to 8 units at 1565.5 ft., to 6 units at 1567.6 ft., 4 units at 1569 ft., and 2 units at 1569.8 ft. elevation. This limitation should not be serious over a very great portion of the pumping season, but cannot be neglected, and will surely reduce the average pumping rate below the possible maximum of 1600 c.f.s.

2) A pump output of 1600 c.f.s. is only possible for minimum pumping head, or when Lake Roosevelt is at its upper elevation. This would not be the case throughout the entire pumping period, especially

at the very first and last of the pumping season.

With the above factors in mind, 1600 c.f.s. seems to be a somewhat optimistic figure, and the output value of 1450 c.f.s. per pump may be somewhat pessimistic.

To be on the conservative side, the figure 139 pumping days will be used, based on the pessimistic average pump output of 1450 c.f.s.

Analysis of River Flow Data - Regulated and Unregulated - to Determine the Periods of Excess Flow at Grand Coulee Dam. The maximum rated water capacity of each turbine at Grand Coulee Dam is approximately 5,000 cfs at an average head. This gives a maximum total power-house rating of 18 x 5000 = 90,000 cfs. Since the load factor of the Northwest Power Pool is generally in the order of 78% to 82%, the average power-house use should be considered to be some lower figure. An average power-house use of 75,000 cfs will be assumed for the present installation of 18 turbines.

The predicted effect of a third power-house at Grand Coulee is also of interest. While this is in the speculation and planning stage, its possible effect can easily be studied. If 9 additional units of the present size were to be installed this would give a total maximum water capacity of 90,000 + (9 x 5000) = 135,000 cfs. An average total power-house use of 110,000 cfs will be assumed.

The data compiled below are taken from the Columbia River flow curves in the Data. The data for the River regulated to the Phase C or C-2 condition, are taken from the same section, referring to the curves from the Army 308 Report, Appendix O.

	Excess Flow Period, Assuming Present Average Power-house Use of 75,000 cfs.		Excess Flow Period Assuming Average Flow with Third Power-house of 110,000 cfs.	
Year	Unregulated	Regulated to Phase C	Unregulated	Regulated to Phase C
1914	170 days		134 days	
1915	166		144	
1916	208		164	
1917	150		120	
1918	188		140	
1919	180		136	
1920	188		118	
1921	166		132	
1922	160		124	
1923	166		132	
1924	140		98	
1925	176		142	
1926	152		96	
1927	246		154	
1928	186	210 days	124	150 days
1929	134	150	98	30
1930	166	150	128	30
1931	150	180	104	30
1932	176	180 summer, 60 winter	138	90
1933	168	210 summer, 60 winter	136	75
1934	186	210 summer, 90 winter	136	90

Year	Excess Flow Period, Assuming Present Average Power-house Use of 75,000 cfs. Unregulated	Regulated to Phase C	Excess Flow Period Assuming Average Flow with Third Power-house of 110,000 cfs. Unregulated	Regulated to Phase C
1935	166	150 summer, 120 winter	116	90
1936	154	150 summer, 30 winter	114	60
1937	140	180	100	15
1938	164	150	116	105
1939	164	150	116	60
1940	152	150 summer, 30 winter	104	60
1941	188	240 summer, 30 winter	66	60
1942	154	180	116	90
1943	160		132	
1944	120		64	
1945	122		96	
1946	172		120	
1947	168		118	
1948	152		126	
1949	138		108	

The effect of river regulation by dams upstream from Grand Coulee is very noticeable. It produces two major effects by smoothing out the yearly river flow curves. The peak flow in the summer run-off period is not as high as for the unregulated case, as the dams upstream are filling up their reservoirs at this time. The second effect is in maintaining a higher minimum flow throughout the winter months when the flow is naturally much lower than during the summer.

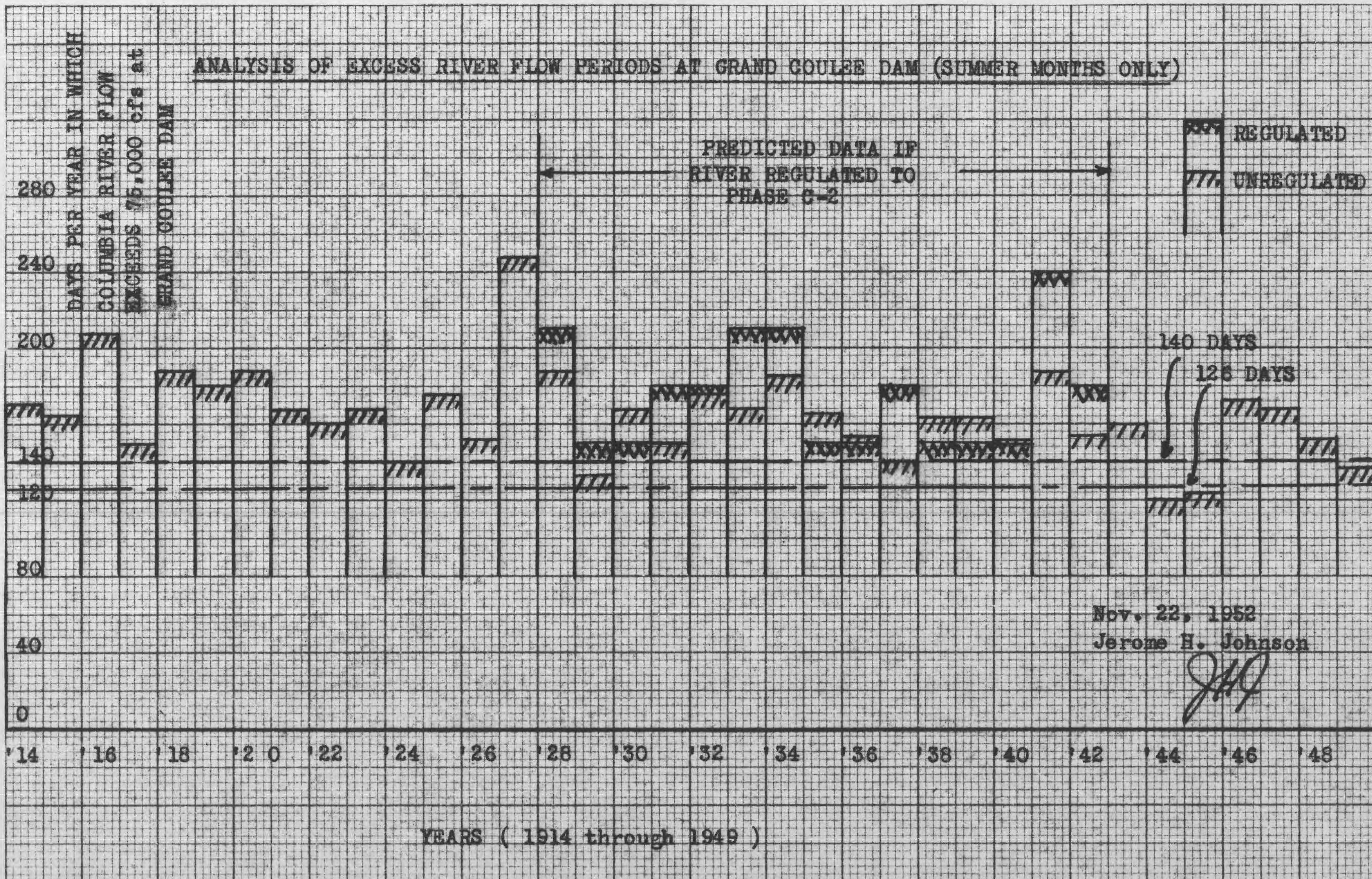
This is, of course, one of the main functions of river regulation, being valuable in both power generation and in flood control.

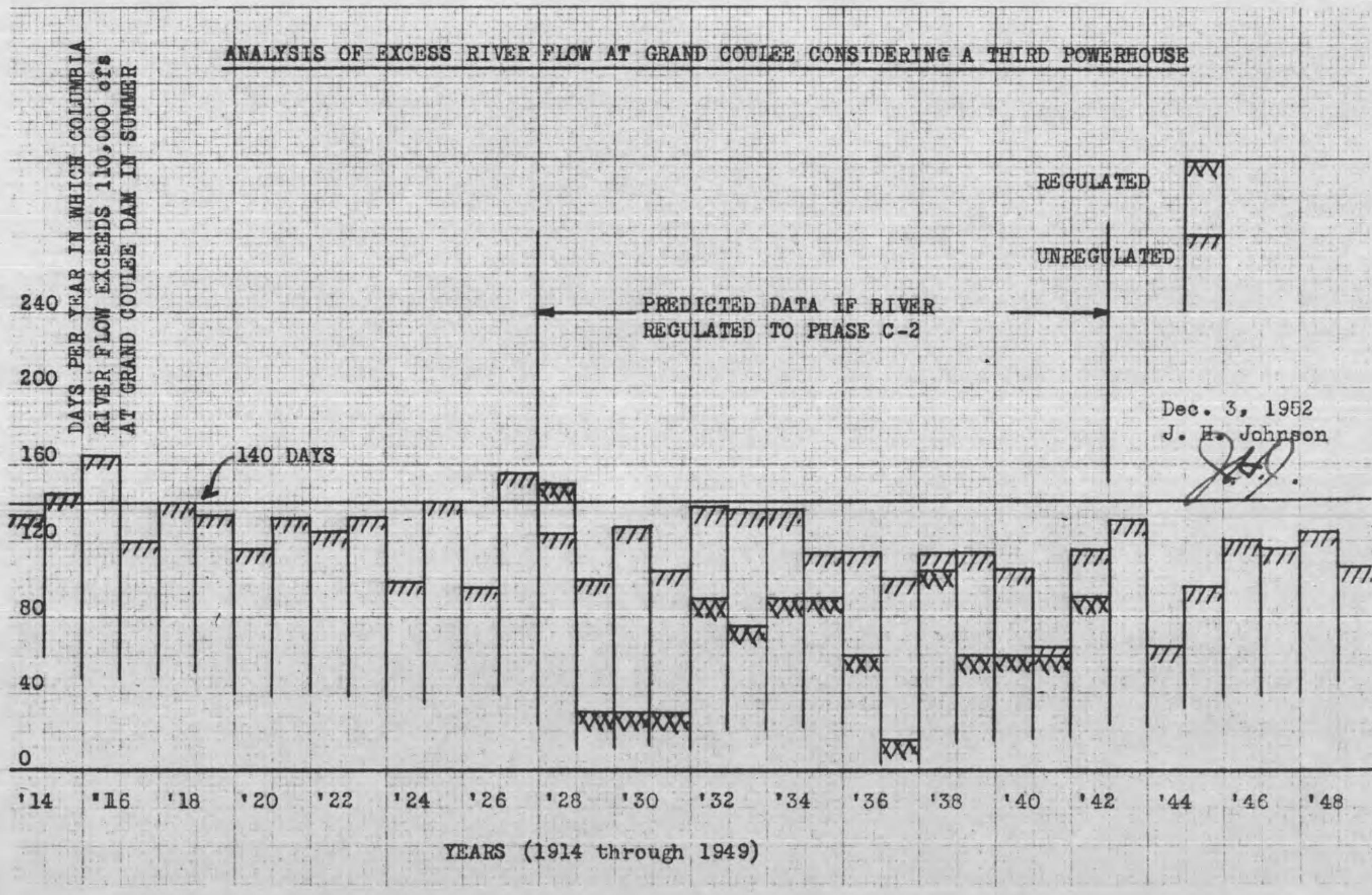
To illustrate the degree of control expected by Phase C or C-2 regulation, in the 1928 to 1942 period, 13 out of the 15 years show the river flow decreasing below a river flow of 50,000 cfs at some period of the year. In the same period, for the river regulated, not one year shows a predicted river flow having decreased to this value.

The average flow for the period during which the regulated river was studied, shows an average minimum for the 1928 to 1942 period of between 60,000 and 70,000 cfs. during the low water months of October through March. This figure compares favorably with the average power-house use figure of 75,000 cfs.

<u>The Average Period of Excess Flow Beyond that Required to Meet Ultimate Predicted Pumping Requirements</u>. Although the average period of excess flow beyond the 140 day minimum required to meet ultimate pumping requirements has no exact significance, it does show that in a large number of the years, for both the River unregulated and regulated, there is sufficient <u>time</u> to accomplish a very significant amount of pumping beyond that needed for irrigation. Whether this water can be stored, as limited by storage facilities and the time of pumping and draw-down is another matter, which will be discussed later.

From an examination of the River flow data, it can be found that the average number of days per year beyond the 140 days required to meet the ultimate predicted irrigation requirements, only con-


ANALYSIS OF EXCESS RIVER FLOW PERIODS AT GRAND COULEE DAM (SUMMER MONTHS ONLY)
DAYS PER YEAR IN WHICH COLUMBIA RIVER FLOW EXCEEDS 75,000 cfs at GRAND COULEE DAM
PREDICTED DATA IF RIVER REGULATED TO PHASE C-2
REGULATED
UNREGULATED
140 DAYS
126 DAYS
280
240
200
140
120
80
40
0
'14
'16
'18
'20
'22
'24
'26
'28
'30
'32
'34
'36
'38
'40
'42
'44
'46
'48
YEARS (1914 through 1949)
Nov. 22, 1952
Jerome H. Johnson
JHJ


ANALYSIS OF EXCESS RIVER FLOW AT GRAND COULEE CONSIDERING A THIRD POWERHOUSE
DAYS PER YEAR IN WHICH COLUMBIA RIVER FLOW EXCEEDS 110,000 cfs AT GRAND COULEE DAM IN SUMMER
REGULATED
UNREGULATED
PREDICTED DATA IF RIVER REGULATED TO PHASE C-2
140 DAYS
Dec. 3, 1952
J. H. Johnson
240
200
160
120
80
40
0
'14
'16
'18
'20
'22
'24
'26
'28
'30
'32
'34
'36
'38
'40
'42
'44
'46
'48
YEARS (1914 through 1949)

sidering the summer excess flow periods is:

25.3 days per year for the River unregulated.

36.0 days per year for the River regulated to Phase C.

Volume of Water Which Could be Pumped During this Average Unused Excess Flow Period.

Columbia River Unregulated:

Assume an average pump output of 1450 cfs, as a conservative figure, and as used before.

1450 cfs x 60 sec. x 60 min. x 24 hr. = 1450 x 86,400 = 125,300,000 cubic ft. per day per pump.

1 acre ft = 43,580 cu ft. Assume a pump outage of 10%

In an average year for the river unregulated,

$$\frac{25.3 \text{ days} \times 125{,}300{,}000 \times 9 \text{ pumps}}{43{,}580} = 654{,}000 \text{ acre ft possible reservoir}$$

pumpage beyond the ultimate irrigation water requirements.

Columbia River Regulated to Phase C:

Assume an average pump output of 1450 cfs, and consider only excess flow during the summer run-off period. Assume a pump outage of 10%. The figure of 125,300,000 cubic ft per day per pump is still correct. In an average year for the river regulated,

$$\frac{36 \text{ days} \times 125{,}300{,}000 \times 9 \text{ pumps}}{43{,}580 \text{ cu ft/acre ft.}} = 932{,}000 \text{ acre ft possible reservoir}$$

pumpage beyond the ultimate irrigation water needs.

Since the total reverse flow draw-down, as limited by the Feeder Canal, is equal to 382,100 acre ft. these two figures are by no means negligible.

Comparison of Water Use in Kw-hr per Gallon of Water Directly Through Grand Coulee Main Turbines, or from Pumped-Storage. At Grand Coulee, each main turbine takes 141 tons per second of water at rated load. This is 141 x 2000 = 282,000 lb. per sec. per turbine. At rated load, the turbine is furnishing power to generate 108,000 kw per sec.

As 1 cu. ft. of water weighs 62.43 lb,

then, 282,000 lb./sec. = 282,000/62.43 = 4520 cu. ft./sec./turbine.

So, 4520 cu. ft. of water dropped over Coulee in 1 sec. produces 108,000 kw-sec.

Each pump delivers 1600 cu. ft./sec. at a head of 280 ft. by rating

Each pump motor takes $\frac{65,000 \text{ hp}}{97\% \text{ efficiency}}$ x .746 = 50,000 kva input.

108,000 kw-sec from the Grand Coulee turbines will drive 1 pump for

$\frac{108,000}{50,000}$ = 2.16 seconds. (Neglect bus losses)

This will pump 2.16 x 1600 cu. ft/sec. = 3460 cu. ft. of water.

Now, if the water should be dropped back into Lake Roosevelt from the Equalizing Reservoir, it is required to find how much energy could be generated. It will be assumed, as suggested by Dr. Robert T. Knapp of California Institute of Technology who was consultant for Byron-Jackson, the pump designers, that the efficiency of the present pumps operated reversibly as turbines should be within 1 or 2% of that as for pump use. Also, assume that no evaporation or leakage has occurred in the Equalizing Reservoir, and that the elevation of

Lake Roosevelt is unchanged. It can be assumed without appreciable error that the water will flow reversibly at about the same velocity and volume as in the pumping operation.

Thus, 3460 cu. ft. of water will flow reversibly in a period of 2.16 seconds.

Investigate the Head Loss in the penstock.

The head loss for clean iron pipes is given by $h_1 = \frac{.02\ L\ V}{64.4\ D}$

where: L = length of pipe in ft.

V = velocity in ft./sec.

D = diameter of pipe in ft.

The volume of the output is 1600 cu. ft. sec. through the 12 ft. diameter pipe. Dimensionally, volume in ft.^{3}/sec. can be written as ft.^{2} x ft./sec. = A x Vel.

$$\text{Velocity} = \frac{\text{Volume per sec.}}{\text{Area}} = \frac{\text{Area x Velocity}}{\text{Area}} = \frac{1600}{\pi 6^2} = 14.1 \text{ ft./sec.}$$

$$\text{head loss} = \frac{.02\ L\ V}{64.4\ D} = \frac{.02\ (350)\ (14.1)}{64.4\ (12)} = 0.128 \text{ ft.}$$

Thus, the head loss is negligible.

The horse-power obtained for a given power drop is given by the equation:

$$hp = \frac{62 \times A \times V \times H}{33{,}000}$$

, where H = head in ft.
V = velocity in ft/minute
A = area in sq. ft.

A x V = volume/sec. = 16,000 ft.^{3}/sec. H = 280 ft.

= 16,000 x 60 = 96,000 ft.^{3}/minute

$$hp = \frac{62 \times 96{,}000 \times 280}{33{,}000} = 50{,}600 \text{ hp.}$$

Generator output = output from power drop - losses of turbine and generator

$$= 50{,}600 - \underbrace{(50{,}600 \times .03)}_{\text{Generator loss}} - \underbrace{(50{,}600 \times .10)}_{\text{Turbine loss}}$$

$$= 50{,}600 - 1518 - 5{,}060$$

$$= 50{,}600 - 6{,}578 = 43{,}022 \text{ hp}$$

In the above, the generator efficiency is assumed to be 97%, and the turbine efficiency to be 90%. These are on the optimistic side, if anything.

Converting output to kw:

Generator output = 43,022 x 0.764 = 32,900 kw.

It will be assumed that this output occurs for 2.16 seconds, the period needed to pump up a similar volume.

32,900 kw x 2.13 = 71,100 kw-sec.

This is compared to the 108,000 kw-sec. required to pump the water up into the reservoir. This gives an overall efficiency for the operation of

$$\text{Efficiency} = \frac{71{,}100 \times 100}{108{,}000} = 66.6\%$$

From the above, it is very clear that from the standpoint of kw-hr. per gallon of water, or water efficiency, that any system of pumped storage in an all hydroelectric system is at a disadvantage. With a given supply of water, this might be the determining factor. In a steam and hydroelectric power system, where pumping is done with off-peak steam energy, this problem does not arise.

Use of Present Type of Pump Units Reversibly as Turbines.

A. 1) Data on the number of reversible units of the present type which can be operated at different Equalizing Reservoir elevations. 2) The KVA output from these units.

B. Hours and kw-hr of operation possible at each point for 6, 4, 2, and 1 units operating as limited by the Feeder Canal.

C. Optimum methods of operation to utilize available kw and kw-hr most effectively.

A.

1. The Equalizing Reservoir elevation necessary to provide sufficient backflow to operate a given number of pump units reversibly as turbines, is taken from the Feeder Canal Backflow Curve, contained in the Data . It is assumed that the reverse flow volume of the units is the same as for pump action.

2. The capacity of the pump units operating as turbines is considerably reduced from their horse-power rating as pumps. Dr. Knapp of the California Institute of Technology has acted as a consultant for the Byron-Jackson Co. who designed the present pump units. In correspondence with him, he has suggested that the rating for the units operating reversibly might be assumed to be approximately 60% of their rating as pumps. This figure will be assumed in the following calculations.

<u>1 Pump Unit Operating Reversibly</u>:

1 unit can operate to an Equalizing Reservoir elevation of 1555, or for a drawdown of 1570 - 1555 = 15 ft.

The pump driving motors have a rating of 65,000 hp, or 50,000 kva.

50,000 x 60% = 30,000 kva per unit operating reversibly.

<u>2 Pump Units Reversibly</u>:

2 units can operate to a reservoir elevation of 1558.0 ft., or a drawdown of 1570 - 1558 = 12 ft.

2 x 50,000 x .60 = 60,000 kva.

<u>4 Pump Units Reversibly</u>:

4 units can operate to a reservoir elevation of 1562.5 ft., or a drawdown of 1570 - 1562.5 = 7.5 ft.

4 x 30,000 = 120,000 kva.

<u>6 Pump Units Reversibly</u>:

6 units can operate to a reservoir elevation of 1566.7 ft., or a drawdown of 1570 - 1566.7 = 3.3 ft.

6 x 30,000 = 180,000 kva.

B.

<u>6 Pump Units Reversibly</u>:

1570 to 1566.7 ft. drawdown represents	1,053,100 acre-ft.
	- 940,000 acre-ft.
	113,100 acre-ft.

The above values were obtained from the Rating Curve of the Equalizing Reservoir as shown in the Data.

1 acre-ft. = 43,580 cubic ft.

so, 113,100 x 43,580 = 4,940,000,000 cubic ft. of water available in the upper 3.3 ft. of drawdown from the Equalizing Reservoir. Assume the same water capacity for pump and turbine action. This is 1600 cu. ft. per second at 280 ft. head. This represents 1600 x 3600 = 5,760,000 cu. ft./hour, per pump.

$$\frac{4,940,000,000}{5,760,000} = 857 \text{ hours of operation per pump}$$

For 6 pumps operating, this is $\frac{857}{6} = 143$ hr.
Thus, 180,000 kva can be generated for 143 hr. or, 143 x 180,000 = 25,750,000 kw-hr of energy.

This is a rather doubtful increment of energy, however, as there are 2 major drawbacks to be considered. a) The possible effect of a known but unfathomed fault in the floor of the Equalizing Reservoir, which may make holding the reservoir at the upper limit of its elevation impossible or impractical. b) Slow pumping at the upper limit of the Reservoir, as limited by the Feeder Canal, makes filling the reservoir to the full point a problem in time, where time may be the determining factor as it is related to surplus water flow periods.

This is unfortunate, as this increment is most valuable of all, as it has the greatest allowable generating capacity, and thus the greatest peaking potential.

It is interesting to note that $\frac{113,100 \text{ acre-ft.}}{382,100 \text{ acre-ft.}} = 40\%$ of the power potential of the Equalizing Reservoir in acre-ft. available for use for reverse flow through the present Feeder Canal, is contained in this top 3.3 ft. of reservoir capacity.

Consider operating 4 units reversibly in two different ways:

a) Operating 4 units all of the time from the Reservoir full condition until 1562.5 ft. elevation is reached.

b) Operating 6 units to a drawdown of 1566.7 ft., and then 4 units to a drawdown of 1562.5 ft. elevation.

a) 1570 to 1562.5 ft. = 1,053,100 acre-ft.
$\underline{-\ 850,000 \text{ acre-ft.}}$
203,100 acre-ft.

203,100 x 43, 580 = 8,860,000 cu. ft. of water available.

$\frac{8,860,000,000}{5,760,000}$ = 1538 hours of operation per unit.

$\frac{1538}{4}$ = 384 hours of 4 unit operation, from reservoir full to 1562.5 ft.

384 x 120,000 = 46,600,000 kw-hr of energy.

b) 1566.7 to 1562.5 ft. = 940,000 acre-ft.
$\underline{-850,000 \text{ acre-ft.}}$
90,000 acre-ft.

90,000 x 43,580 = 3.93×10^9 cu. ft.

$\frac{3.93 \times 10^9}{5.76 \times 10^6}$ = 682 hr. per pump

$\frac{682}{4}$ = 170.5 hr. of operation for 4 units, operating from point where 6 units are limited to where 4 units are limited by the Feeder Canal.

170.5 x 120,000 = 20,400,000 kw-hr of energy.

Consider operating 2 units reversibly in two different ways:

a) Operating 2 units all of the time from the Reservoir full condition until 1558 ft. elevation is reached.

$$\begin{aligned} 1570 \text{ to } 1558 \text{ ft.} &= 1{,}053{,}100 \text{ acre-ft.} \\ &\underline{-\ 740{,}000 \text{ acre-ft.}} \\ &\quad\ 313{,}100 \text{ acre-ft.} \end{aligned}$$

$313{,}100 \times 43{,}580 = 13.65 \times 10^9$ cu. ft.

$\frac{13.65 \times 10^9}{5.76 \times 10^6} = 2.37 \times 10^3 = 2370$ hr. per pump unit.

$\frac{2370}{2} = 1185$ hr. of operation.

$1185 \times 60{,}000 = 71{,}000{,}000$ kw-hr.

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b) Operating 2 units from point where 4 units are limited until 1558 ft. elevation is reached.

$$\begin{aligned} 1562.5 \text{ to } 1558 \text{ ft.} &= 850{,}000 \text{ acre-ft.} \\ &\underline{-740{,}000 \text{ acre-ft.}} \\ &\quad 110{,}000 \text{ acre-ft.} \end{aligned}$$

$110{,}000 \times 43{,}580 = 4.80 \times 10^9$ cu. ft.

$\frac{4.80 \times 10^9}{5.76 \times 10^6} = 832$ hr. per unit.

$\frac{832}{2} = 416$ hours of operation.

$416 \times 60{,}000 = 25{,}000{,}000$ kw-hr.

Consider operating 1 unit reversibly in two different ways:

a) Operating 1 unit all of the time from the Reservoir full condition until the 1555 ft. elevation is reached, at which point the Feeder Canal limits further operation.

$$\begin{aligned} 1570 \text{ to } 1555 \text{ ft.} &= 1{,}053{,}100 \text{ acre-ft.} \\ &\underline{-\ 671{,}000 \text{ acre-ft.}} \\ &\quad\ 382{,}100 \text{ acre-ft.} \end{aligned}$$

$382{,}100 \times 43{,}580 = 16.65 \times 10^9$ cu. ft.

$\frac{16.65 \times 10^9}{5.76 \times 10^6} = 2{,}890$ hr of operation.

$2890 \times 30{,}000 = 86{,}700{,}000$ kw-hr.

---

b) Operating 1 unit from the point where 2 units are limited until 1555 ft. elevation is reached.

1558 to 1555 ft. = 740,000 acre-ft.
-671,000 acre-ft.
69,000 acre-ft.

$69{,}000 \times 43{,}580 = 3.015 \times 10^9$ cu. ft.

$\frac{3.015 \times 10^9}{5.76 \times 10^6} = 522.5$ hours for 1 unit.

$522.5 \times 30{,}000 = 15{,}650{,}000$ hw-hr.

As a check, it is interesting to note that the summation of the kw-hr. obtained by operating 6 units until limited by the Feeder Canal, then 4 units, then 2, and 1, gives a total of 86,700,000 kw-hr, which is exactly the figure obtained by operating 1 unit alone for the entire available drawdown.

C.

In a) and b) consider alternate uses of water in a yearly pumped storage schedule.

a) Base Load Operation

In years when the water is low for a period of many months, as happens cyclicly at approximately 4 year intervals, it might be more advantageous to operate 2 reversible units continuously for the possible drawdown, during the most critical period.

Assuming a load factor of 78%, and an output from 2 units of 60,000 kva, a reservoir drawdown from 1570 to 1558 ft. gives $\frac{1185 \text{ hr.}}{24 \text{ hr.} \times .78} =$ 63.2 days of operation.

b) Peak Load Operation

In more normal years, when the water shortage is purely seasonal, it will be more advantageous to operate the reversible units as a peak load plant. This would mean operating 6 units for peaking as long as the Feeder Canal would allow, then 4 units, and so forth.

If it should prove possible to start the reverse flow cycle with the Equalizing Reservoir full, 6 units could operate for a total period of 143 hrs., producing an output of 180,000 kva. Refer to the Load Duration Curve, which has been calculated and constructed from the load data and load curve from March, 1950, as a typical load curve for this low water period. These 6 units could carry $\frac{180,000 \text{ kw} \times 100}{3,226,000 \text{ kw maximum}} = 5.575\%$ of the total peak load as of a typical week in March, 1950. From the Load Duration Curve for this week, this upper 5.575% of the total load occurs for 30 hours per week. Thus, these 6 units could absorb 5.6% of peak load for $\frac{143 \text{ hr.}}{30 \text{ hr/week}} = 4.75$ weeks. The units would go on the line when the load reaches 94.4% of maximum.

Since these units would not be able to regulate, they would operate on base load during these periods.

The units would operate as indicated in the load curve shown on the following curve sheet. This is not a very good method of operation, but it is about the best that they can do, as they cannot regulate. This method does obviate the necessity of any other installed capacity to handle the peaks. Regulating units permit a more efficient use of the water, and a more elegant solution. Although these units do not regulate, a certain degree of regulation of a block nature could be obtained by cutting units in and out.

After 6 units can no longer be operated at full load, 4 units could be used producing 120,000 kva. These could operate at maximum load for 170.5 hr. These 4 units could furnish

$\frac{120{,}000 \text{ kw} \times 100}{3{,}226{,}000 \text{ kw maximum}} = 3.72\%$ of peak load as of a typical week in March 1950.

From the Load Duration Curve, the upper 3.72% of the load occurs for 18 hours per week. Thus, 4 units could absorb the upper 3.72% of the load curve for $\frac{170.5 \text{ hr.}}{18 \text{ hr/wk}} = 9.47$ weeks.

Operating 6 and then 4 units, peaking could be accomplished for:

a) 4.75 weeks at 5.6% maximum load

b) 9.47 weeks at 3.72% maximum load.

c) <u>Operation on a 24 hr pump and Return Schedule</u>

This type of operation practically assumes peak load operation of the plant. Therefore, the utilization of a 24 hr pump and return schedule follows very closely the preceding articles on peak load operation, for a yearly pumped storage plan. The number of units used and the length of time that they could be operated reversibly would be determined by the Equalizing Reservoir elevation, which would depend in turn upon the water and energy made available for pumping in the time interval between drawdowns.

Use of Specially Designed Pump- Turbine Units, with Wicket Gates to Provide Regulation.

A. Data on the number of reversible units which can be operated at different Equalizing Reservoir elevations is the same as noted in part A of the previous section.

B. Hours of operation possible for 6, 4, 2, and 1 units, as limited by the Feeder Canal at different reservoir elevations is the same as noted in part B of the previous section.

C. Optimum methods of operation to utilize available kw and kw-hr most effectively.

Data for A and B will be taken from the preceding section. Only C will be discussed in detail.

C.

Since wicket gate pump-turbine units can be regulated, the problem must be studied from a somewhat different approach than in the previous section. Instead of furnishing solid blocks of energy, these units could just take off the load peaks, utilizing the available peaking energy much more efficiently.

Let it be assumed that the reverse turbine efficiency = 88%. This is in line with the published data on the most recent tests on units of this type and of comparable size. The efficiency of the alternatormotor units now in use with the pumps is 97%. Although 2 speed units might be advisable for use with the pump-turbines for highest efficiency, this should not effect their electrical efficiency.

This gives an overall efficiency of 97% x 88% = 85.5%

6 units having 50,000 kva capacity would have an output of:

$$6 \times 50{,}000 \times 0.855 = 256{,}000 \text{ kva.}$$

The same water requirements per reversible unit will be assumed here as in the previous section. This is 1600 cfs at a head of 280 ft., as for pump operation. This means 143 hours of operation for 6 reversible units, causing a reservoir drawdown of 3.3 ft. from 1570 (or full) to 1566.7 ft.

This gives 143 hr x 256,000 = 36,600,000 kw-hr of energy at a capacity of 256,000 kva.

This represents $\frac{256{,}000 \times 100}{3{,}226{,}000 \text{ kw maximum}} = 7.93\%$ of the maximum total load for a typical week in March 1950.

A Peak Percentage Curve has been constructed from the Load Curve and Load Duration Curve data for a typical week in the month of March, 1950. This curve will be used in determining the most efficient use of the available energy for peak power.

If it is considered as a first assumption, that furnishing this percent of peak power for a period of 12 weeks, or 3 months would be advantageous, $\frac{36{,}600{,}000 \text{ kw-hr available}}{12 \text{ weeks}} = 3{,}050{,}000$ kw-hr per week would be available.

This represents $\frac{3{,}050{,}000 \text{ kw-hr per week for peaking}}{423{,}479{,}000 \text{ kw-hr total in 1 week}} = 0.72\%$ of total kw-hr.

Applying these data to the Peak Percentage Curve, the 7.93% figure is the vertical projection on the curve, and 0.72% is the horizontal projection. These two axes will not fit the curve at any point, as the curve is not steep enough. Thus, a shorter period than 12 weeks must be used. This time may be found by using the above method in reverse.

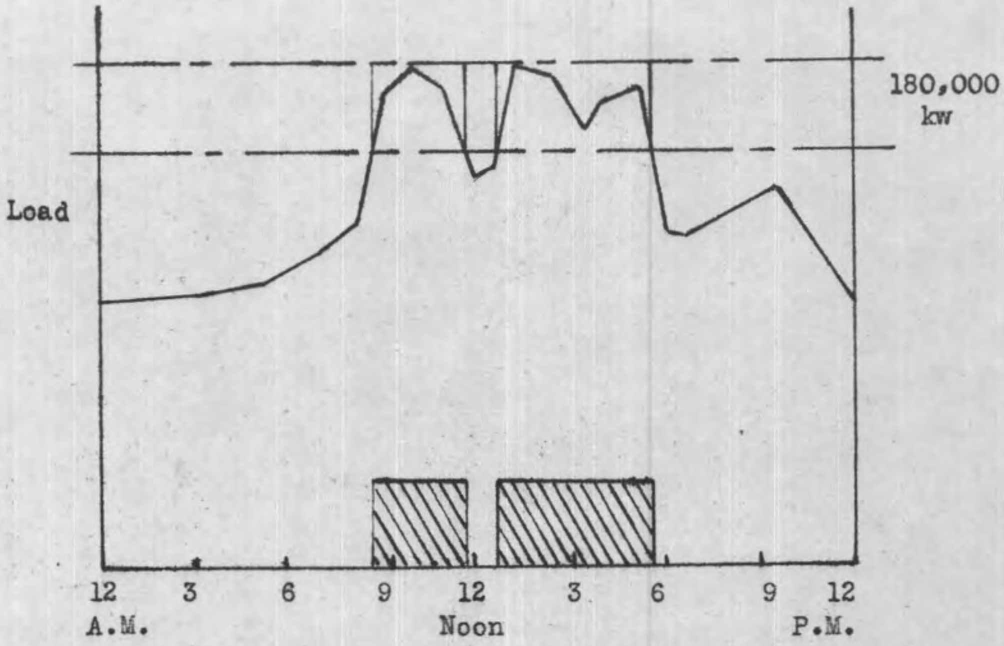
The vertical distance remains the same at 7.93%.

The Peak Percentage curve is steepest at the bottom, so measuring up from the origin, the curve gives a horizontal displacement of 1.1%. Thus, 1.1% of total kw-hr in peak x 100 x 423,479,000 total kw-hr in peak equals 4,658,000 kw-hr per week for peaking.

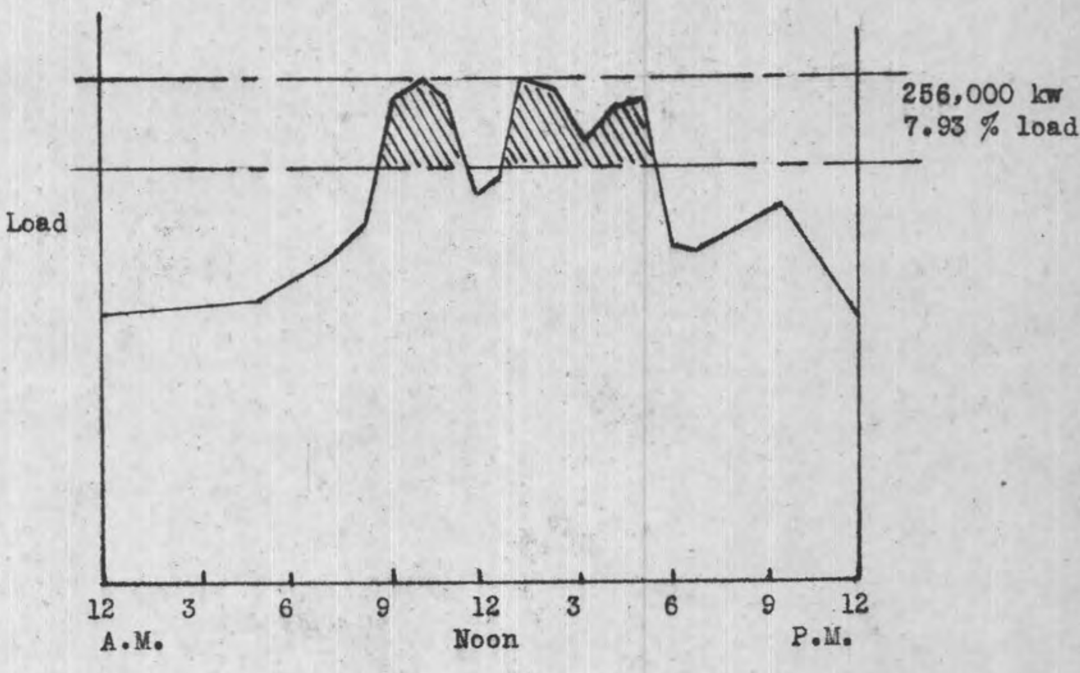
Now, $\frac{\text{36,600,000 total kw-hr available for peaking}}{\text{4,658,000 kw-hr per week for peaking}} = 7.85$ weeks

This means, that if the 6 units ran reversibly, being placed on the line whenever the load reached within 7.93% of the maximum or, in other words, reached 92.07% maximum, they could handle this percent of the peak load for a period of 7.85 weeks. They would produce as an average, 4,658,000 kw-hr per week, at a rating of 256,000 kva. This energy is 1.1% of the total kw-hr per week in the peak. These values just fit the bottom portion of the Peak Percentage Curve.

Only 6 units are considered here for reverse operation, with a drawdown from 1570 ft. maximum of 3.3 ft. The use of 4, 3, 2 and 1 units reversibly at lower reservoir elevations may be calculated in a manner similar to that above.



USE OF PRESENT PUMPING UNITS REVERSIBLY. ENERGY IN BLOCKS. ROUGH REGULATION COULD BE OBTAINED BY MANUALLY PUTTING UNITS ON AND OFF THE LINE.



USE OF SPECIAL WICKET-GATE PUMP-TURBINES. MORE EFFICIENT USE OF ENERGY AVAILABLE FOR PEAKING IS ACHIEVED BY REGULATING THE UNITS.

RESULTS AND CONCLUSIONS.

Calculated Load Factors for Typical Weeks for the Year 1950.

See Calculations.

March 1950: Load Factor = 78.1%

June 1950: Load Factor = 77.3%

Sept. 1950: Load Factor = 80.7%

Dec. 1950: Load Factor = 74.8%

Limitation of Feeder Canal. See Data

A) Limitation to Number of Pumps Which Can Operate at Different Equalizing Reservoir Elevations Without Backflow Over Siphon Crest.

10 pumps can operate up to a reservoir elevation of 1560.0 ft.

8 " " " " " " " " " 1565.5 ft.

6 " " " " " " " " " 1567.6 ft.

4 " " " " " " " " " 1569.0 ft.

2 " " " " " " " " " 1569.8 ft.

The above assumes a pump output of 1600 cfs. Reservoir full elevation is 1570 ft.

B) Limitation of Number of Reverse Pump-Turbine Units at Different Equalizing Reservoir Elevations by Backflow Limitations of the Feeder Canal.

6 turbines can be operated at maximum load from a reservoir elevation of 1570 ft (full) to 1566.7 ft.

4 turbines can be operated at maximum load from a reservoir elevation of 1570 to 1562.5 ft.

2 turbines can be operated at full load down to a reservoir elevation of 1558.0 ft.

Assume a water use per turbine of 1600 cfs at full load.

Estimated Irrigating Water Requirements from the Equalizing Reservoir. See Data

Monthly: The irrigating season will eventually begin in March and end in October. As might be expected, the irrigation water demands are relatively light in March and October, being much heavier during June, July, and August.

Yearly: The predicted irrigation water requirements for the year of 1961 is 2,468.9 (1000 x acre-ft)

The predicted ultimate minimum irrigation water requirement is 3,634.5 (1000 x acre-ft)

The predicted ultimate maximum irrigation water requirement is 4,320.9 (100 x acre-ft)

Primary Pumping Requirements in Power Demands and Water. See Data

A) Primary Pumping Power Demands:

1953 - 288,600,000 kw-hr

Ultimate - 1,565,400,000 kw-hr

B) Primary Pumping Requirements:

1952 - 1955 pump during May through July.

1956 - 1958 pump during May through August.

1959 - 1960 pump during April through August.

1961 - Ultimate pump during April through September.

The total predicted acre-ft required per year, of course, corresponds to the irrigation water requirements listed in the preceding article.

Pumping Requirements for:

1952 - 540,000 acre-ft.	1957 - 1,906,000 acre-ft.
1953 - 820,000 acre-ft.	1958 - 2,028,000 acre-ft.
1954 - 1,060,000 acre-ft.	1959 - 2,039,100 acre-ft.
1955 - 1,333,100 acre-ft.	1960 - 2,215,000 acre-ft.
1956 - 1,527,400 acre-ft.	1961 - 2,791,000 acre-ft.

Projected Equalizing Reservoir Elevation at End of Irrigating Seasons. See Data

The Equalizing Reservoir reaches its maximum elevation at the end of the pumping season, as would be expected. This will occur in August for the next few years, then occur in September after 1961. It is planned that the reservoir be completely filled for the first time in 1958. The fall drawdown leaves the reservoir near or below its minimum backflow elevation until the year 1961. In 1961 and later, due to a longer and later pumping season to meet expanding irrigation needs, pumping continues into September. This leaves the reservoir at an elevation of 1564 ft after fall irrigation is complete. This leaves a possible reverse flow drawdown of 1564 - 1558 = 6 ft. There is no predicted data on the reservoir elevation after the year 1961.

Present Pump Units Operation as Turbines. See Data

The present pump units should operate satisfactorily as turbines, furnishing block units of energy since they have no load control. A model of the pumps showed a turbine output of about 60% pump power input for the same speed and head. The efficiency should be approximately 2% lower for turbine action than for the pump action for which it was designed.

Manufacturer's Information on Reversible Pump-Turbine Units. See Data

Reversible pump-turbine units can be furnished with or without wicket gates to provide regulation. They could have about the same rating and efficiency in either direction - about 90% for pump action and 88% for turbine action. The wicket type is larger for a given speed and impeller diameter and hp rating. To meet the present hp rating and fit in the present pump pits, wicket gate units would need to have a smaller impeller diameter and higher specific speed and higher speed in rpm. This might introduce some problems involving the minimum allowable water level in Lake Roosevelt for pumping action and possibly some cavitation problems.

The cost of the reversible units would be somewhat higher than the cost for a straight pump. They would probably cost about $600,000 apiece, neglecting the initial design costs.

The Allis-Chalmers Co. and the Baldwin-Lima-Hamilton Corp. were contacted.

Possible Availability of Surplus Power for Pumping During the Winter from Run-of-the-River Plants. See Data

There is almost no surplus power during the winter months, with the present degree of Columbia River regulation. During low load periods, Grand Coulee and the other reservoir dams in the system store water, letting the run-of-the-river plants, such as Bonneville, carry the load to their ability.

Proposed Steam and Gas Turbine Plants for the Northwest, as Proposed by the Bonneville Power Administration, 1952. See Data

3 steam electric plants of 100,000 kw each are proposed.

5 gas turbine electric plants totaling 100,000 kw are proposed.

This gives a total of 400,000 kw of new steam and gas turbine capacity proposed. Unfortunately, it does not appear probable that this addition will be made immediately.

Cost of New Steam and New Hydro Plants. See Data

New steam plants cost about $170 per kw of capacity to construct, by recent estimates.

New hydroelectric installations costed an average of $258 per kw of capacity from a tabulation of new construction of the past year (1952).

Installed Steam Capacity in the Pacific Northwest. See Data and Calculations

There are 14 steam plants in operation in the Northwest Power Pool. Their combined capacity is:

Rated capacity	380,000 kw
Peak capacity	470,000 kw

The larger, more economical plants are all in the Seattle or Portland areas. These 4 more efficient plants make up approximately one-half of the total capacity of the combined steam capacity. The peak capacity of the 4 larger plants is 238 mw, with an average incremental cost of 6.4 mills per kw-hr. The costs for the other plants range up to a maximum of 15 mills per kw-hr.

The basic operation of the steam reserve varies from year to year. In normal water years, the 4 more efficient plants are kept in spinning reserve about 50% of the time. During low water years, which occur in approximately 4 year cycles, the steam plant operate on base load for the entire period of the water shortage.

These plants are at too great a distance from Grand Coulee to provide pumping energy directly for pumped storage, but indirectly by shuttling energy across the Power Pool, they could in effect furnish the required energy.

The high cost of steam energy tends to destroy the economic advantage which may be gained by pumped storage.

Optimum Methods of Operation to Utilize the Available Kw and Kw-hr Most Effectively as Produced by Pumped Storage. See Calculations

A) Using Present Type of Pump Units Reversibly

The rated output of the present pump units operating reversibly as turbines is reduced to approximately 60% of their pump rating. This would give output ratings at different Equalizing Reservoir elevations as shown in the following tabulations:

Number of Units	Maximum kva	Maximum drawdown From Full	Acre ft Available	Hours of Operation at Max. Rating	kw-hr
6 units	180,000	3.3 ft.	113,100	143	25,750,000
4 units	120,000	7.5 ft	203,100 from full	384	46,600,000
			90,000 from 1566.7 ft	170.5	20,400,000
2 units	60,000	12.0 ft	313,100 from full	1185	71,000,000
			110,000 from 1562.5 ft	416	25,000,000
1 unit	30,000	15.0 ft	382,100 from full	2890	86,700,000
			69,000 from 1558.0 ft	522.5	15,650,000

Since these units have no means of control, the energy would be released in blocks. This is shown very clearly in the following curve sheet.

First, consider 6 unit operation, starting with the reservoir full. The pumped storage plant should take load whenever the load reaches within 180,000 kw of the peak load of the period involved. For the period investigated, (March, 1950) this maximum output of 180,000 kva can absorb 5.6% of the peak load. By going to the Load Duration Curve for this period, it is found that the load exceeds 100 - 5.6 = 94.4% of the peak value for approximately 30 hours per week. The plant should then go on or off the line as the load exceeds or falls below this value. The pumped storage plant could operate in this way for a period of 4.75 weeks, absorbing all of the upper 5.6% of the load curve.

After this, only 4 units could operate at full load without further pumping. These 4 units could absorb 3.72% of the peak load (as of March, 1950) for a total period of 170.5 hours. From the Load Duration Curve, the load exceeds 100 - 3.72 = 96.2% of the peak load for approximately 18 hours per week. The plant should then go on the line when the load exceeds 96.2% of peak load and drop off when the load decreases below this value, and can operate thus for a period of 9.47 weeks following the 6 unit operation.

Peaking energy could be saved if the units were cut in and out manually as the load demands, giving a rough block step type of regulation. This is not shown on the curve sheet.

B) <u>Using Specially Designed Pump-Turbines with Wicket Gates</u>

The rating of specially designed pump-turbine units is much higher than it is for the present type of pump units used reversibly. Six of the pump-turbine units should have an output of approximately 256,000 kw at full load as compared to 180,000 kw for the pump units. The number of hours of operation and water use is assumed to be the same for the two types of units.

Since the pump-turbine units have wicket gates, they could be furnished with governor control and made to regulate over the peaks of the load curves. This type of operation gives a greater economy in water use with better utilization of the available peaking energy. As they will not necessarily operate at full load at all times as in the unregulated case, the hours of operation must be determined by the number of kw-hr in the peak.

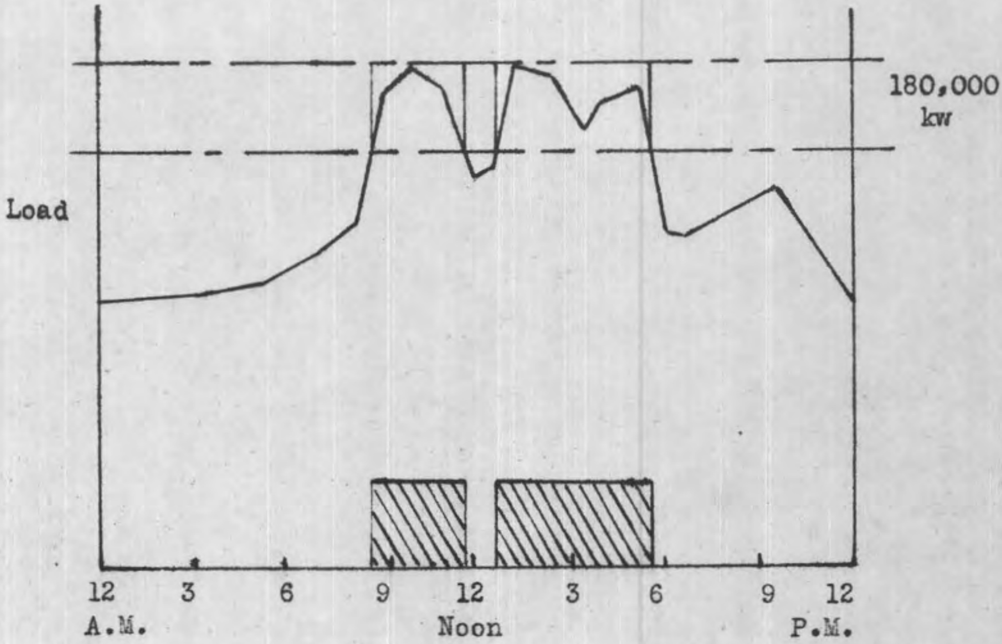
From the Load Duration Curve and the Peak Percentage Curve for a typical week in March, 1950, it was determined that for 6 unit operation with the Equalizing Reservoir full, the optimum operation would be as follows. The plant should be placed in service whenever the load reaches 92.07% of maximum, and taken out of service whenever the load drops below this value. The pumped-storage plant could handle this upper portion of the load curve for a period of 7.85 weeks. This is as compared to 4.75 weeks when the units are non-regulating. The above type of operation would furnish an average of 4,658,000 kw-hr per week at a maximum rating of 256,000 kva. furnishing 1.1% of the total kw-hr in the peak.

After the Equalizing Reservoir reaches a drawdown of 3.3 ft from full, 4 units could be operated at full load, the points of operation being calculated in the same way as the example above.

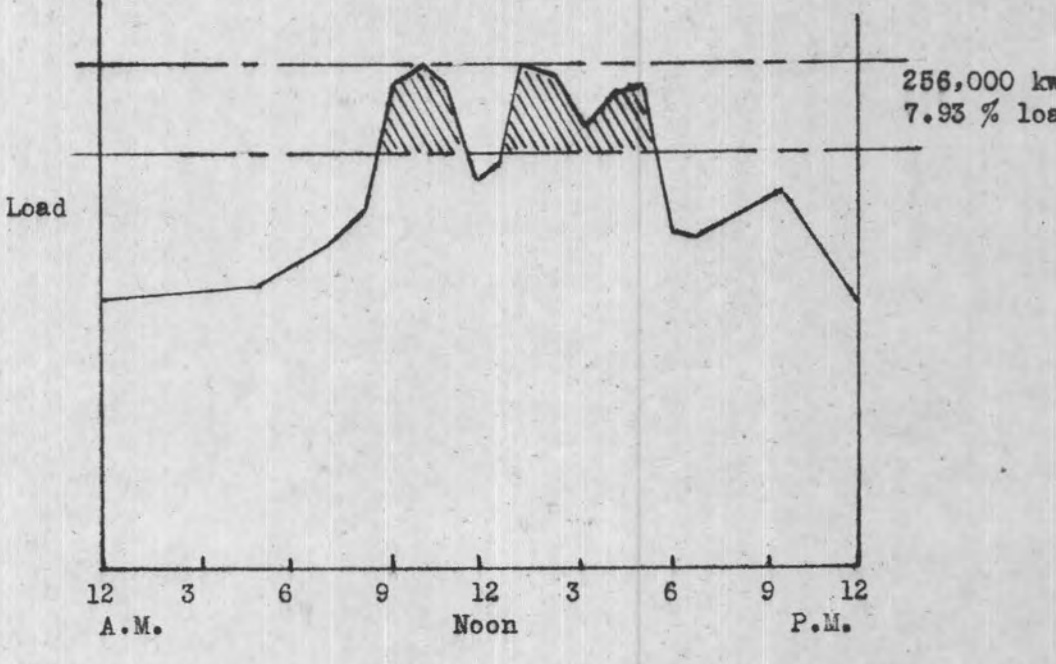
Curves showing both the regulating and non-regulating type of operation are shown, indicating the advantage gained by regulation.

Comparison of Water Use in Kw-hr per Gallon of Water Directly Through the Grand Coulee Main Turbines vs. Use by Pumped Storage. See Calculations

At rated load, one of the main Grand Coulee turbine-generators would produce 108,000 kilowatt-seconds. If this energy were used to pump water up into storage, then the water returned to Lake Roosevelt through the reversible pump turbines, the energy output would be 71,100 kilowatt-seconds.



USE OF PRESENT PUMPING UNITS REVERSIBLY. ENERGY IN BLOCKS. ROUGH REGULATION COULD BE OBTAINED BY MANUALLY PUTTING UNITS ON AND OFF THE LINE.



USE OF SPECIAL WICKET-GATE PUMP-TURBINES. MORE EFFICIENT USE OF ENERGY AVAILABLE FOR PEAKING IS ACHIEVED BY REGULATING THE UNITS.

This represents an overall efficiency of 66.6% for the entire cycle. In other words, we have the choice of taking the 108,000 kw-sec directly from the Grand Coulee unit, or using this energy for pumping, with a final energy release of only approximately 71,100 kw-sec. This occurs when non-surplus water is used to generate power for pumping into pumped storage. Thus, from a standpoint of kw-hr per gallon of water behind Grand Coulee Dam, or considering water efficiency, pumped storage is at a disadvantage in an all-hydro system.

When pumping can be done with off-peak steam energy, the above problem does not arise.

Pumping Time Required to Meet the Predicted Ultimate Irrigation Water Requirements. See Calculations

It has been calculated that it will take a pumping period of approximately 140 days to pump enough water to fill the predicted minimum ultimate irrigation water requirements. This makes a number of assumptions. It assumes an average pump output of 1450 cfs over the entire pumping period, neglects the limitations of the Feeder Canal, and assumes a pump outage of 10%. A final installation of 10 pumps is assumed. (This might be altered by the application of Alternative 2.)

The figure of 1450 cfs is considerable below the maximum output of 1600 cfs, but may be a reasonable assumption if the change in pumping head is considered and the limitation of the Feeder Canal at the upper elevations.

If the maximum output of 1600 cfs for the pumps is assumed, only 126 pumping days are needed to meet the ultimate requirements.

This output is only for the minimum pumping head of 280 ft, and is considered to be rather optimistic.

Pumping Time to Meet the Predicted Irrigational Water Requirements in the Year 1961. See Calculations

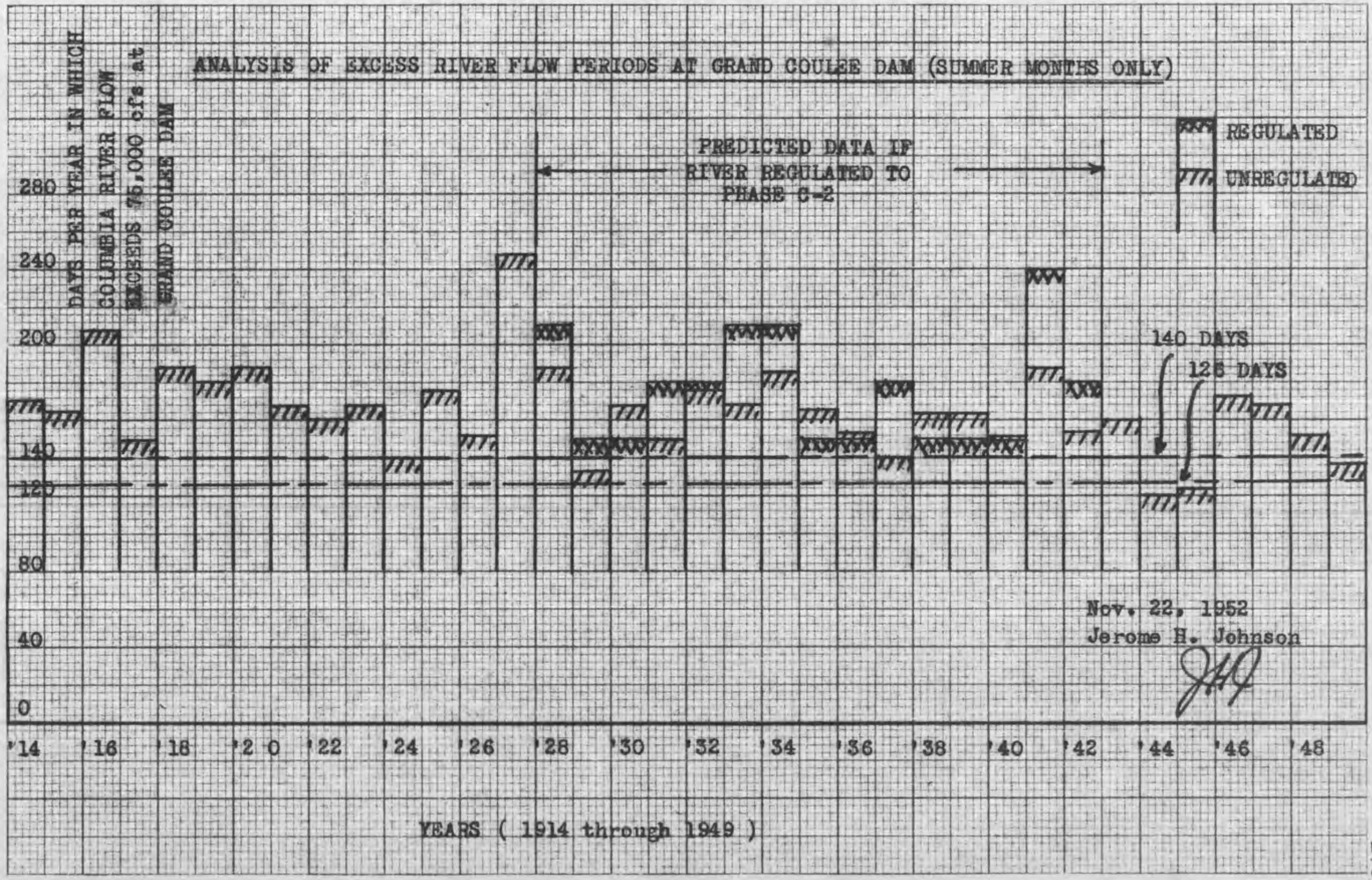
It has been calculated that it will take approximately 158 pumping days to meet the projected irrigation water requirements in the year 1961. A pump installation of 6 pumps is assumed, and an average pump output of 1450 cfs throughout the season is used.

Projected Effect of River Regulation by Upstream Dams on Surplus Water (Ideal Pumping) Periods. The effect of river regulation upon the surplus water period in the summer is not nearly as significant as its effect during the natural low water periods in the winter except as a factor in flood control. By river regulation, is meant the regulation of the Columbia River to the planned Phase C-2. This includes the upstream dams of Cabinet Gorge, Hungry Horse, and Albeni Dams, which are now under construction, and Libby Dam, which is authorized, plus Glacier View, which is included in the planned Phase C-2. These would give a total reservoir storage capacity of approximately 11,000,000 acre-ft.

The main effect of the upstream dams in the summer, is to clip off the top of the flow curve as the river crests in the early summer. From the standpoint of pumped-storage in its relation to the irrigation season and extra storage pumped for reverse flow, it could be desired that the surplus period be considerably lengthened to allow pumping after irrigation is complete - or at least until the end of the irrigating season. However, this is not possible.

The run-off is so tremendous when it occurs, the actual reservoir capacity so tiny in relation to it, and the run-off is of such abrupt and definite duration, the filling of the upstream reservoirs causes little change in the length of the run-off period. In the 15 year period in which predicted data are available for the Columbia River regulated to Phase C (which is very similar in effect to Phase C-2) the surplus period of water flow would have been increased by an average of 36 - 25 = 11 days. This is not a very significant addition to the ideal pumping period. However, it does help, as is shown by the fact that in the 1928-1942 period the Excess River Flow curve shows that the surplus period dropped to 140 days and below twice for the river unregulated. If the river had been regulated, the minimum pumping period of 140 days would have been exceeded by at least 10 days each year of the 15 year interval studied. All of the data for the regulated and unregulated Columbia River, is for its flow at Grand Coulee Dam.

For the 36 year period in which the actual river flow was studied (1914-1949), the period of surplus water flow at Grand Coulee (assuming an average powerhouse use of 75,000 cfs) dropped below the minimum pumping days necessary to meet the ultimate minimum irrigation water requirements of 140 days in only 6 years. This is 16.6% of the time. It is interesting to note that 3 of these years occurred in the last 6 years studied, which might possibly indicate a trend due to a weather cycle, de-forestation, or some other unknown factors.


ANALYSIS OF EXCESS RIVER FLOW PERIODS AT GRAND COULEE DAM (SUMMER MONTHS ONLY)
DAYS PER YEAR IN WHICH COLUMBIA RIVER FLOW EXCEEDS 75,000 cfs at GRAND COULEE DAM
PREDICTED DATA IF RIVER REGULATED TO PHASE C-2
REGULATED
UNREGULATED
140 DAYS
126 DAYS
280
240
200
140
120
80
40
0
'14
'16
'18
'20
'22
'24
'26
'28
'30
'32
'34
'36
'38
'40
'42
'44
'46
'48
YEARS (1914 through 1949)
Nov. 22, 1952
Jerome H. Johnson
JHJ

The Average Period of Excess River Flow Beyond that Required to Meet Predicted Ultimate Irrigation Water Requirements. See Calculations

As noted previously, the minimum pumping time will ultimately be 140 days. Considering only the summer excess flow periods, it has been calculated that the period of excess flow exceeds this 140 day minimum for:

25.3 days per year for the River unregulated,

36.0 days per year for the River regulated to Phase C in a fictitious "average" year.

In 25.3 days, an installation of 10 pumps could pump into storage a total of 654,000 acre ft.

In 36 days, an installation of 10 pumps could pump into storage in the Equalizing Reservoir a total of 932,000 acre-ft.

This is to be compared to the total usable storage of 382,000 acre-ft available for reverse flow in the pumped storage operation, as limited by the reverse flow characteristics of the Feeder Canal.

These figures must be examined with considerable caution. First, in the years when pumped-storage would be needed the most, the exceptions to the "average" could occur, greatly decreasing the utility of the project. There is no indication that this is the case, however, or that any such correlation exists. Second, the irrigation season lasts for a longer period than the excess water period and thus the ideal pumping period when additional storage to the system could be accomplished. The irrigation season lasts for

8 months, from March through October. The pumping season lasts as an average for something over 140 + 25 = 165 days or approximately $5\frac{1}{2}$ months. Since the Equalizing Reservoir must supply irrigation water during the periods before and after the pumping season, and since the reservoir has a rather limited capacity, the effect of these extra pumping days is largely cancelled out. As shown on the predicted Equalizing Reservoir Operating Curve, the reservoir is completely filled each year at the end of the ideal pumping season or season of surplus water. However, it is also shown, that the fall irrigation draws the reservoir down to a point where no reverse flow is possible. The predicted data is only shown through the year 1961, but it is difficult to see how this factor will change for the better.

It is of considerable interest to this study that with the Phase C River regulation, there are often periods during the late fall and winter when the river flow exceeds the average Grand Coulee powerhouse use of 75,000 cfs, with the flow rarely dropping below 50,000 cfs. Thus, there might well be periods of excess flow after fall irrigation is complete and the Equalizing Reservoir might be filled to its upper elevations making reverse flow operation possible. For the Phase C River regulation, 7 out of the 15 years studied had periods of 1 to 4 months in the winter when excess flow was predicted.

Effect of the Projected Third Powerhouse at Grand Coulee Dam on River Flow. See Calculations

In this analysis of the effect of the installation of a third powerhouse at Grand Coulee, an addition of 9 units of the same capacity as those already in use is assumed. The present maximum water use for the 18 installed turbines at Grand Coulee is 90,000 cfs, with an average water use of approximately 75,000 cfs. The addition of 9 more units would raise this to a maximum use of 135,000 cfs, or an average use of approximately 110,000 cfs.

In the period between 1914 and 1949, only 4 out of the 36 years studied equalled or exceeded the minimum number of days of excess water necessary for ideal pumping (140 days) to meet the ultimate minimum predicted irrigation water requirements, with the 10 final pumping units installed as presently planned. This is for the river unregulated, and assuming an average powerhouse use of 110,000 cfs.

Considering the completion of the Phase C-2 of Columbia River development, in the period 1927-1942 in which predicted data is available, only 1 year reaches the minimum number of pumping days to meet the ultimate irrigation requirements, by surpassing 110,000 cfs for 140 days.

Thus, if a third powerhouse at Grand Coulee should be installed, this additional capacity could only be utilized during the summer run-off period, and then only on a priority basis for most of the time, due to its overlapping with the pumping time necessary to meet irrigation water needs.

<u>Projected Effect of River Regulation by Upstream Dams on Low Water Periods</u>.

1. By storing the summer run-off of the ice fields, the upstream dams tend to even out the flow of the Columbia at Grand Coulee. In the natural low-flow periods during the coldest part

of the winter (Jan., Feb., March) the upstream storage is released as needed. This will greatly reduce the severity of the recurring seasonal power shortageswhich now plague the Northwest. The released water has two effects at Coulee--giving more water for utilizing more nearly full generating capacity, and second, in holding the level in Lake Roosevelt, thus maintaining the head at the Grand Coulee turbines. As an illustration of how effective this may be, the curves (Data) are analyzed from the Army 308 Report for predicted calculated effects of upstream storage (C-2 phase including Hungry Horse, Libby, and Albeni Dams, plus Glacier View which is desirable and probable.) In the 15 year period studied (1928-1942), 13 of the years dropped below a minimum of 50,000 cfs. If the river had been regulated, not one year would have dropped below a flow of 50,000 cfs.

In this 15 year period, the average regulated flow through the low-water months of Oct., Nov., Dec., Jan., Feb., and March is between 60,000 and 70,000 cfs. This is very significant when we realize that average powerhouse water use at Coulee is approximately 75,000 cfs. The total installed capacity on the Columbia is high, and will be much greater soon, with dams being completed as noted in the Data. With the increased flow through this tremendous installed capacity, the winter power shortage will be greatly alleviated.

This points up the fact that the need for a winter peaking plant will soon be less.

2. It must also be noted that by regulation of the river, it

would be possible during many years to obtain periods of flow above 75,000 cfs during the usually low water months.

In the 1928-1942 15 year period, the unregulated river actually surpassed 75,000 cfs twice during the winter--in the 1933-1934 winter and in 1941. Had the river been regulated, this would have happened 6 years, for periods of one month or more.

This allows refilling of Lake Roosevelt, or possibly extra water available for pumped storage. Thus, it appears that in later years with more complete river regulation by the completion of upstream dams we have a paradox. Pumped storage becomes more possible, due to longer periods of surplus water flow in the summer, but becomes at the same time less necessary as a result of elimination of seasonal low river flow periods.

Possible Alternative Methods of Constructing Pumped Storage Plants at Grand Coulee.

Alternative 1

Consider using the present installed 6 pump units reversibly as pumps or turbines, drawing the water out of Lake Roosevelt and pumping into the Feeder Canal on into the Equalizing Reservoir, or in reverse order for turbine and generator operation. Although no actual test data on reverse operation of the units has yet been taken, the pump designers indicate that there is no reason why they should not operate satisfactorily as turbines--having, however, only about 60% of their pump hp rating. The efficiency should be only about 2%± different for turbine action. The only additional electrical equipment required would be transformers and circuit breakers plus a minor amount of control panel equipment. Of course, the present penstocks would be satisfactory. The major construction necessary would be modification of the Feeder Canal headworks and insertion of a by-pass for the canal input-output siphon. Also butterfly valves in the penstocks would be required.

Financially, this alternative is much the most conservative, and from an engineering standpoint, may be the soundest, until data on the unknown factors in the problem is obtained. These unknowns include: 1) the occurrence or extent of leakage of the Equalizing Reservoir at the upper elevations and the possibility and economics involved in repairing this leakage, should it occur. No method of reverse flow can operate with serious reservoir leakage, without very expensive canal or penstock modifications. 2) If the present pump units should not operate satisfactorily as turbines due to cavitation, very low efficiency or severe limitation of reverse flow rating, this alternative, at least, would need to be dropped. 3) The construction of modern steam plants (to be used for off-peak pumping) would modify the use of any such storage plant. 4) The extent and success of river regulation by the proposed and authorized upstream dams will influence the surplus water periods, making pumping for storage from surplus water more possible; and conversely, pumped storage peaking capacity less necessary. Since the reversed pump units are unregulated, all energy generated would be of a block nature, and so could not follow the actual peaks of power. They would furnish blocks of energy on base load during periods of peak power.

All of these limiting factors with the exception of No. 2 will be important in all of the following alternatives. No. 1, concerning the reservoir leakage, could block any further consideration of the problem by requiring modifications of prohibitive cost.

Alternative 2

Consider the installation of specially designed reversible pump-turbine units of the wicket-gate type in the 6 remaining pits in the pumping station. These would be of similar rating, but of different impeller diameter and speed than the present pump units. Since only 6 units can operate reversibly due to flow limitation of the Feeder Canal, the remaining number of units to be installed is very conveniently correct.

This may either be considered as a separate alternative, or as a logical extension of alternative 1, after at least one or two of the original pump units operate successfully in reverse, but at lower rating and efficiency.

The advantages of this alternative are: (1) Increased turbine efficiency and output rating. This could mean a saving of water in the reverse flow process. Of equal importance is the increase in available peaking capacity of the plant due to the approximately 20% increase in (from 60% to 88%±) rating in the pump turbines. (2) Since a specially designed unit would probably be of the wicket-gate type, they would regulate, and be able to follow the peak load while in use. This would permit the most efficient use of pumped storage water for peak power. The units would be furnishing only peak power instead of block energy on base load during peak power periods as in Alternative 1. (3) No alterations would be required on the presently installed pumping installation, except in the headworks. (4) No additional penstocks or pumping plant construction would be required. Only modification of the penstocks involved, to bypass the siphons. (5) The cost per kw of installed capacity is very low for this plan, when only the additional equipment and construction is considered as compared to the present plan. It would require the installation of the remaining 6 units in the near future, instead of at a later undetermined date. However, this should have no predictable effect on the final cost.

The disadvantages of this alternative are: (1) It requires the installation of 2 more units than the presently planned 10 units for the pumping plant. This could be overcome by modifying 2 of the present pump units, but the gain in this would be doubtful. Actually, 2 additional units available for pump duty could be advantageous. (2) The reversible units cost 20 to 30% more than the straight pumps. For reverse action, this cost is easily justified by increased efficiency and capacity. (3) For maximum efficiency in both directions of operation, a two speed motor-generator unit might be advisable. The cost of these should be somewhat greater. (4) The pumping efficiency of the reversible units is somewhat (2% or 3%) lower than for straight pumps. In a consideration of the pumping action of the reversible units, it has been noted that due to space limitations the impeller diameter would need to be smaller and specific speed greater. This could limit their pumping ability at low intake water elevation in Roosevelt Lake. This would not be much of a problem, however, as all pumping for irrigation occurs at times of surplus water when Roosevelt is full. At other times, the pumping would be relatively minor, and just the 6 conventional pumps should provide sufficient capacity.

Alternative 3

Consider using a complete separate installation of turbines and generators. This would have as its advantage the increased efficiency of both the pumps and turbines designed for one use only. A conventional Francis turbine of this size should have an efficiency of around 90% to 93% and the efficiency of a conventional pump of a similar rating should be in the same range. This is compared to an efficiency of about 90% for turbine action and 86% for pump action for the reversible dual purpose pump-turbine units, from Allis Chalmers data.

The disadvantage of this alternative is the greatly increased cost. The ultimate irrigation requirements will require an installation of at least 10 pumps. This leaves 2 of the original 12 pump wells and penstocks empty. However, to utilize the maximum reverse flow characteristic of the Feeder Canal 6 turbines and generators of the present water capacity and rating should be installed. This means that 4 additional units of the same rating or a smaller number of larger units with their penstocks and required powerhouse would be necessary, besides the 2 which could be put in the present pumping station.

This construction would be very costly, as compared with Alternatives 1 and 2, and the slight gain in efficiency by this alternative is too small to justify the added cost. This is very true when the low load and capacity factors of the plant is considered.

Alternative 4

Consider pumping water into the Equalizing Reservoir, using present pumps, and returning the water from the Feeder Canal through special penstocks and turbines with their generators into the pool at the base of Coulee Dam.

One advantage of this sytem over using reversible pump-turbine units, would be that the turbines and pumps designed for a single use would have a small advantage (about 2%) in efficiency. Also the units for return flow could be larger, using only 2 or 3 units, thus having a somewhat higher efficiency. No advantage would be gained in overcoming the Feeder Canal limitations.

Another advantage would be in a greater installed capacity and thus a greater peaking capacity, made possible by the greater head. Of course, the total energy obtained from the water in passing from the Equalizing Reservoir to the bottom of Coulee would be very nearly the same, as in the two steps through the pumping station turbines and then through the Coulee turbines.

The obvious disadvantage of this arrangement is the higher initial cost, due to the added construction involved. The construction of new penstocks, new generating station, installation of new turbines and generators, none of which would be necessary in using the present pumping station reversibly, would raise the initial cost per kw to several times that of any alternative plan utilizing the present pumping plant. However, the cost of straight pumps and turbines would be slightly less per kw, than for reversible units.

Considering the low capacity factor of any peaking plant such as this, and the small gain in efficiency produced by this more expensive alternative, the scheme is not justified economically by the improved efficiency.

In evaluating the advantage gained by the added installed capacity of this plan, due to the increased head, it must be noted that the periods during which the installation would be used would be during low river flow periods. During these periods, the Coulee main turbines would not be loaded to their fullest capacity. Thus, the system would not be suffering at these times from lack of installed capacity, but lack of water and storage. Running the water through the two steps--reversibly through the pumping plant and simultaneously through the Coulee turbines--would produce very nearly the same amount of peaking capacity and peaking energy as a single step plant under consideration.

The somewhat lower efficiency and greater losses of the first step (or the reverse flow through the pumping plant) of the two step alternatives 1 or 2, would be the only possible cause for reduction in capacity for this method and this would be at least partially compensated for by the higher efficiency of the larger main Coulee turbines involved.

<u>Modifications Necessary or Advantageous in Converting the Present Pumping Plant at Grand Coulee Dam to Alternatives 1 or 2 for Pumped Storage Operation.</u>

1. <u>Reservoir</u>: None required. If a fault should prove to exist in the reservoir causing serious leakage at the upper water

elevations, it would be advisable to correct the condition if at all possible. This would be advantageous for any use of the reservoir. If it should prove impossible or impractical to stop the leakage, the projected Bureau operating curves for the reservoir would need to be altered to fit the limiting conditions. For ideal 6 unit peak-load operation of the reverse flow plant, with the Feeder Canal unmodified, the reservoir must operate from 1570-1566.7 ft. or full.

2. Feeder Canal: The Feeder Canal can operate satisfactorily as it is, but with its present capacity it seriously limits the range and magnitude of operation of any pumped storage developed. First, it might be well to realize that the present Feeder Canal is designed very conservatively even for pumping operation, for which it was intended. The ultimate pump installation is for 10 units. If pumping is done with Lake Roosevelt high--as it will surely be during pumping period, which will coincide with summer surplus water periods--each pump has a capacity of 1600 cfs. Referring to the Feeder Canal, Forward Flow Curve, the Canal cannot satisfactorily carry the output of 10 pumps after the Reservoir elevation reaches 1560 ft, or 10 feet from maximum. The presently to be installed 6 units can only operate to an elevation of 1567.5 ft, and 4 units up to 1 ft of the maximum elevation. This only indicates that the Feeder Canal definitely limits the pumping operation. The Reservoir Operation Curve shows that it is planned to completely fill the reservoir each fall, so this problem will re-occur.

For reverse flow operation of the Canal, the limitation is even more serious. Six reversible units can be operated only from the full point for the Reservoir (1570 ft) to 1567.7, and 4 units at full load to 7.5 ft of drawdown to 1562.5 ft elevation.

This, reverse-flow operation is limited by 2 obstacles. First, can the Equalify Reservoir be operated at maximum elevation without serious leakage. Second, with pumping restricted at these higher levels by the Canal, it is doubtful that there would be time during surplus flow, even if there were sufficient water to fill the Reservoir to the necessary level.

Both of these limitations for reverse flow would be eliminated by a Feeder Canal modification. It could also remove all pumping limitations.

A much wider canal, or a completely new tunnel penstock directly from the pump station to the bottom of the Reservoir are two possible solutions. Either of these would be very costly, and doubtful of justification, considering the utility of the pumped-storage project. However, it must be considered for maximum utilization and flexibility of this project.

3. Head Works: At the upper end of the Feeder Canal, modification must be made for reverse flow. (If a tunnel were constructed, as mentioned in (2) these would be different.)

a. A by-pass would need to be provided for the siphons for maximum efficiency. Free fall has been considered in all reverse flow studies. This by-pass would only be used for reverse flow.

b. Head-works would need to be modified to withstand surges, which might occur during starting or stopping of units.

c. Provision for de-icing, since reverse operation would occur in the coldest part of the winter.

4. Penstocks: The present penstocks leading from the pumping plant to the Feeder Canal should operate satisfactorily for flow in either direction. There is a possibility that cavitation might occur during reverse flow, but in the present study with the data available it is not considered wise to speculate on every possibility.

In (2) a new penstock was considered to replace the Feeder Canal. This would completely by-pass the present system of penstocks.

5. Valves: At present the only valves in the pumping plant are the roller-gate valves at the Roosevelt Lake Inlet, in the Pumping Station. This type of valve gives no degree of control.

a. If the presently installed units are to be used reversibly, some method of regulating and cutting off the reverse flow must be provided. It would be unwise to attempt to really regulate these units as it is possible with the wicket gates, but a rough control would be advisable. A Johnson valve or butterfly valve just above the pumps would operate satisfactorily. Possibly a roller gate valve at the upper end of the penstocks would be sufficient. It is not necessary to be able to control the water flow to synchronize the generator units. It will be simpler to start and run them as synchronous motors with rotation reversed and then open the valves.

b. If specially designed reversible units with wicket gates are considered, no additional valves are needed. It is necessary to be able to un-water penstocks to work on them, but the siphon and by-pass arrangement at the upper end will serve to accomplish this.

6. Outlets into Lake Roosevelt: These should require no modification whatsoever. Some turbulence might occur in this underwater discharge, but would not be serious, especially considering the small number of hours of operation.

7. Turbines: As noted, the presently installed pumps can be used reversibly as turbines. However, their rating may be reduced to approximately 60% of their pump hp input at the same head. Also, head fluctuation will have a great effect on efficiency and output. If it were possible to change the speed from pump to turbine operation, these effects could be largely overcome, but this is not practical under the present circumstances.

As there are at least 4 more units to be later installed to meet the ultimate pumping requirements, it is possible to consider installing specially designed reversible units for these. This brings up several problems.

a. Reversible units usually are of the regulating type with wicket gates. The wicket gates also help compensate for head fluctuations. However, for a given hp and speed, a wicket gate unit is larger in diameter, and the pump wells are already poured. Any enlargement is limited by the units being adjacent to each other - and moreover, a major modification of the pumping station structure would be very costly and highly improbable. It can be assumed that any new pump-turbine units which would be installed would have about the same outer dimension as the present units. This would require a smaller diameter impeller, with a corresponding increase in specific speed to deliver the same quantity of water at the same hp. This would require a lower setting with respect to the suction water level of Lake Roosevelt, or Roosevelt would have to be held to a higher elevation than the minimum of 1208 ft during pumping to avoid cavitation. This would naturally be the case in any normal pumping period, as pumping is always done at high water, although it might be done at other times under a 24 hour pumped storage schedule. Any pumping at low elevation of Lake Roosevelt could be done using the presently installed pumps, if found to be advantageous.

b. Although the present pump units would offer un-regulated output in blocks, the wicket gate units could be regulated, and thus operate to use the available stored water and peaking energy most efficiently. To regulate, the units would need governors, and the required control equipment.

c. In some reversible units, a considerable increase in efficiency is affected by using two different speeds for pump and motor action.

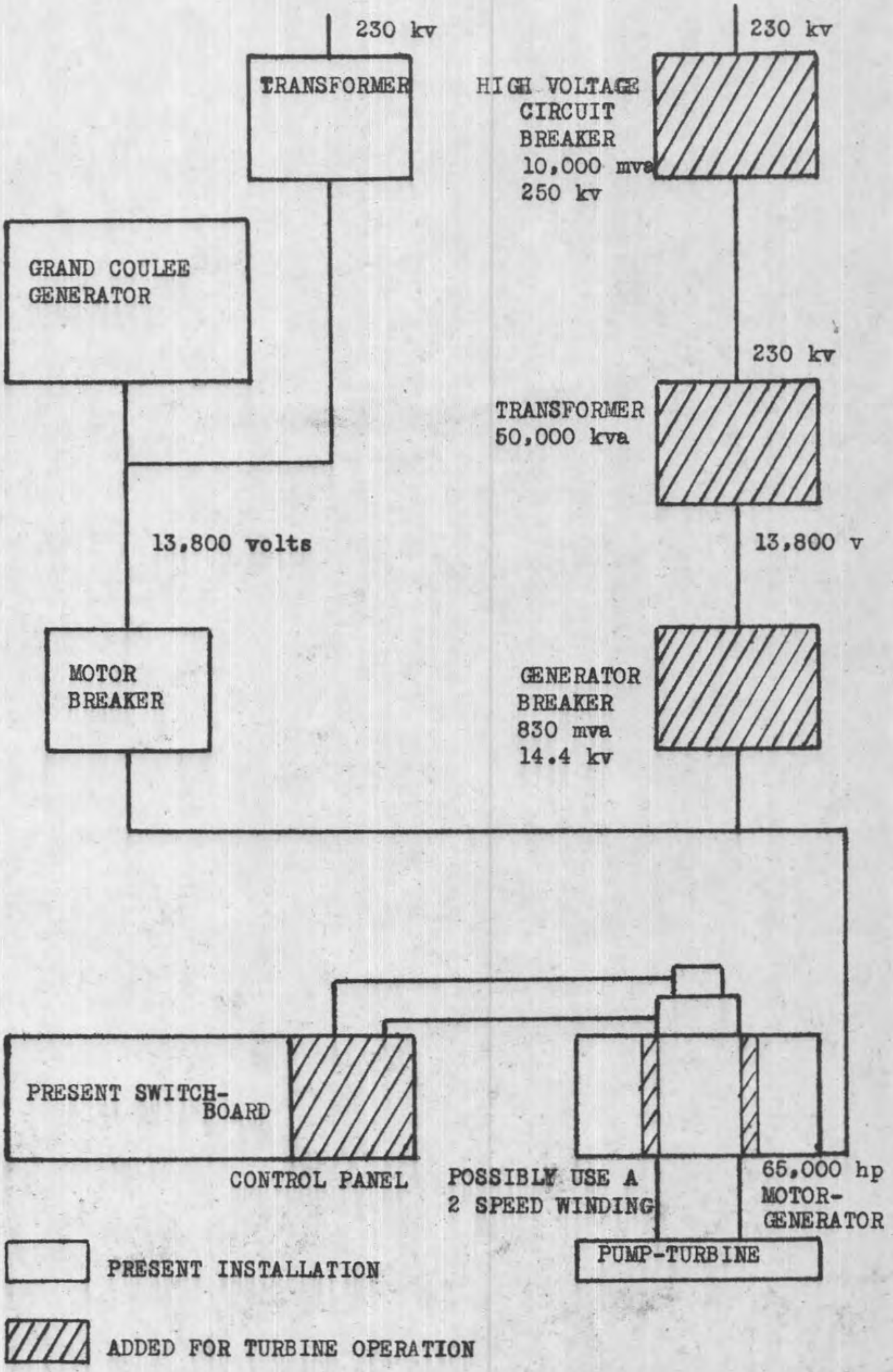
8. Dynamos: The units now installed should operate very satisfactorily for either motor or generator action. The bearings are designed for rotation in either direction.

If wicket type turbines having a higher specific speed should be used, electrical machines having a smaller number of poles would be required. The exact design would need to be worked out in conjunction with the turbine design. As indicated in 7, for a given reversible pump-turbine design, it may be advantageous to use two-speed electrical motor-generators for increased hydraulic efficiency. It would not be practical to change the present motor units for alternative number 1. Although a considerable gain in efficiency can be obtained by using two different speeds, one for motor and a lower speed for generator action, the cost of a two-speed machine makes this modification rather questionable, even in the case of alternative number 2. A two-speed machine is more expensive than two complete motors of similar rating.

9. Pumping Plant Structure: Some discussion of this has already been taken up in (7). It should be possible to use the present pump pits if the limitations are considered in designing new wicket gate type turbines. Any enlargement of these pits is considered impractical.

As pointed out in the next paragraph, considerable addition in the way of electrical equipment (reversing switcher, transformers, boards) must be housed or installed in or near this plant. The interior of the structure could house the reversing switches and boards without seriously over-crowding the area. Transformers would need to be placed outside--conceivably on top of the structure.

10. Transformers, circuit Breakers, and Control Equipment: The additional electrical equipment required for generator action of



ADDITIONAL ELECTRICAL EQUIPMENT REQUIRED TO CONVERT PRESENT PUMPING PLANT TO REVERSIBLE PUMP TURBINE OPERATION.

the electrical unit is shown in the diagram. The location and required rating of the equipment is also indicated.

11. Transmission Lines: The present lines should be adequate for peak operation as the reversible plant will be operating during periods of low river flow when the output of the main Grand Coulee generators are curtailed.

Preliminary Cost Estimate for Modification of the Grand Coulee Pumping Plant for Use as a Reverse Flow Pumped-Storage Plant.

Alternative 1

This alteration assumes modification of the pumping plant, using the present type of pump units. The plant would have a maximum generating capacity of approximately 180,000 kva, when modified in this manner.

The estimated cost per kilowatt of installed capacity is: $27.20 per kw.

Alternative 2

This alternative assumes the installation of 6 new specially designed reversible pump-turbines. This estimated cost includes only the differential in cost between the planned 10 pump installation and the modified plant as described in the preceding sections. Modified in this way, the pumped storage plant should have a maximum capacity of approximately 256,000 kva.

The estimated cost per kilowatt of installed capacity is: $30.90 per kw.

The above figures are of interest when compared with the cost per kw for new steam and new hydroelectric plants. Of course, these costs vary widely due to efficiency, design, and location. A figure which might be considered as a conservative average for steam plant construction in recent years is \$170 per kw. The average cost for non-Federal hydroelectric installations in the year of 1952 is \$258 per kw.

These costs must also be compared with those of the present steam plants already in operation in the area, as presented in the following section.

It must be noted that a considerable fraction of the already low cost per kw figures in Alternatives 1 and 2 is made up of electrical equipment such as transformers and switch gear which should probably not be charged against the cost of the power plant itself. These figures represent the entire installation.

Maximum Cost per Kw for New Pumped Storage Plant and Maximum Prices Which Can be Paid for Pumping Energy When Compared with Present Steam Plants. From a cost study of the present steam plants in the Northwest Power Pool, the operating costs, taxes and insurance, and maintenance have been considered in determining the cost per kw and the price per kw-hr paid for pumping energy of an alternate pumped storage development which could produce the same amount of energy at a total cost equal to the cost at the old steam plant, exclusive of the return on the investment. Since there is a very wide divergence in the costs of the different plants, 3 separate plants were investigated as representing the highest, intermediate, and lowest cost ranges involved.

Station	Maximum Permissible Cost of Pumped Storage Plant	Maximum Price Paid for pumping energy
Station H, Salem, Ore. 2000 kw	\$265 per kw	9.425 mills per kw-hr
Tacoma #1 8000 kw	\$175 per kw	6.54 mills per kw-hr
Shuffleton Plant, Renton, Wash. 75,000 kw	\$ 95 per kw	3.77 mills per kw-hr

When these figures are compared with the estimated costs of modification of the present pumping plant at Grand Coulee for pumped storage, the economic implications are very clear, as far as plant cost is concerned. For Alternative 1, or modification of the pumping plant using the present type of pump units, and for Alternative 2, assuming installation of 6 special pump-turbine units having wicket gates, the cost of modification is approximately \$30 per kw. The cost per kw is very nearly the same in either case due to the greater output of the special reversible units.

Prime power at Grand Coulee is valued at about 2.4 mills per kw-hr, and secondary energy is valued at only about 0.5 mills per kw-hr. The average value of secondary energy is between 2 and 0.5 mills, with the minimum rate used for irrigation water pumping.

Thus, a pumped storage plant of either type could be constructed and operated at the pumping plant at Grand Coulee at a capital cost and operating cost below the present steam plants. The fact that a pumped storage plant might not be able tooperate for the same number of hours per year as a comparable steam plant could modify the results. This could be caused by a number of factors such as the most efficient use of the available water supply, availability of power for pumping, usable reservoir capacity for reverse flow, irrigation water needs, Feeder Canal limitations in either direction, and others.

Evaluation of Yearly Pumped Storage.

1. The Columbia River flow exceeds the minimum required pumping days needed to meet the ultimate predicted irrigation water requirements (140 days) in 84% of the years, considering the 1914-1949 period during which the river was practically unregulated. This is assuming an average powerhouse use at Grand Coulee of 75,000 cfs.

In the 15 year period between 1928 and 1942 in which calculated curves are available showing what the river flow at Grand Coulee would have been if the Columbia had been regulated by the upstream dams of Hungry Horse, and Albeni, which are now under construction, plus the hoped for reservoirs at Libby and Glacier View, the results are even better. For the river regulated, the surplus flow period exceeded the minimum of 140 days in every case, although the period is too short to be conclusive. It is interesting to note, however, that the margin is rather slim, as 7 out of the 15 years studied are at or below 150 days of surplus flow. This is a rather narrow margin, considering that pumping limitations imposed by the Feeder Canal were not included in arriving at the 140 day figure. As a further comparison, in the same 15 year period as above, the unregulated river dropped below the 140 day min. in 2 years.

Thus, the question arises:

a) Is there sufficient time during the surplus water periods to pump both the required irrigation water and sufficient additional water for pumped storage to make a significant energy addition?

b) Will these years when it is not possible to pump extra water for pumped storage coincide with years having low winter river flow - when release of pumped storage water would have its greatest value?

Question a) must be answered in greater detail in the following paragraphs. In regard to b), from examining the river flow curves, no definite relation can be established between the length of the summer surplus flow and the river volume during the following winter. In fact, logically, no such relation should exist. It is interesting to note, however, that in more than half of the years having a small summer run-off, the winter preceding records a lower than average river flow. This is as should be expected, but depends to some extent on the reason for low winter flow, which may be caused by either small precipitation or a near complete freezing of the water supply by a very cold winter.

2. In a further consideration of the limitation imposed by the pumping time and the length of the surplus flow period, the limitation of Equalizing Reservoir elevation must not be neglected. Although, the projected schedule for reservoir operation calls for completely filling the reservoir each fall by the end of the ideal pumping season during surplus water, the irrigation requirements go on into late September and October, drawing the reservoir down an unpredicted but not negligible amount, depending on the natural precipitation, crops involved, and so forth. This is very serious, in any consideration of use of the Equalizing Reservoir for pumped storage.

Only the upper 3.3 feet of reservoir drawdown will allow use of 6 units reversibly, due to reverse flow limitations of the Feeder Canal. These 6 units would give an output of approximately 180,000 kva, assuming an output of only 60% of rated for reverse operation of the present pump units. This output would be available for 143 hours. This is a significant addition to the Power Pool's energy, and its most effective use is discussed elsewhere. The unfortunate fact remains, however, that this upper 3.3 feet of reservoir elevation will not be available in most winters, and any pumping to fill the reservoir to the full point would have to be done during times other than the ideal, or from water stored in Lake Roosevelt and with power which is certainly not dump power, using water to generate it which could be stored behind Coulee. This is very doubtful economy to say the least.

In years when the surplus water period is very long in the fall, allowing continued pumping and ending of the irrigation season with a full reservoir, this might be changed. However, in these years, the need for pumped storage would probably be at a minimum.

3. As stated, it appears that there should be enough time during a large percentage of the years to pump sufficient water to meet the irrigational needs during the surplus water periods in the summer. However, in order to obtain a significant output from the reverse flow plant, there are two alternatives (a) the reverse flow period must start with the Equalizing Reservoir full, or (b) The Feeder Canal must be modified to permit greater reverse flow for lower reservoir elevations.

Considering (a), it is not efficient from a water use standpoint, to pump for pumped storage <u>after</u> the surplus water season has ended in an all-hydro system, as in the case at Grand Coulee. It has been shown in calculations, and is logical to reason that after surplus flow has ended, no further storage can be accomplished— only a transfer of storage. Since lack of sufficient storage, not lack of installed capacity is the major limitation, pumped storage is not a reasonable solution to the problem.

Let us consider the case of 1 gallon of water, in an extremely hypothetical case. This 1 gallon of water is pumped out of Lake Roosevelt into the Equalizing Reservoir, and the power necessary to lift it up would require, let us say, releasing 1 gallon from Roosevelt, passing through Coulee's main turbines. This gallon would proceed down stream and be stored at, and eventually pass through the turbines at Chief Joseph. However, as far as Coulee is concerned, this water is gone.

At this time, Lake Roosevelt is minus 2 gallons, reducing the hydraulic head at Grand Coulee by a small amount. While up in the Equalizing Reservoir this 1 gallon suffers some loss due to seepage and evaporation. Later, when it is released from storage and flows reversibly through the pump-turbine units, it generates electrical power, which, within the limits of the efficiency of the operations involved (Coulee turbines and generator, pump and motor up, and turbines and generator in reverse flow) tends to compensate for the electrical energy expended in storing the water.

However, 2 gallons were drained from Roosevelt, and somewhat less than 1 gallon returned. Thus, from the standpoint of water use, there has been a loss of 50%--or very inefficient use of valuable, irreplacable water.

It is clearly more economical in an all-hydro system to store the water in the main stem reservoirs.

If steam plants of sufficient size and of high efficiency and low load factor should be built in the neighborhood of Grand Coulee, the pumping problem might be simplified, and from a water efficiency standpoint considerably improved, although a transfer instead of an increase of storage would still be the net result after surplus flow cease.

In considering 3 b), it can be seen that any change in the Feeder Canal would be a major construction job. If it were possible, the cost would probably be such as to destroy the economic advantage enjoyed in the initial consideration of this problem.

4. Further, the actual ability of the Equalizing Reservoir to operate satisfactorily at the upper elevations is questionable, as a fault in the basin exists which may cause serious leakage at or near the full point of the reservoir. This may not be serious, or may be corrected, as a matter of joint concern to the irrigation and power interests.

5. In years when there is sufficient time to pump a significant amount of water beyond the irrigational needs, using surplus water and secondary power, added storage has been contributed to the system, assuming that Lake Roosevelt and all upstream reservoirs are already full. Any additional storage is a gain to the system in added firm capacity,

and can be justified both in water and dollars economy.

Evaluation of Daily Pumped Storage. The function of pumped storage is (a) to trade cheap power for high cost peak energy, and (b) increase firm capacity of the system. In the Pacific Northwest, most critical shortages arise from low river flow, rather than from load fluctuations or lack of installed capacity. Actually there is always a power shortage, as shown by the high load factor of secondary energy whenever available. The completion of the downstream plants now under construction and plants in the upstream tributaries will make this even more true. Installed capacity will be high, limited periodically by low river flow.

If a considerable building program is undertaken, as has been suggested, giving large steam generated capacity to the system, the present problem might approach the classical. However, at present, depending on river flow, the problem becomes one of choice of water storage and the most efficient use of each gallon of water.

Thus, pumped storage would increase the peak capacity, but it would not represent the most economical use of the water. This is shown in Calculations and as discussed in Evaluation of Yearly Pumped Storage.

Since low water and low firm capacity periods coincide, a daily pumped storage program is a questionable solution, because we would be simply increasing the peaking capacity at the expense of the stored water, which would be irreplacable.

One complicating factor in any consideration of pumped-storage on a 24 hour basis, is the limitations imposed by the Feeder Canal.

To operate 6 pump-turbine units reversibly, the Equalizing Reservoir must be very nearly full. This means that before a truly 24 hr. pump and return schedule could operate, using 6 units, the drawdown caused by fall irrigation would have to be replaced. This water - up to 3.2 feet of the reservoir full elevation of 1570 feet - would serve largely as dead storage, usable only when a smaller generating capacity was used. Six pumps can operate in filling the Equalizing Reservoir up to an elevation of 1567.6 feet, so the Feeder Canal would not be a severe limitation on filling time to the necessary elevation. The question of sufficient time for pumping this water during surplus water periods is a major obstacle. Only surplus water pumping for this dead storage could be justified. As previously noted, a rather narrow margin above the 140 day minimum required for irrigation water pumping is available during about ½ of the years studied, for the regulated river conditions assumed in the C-2 phase. At least part of this margin of surplus pumping time will come in the spring, and very seldom will run far into September. Irrigation will continue through the month of October. Thus, the pumping for dead storage becomes a definite draw-back.

Complete rejection of the 24 hour pump and return schedule is based on the previously proven fact that in an all-hydro system, as this essentially is, pumped storage does not provide for the most efficient use of water. Pumped storage can only be justified in 3 cases:

a) In a steam-hydro system, where a sufficient economic advantage between peak and off-peak energy exists.

b) In an all-hydro system where all pumping can be done during periods of surplus water, using off-peak or ideally, dump power for pumping.

c) Possibly in an all-hydro system during periods other than surplus flow, where installed capacity for peaking is insufficient, and must be obtained even at the sacrifice of water reserves.

None of the above conditions exist at Grand Coulee Dam, at present, or in the foreseeable future.

<u>A Tabulation of the Factors for and Against the Construction of a Pumped Storage Plant at Grand Coulee.</u>

<u>Factors in Favor of Construction of a Pumped Storage Plant</u>

1. Low initial cost per kw for construction.
2. High cost of peak energy from the present steam plants.
3. In the ideal case, a pumped storage plant could furnish additional storage to the power system.
4. The pumped storage plant could be constructed and in operation if necessary, in the near future.
5. Re-use of the water after release from the Equalizing Reservoir by Grand Coulee Dam and all of the downstream plants.
6. Utilization of the present equipment more months out of the year.
7. The conservation or resources aspect - utilization of a natural power drop. Public appeal.
8. Difficulty of placing future steam plants in the area. No high grade fuel deposits.
9. Low fixed cost on the investment. Maintenance of the pumping plant is required whether pumped storage is used or not.

10. Presently installed pumps would probably operate reversibly, although at a reduced maximum output.
11. The present 6 pumps are not too satisfactory, and the Bureau of Reclamation might be glad to try some other type of unit, such as reversible pump-turbines with wicket-gates.
12. Wicket-gate pump-turbines as made by Allis-Chalmers could be made to fit into the present pump pits of the pumping station. Elevation should be no problem, as pumping is usually done at high water elevations in Lake Roosevelt.
13. If a schedule of yearly pumping and return were followed, all of the pumping would be done when Lake Roosevelt is high and the head low, and the head would be high during periods of reverse flow occurring during periods of low river flow. This gives an advantage by increased output and over-all efficiency.
14. Water necessary to give significant peaking energy over a 7.85 week period draws down the Equalizing Reservoir only 3.3 ft from the full elevation. This is not enough of a drawdown to be a handicap in spring irrigation.
15. In the majority of years, there is more than enough time in the surplus water period to pump the predicted irrigation water requirements. In an average year this could allow between 600,000 and 1,000,000 acre-ft of surplus water to be put into pumped-storage.

Factors Against Construction of a Pumped Storage Plant at Grand Coulee.

1. There is a relatively short ideal pumping period (surplus water period).
   a) In many years, there is not enough time to pump water beyond the predicted ultimate irrigation water requirements from surplus water. Although there is no direct correlation, dry winters must follow dry summers in certain years, permitting no extra storage for pumped storage when it is needed most.
   b) The irrigating season is considerably longer than the ideal pumping season. This means that although the Equalizing Reservoir may be full at the end of the surplus water pumping season, fall irrigation - which continues into October - may draw the reservoir down below the reverse flow elevations.
2. Absence of efficient steam plants in the region. These are necessary for all pumping except during excess water periods. Pumping using hydro energy is not justified except during surplus flow periods.
3. The distance of the plant from the load centers. Peaking plants should be near their load.
4. The basic economic advantage usually achieved by pumped storage is destroyed by the distance from the load centers and the resultant low value per kw-hr at Grand Coulee. There is little or no price differential between firm and peak energy at Grand Coulee.
5. Limitations of the Feeder Canal. Reverse flow limitations are very severe, allowing 6 units to operate reversibly for only 3.3 ft of

draw-down from reservoir full. Pumping limitations will also be a factor in filling time, especially when the final 10 or more pumps are installed.

6. Necessity of operating with the Equalizing Reservoir full.
   a) As pointed out in number 1 above, fall irrigation may make this very difficult.
   b) The Equalizing Reservoir may leak very badly at the upper elevations. This leakage may be very difficult or impossible to correct.
7. Except through use of off-peak steam energy or hydro energy from surplus water, pumping for pumped storage does not represent the most efficient use of the river water. If pumping must be done using stored water reserves, the reserve water could be used more efficiently directly through the turbines in the main steam plants.
8. Absence of severe peak load periods in the system.
9. The type of power shortages in the system. The most severe power shortages are due to low-water years and are cyclic. This does not require peak-power for remedy, but steam plants to operate on base load for several months at a time.
10. The effect of upstream dams will make pumped storage less necessary.
11. The great cost of modifications to eliminate the limitations of the Feeder Canal for ideal and unrestricted operation of the Equalizing Reservoir.
12. Reduction of the rating of the present units for reverse operation. Their rating would probably be approximately 60% of the pump rating.

13. Greater cost of reversible units.
14. The high load factor of secondary energy, making it not really "cheap" for pumping. It is very necessary for the regions economy.
15. The effects of the possible third powerhouse at Grand Coulee Dam.
    a) It would reduce surplus water periods very greatly.
    b) It would add capacity for peaking, if capacity were ever a factor.

SUMMARY AND RECOMMENDATIONS. No final recommendation can be made on whether or not pumped-storage should be used at the Grand Coulee pumping plant until it is definitely determined if it is possible. This will not be known until the Equalizing Reservoir is finally filled (in 1958 according to the projected schedule), and the extent and possibility of repairing leakage in the Reservoir are determined.

Should the leakage be significant at the upper reservoir elevations and be impractical to seal off, the only alternative for pumped storage would be to modify the Feeder Canal or install penstocks directly to the bottom of the Equalizing Reservoir. Both of these alternatives are so expensive as to be considered impractical at this time.

In evaluating the four alternative solutions of the pumped storage problem, Alternatives No. 1 and No. 2 appear to be the most practical from a physical and economic point of view. In the cost approximations made for these two alternatives, the cost per kw were nearly the same, approximately $30 per kw in both cases. This is extremely low, and is to be compared with an average of $170 per kw for new steam plants and $258 per kw for new hydroelectric installations.

Alternative No. 2 or the installation of 6 specially designed reversible units of the wicket-gate type seems to be the best solution. These units will give a considerably greater output in both kw and kw -hr than the present units operating reversibly, giving a greater installed peak capacity. They can be designed to operate at two speeds for greater efficiency if necessary. Since the pump-turbines can be regulated by use of their wicket-gates, they can utilize the available water storage to the best advantage in furnishing peaking energy. As these units would be separate from the present pumping units, the construction and testing could be carried on without interfering with the current pumping requirements.

In studying the economics of the problem, the value of energy at Grand Coulee must be considered. Since the value per kw-hr is very low, due to the high transmission charges to the distant load centers, the value of the peak energy is very nearly that of any other increment of energy. This may be partly due to a somewhat artificial rate structure, but at present this is the case. This fact makes even the standard case of pumping using off-peak steam energy somewhat doubtful of economic justification. However, by providing peak energy when it is needed, the firm power commitments can be increased and the over-all capability of the system increased. This is an economic advantage to any system, even though money might be lost on the peak energy sold.

The most efficient use of the available and possible storage is of vital concern. Any system of pumped storage which can produce net additional storage provides added energy to the system, plus peaking capacity. Any plan which provides for just a <u>transfer</u> of storage provides only additional peaking capacity. To be justified, this transfer must take place without any loss of water, or must be pumped from some external energy source using either dump hydro energy of off-peak steam energy.

1. Any plan which uses hydro energy for pumping during surplus water and surplus energy periods, provides the ideal case in dollars and water economy. Additional storage and peak energy is provided free.

2. If pumping is done during periods of excess water using off-peak steam energy, additional storage is provided but at a lesser economic gain. In both of the above, a total energy gain for the system is achieved.

3. If steam energy is used to pump from water already stored but not surplus, only a transfer has occurred, and peak energy is provided.

4. If hydro energy is used to pump during periods when water is not surplus for either pumping or storage, a transfer and a loss of water have both occurred, with a resultant net loss of system hydro energy paying for the peak energy provided.

These alternatives are acceptable in the order given above. None but the first 3 should be considered, except in a case where peaking energy must be bought at any price. The installed capacity on the Columbia River is becoming so great that additional capacity, even for peak energy, need not be purchased at the price of wasted water.

The fourth, unacceptable plan for pumping into storage, in the absence of efficient steam plants in the area, is the only possible plan for pumping at Grand Coulee during the winter months, as would be necessary in a schedule involving a 24 hour pump and return cycle. Thus, using the pumped storage plant in any plan requiring pumping during the winter must not be considered until steam energy for pumping becomes available, or surplus flow periods occur in the winter months allowing pumping from excess hydro energy, not taken from storage. Until one or both of these things occur, the pumped storage plant is limited to the first pumping alternative, or doing all of the pumping in the summer surplus flow periods.

The remaining pumping alternative involving a yearly cycle of pumped storage meets serious time limitations and physical handicaps. Considering (a) the long irrigation season, (b) the relatively shorter period of surplus water over Grand Coulee Dam and the ideal pumping season, (c) the fall drawdown of the Equalizing Reservoir after the end of surplus water and ideal pumping, (d) the limitation of the Feeder Canal, permitting 6 unit reverse flow operation for only the upper 3.3 ft of Reservoir drawdown, (e) possibility of severe leakage making the holding of the Reservoir at its maximum elevation impractical or impossible, it does not seem wise to install any system of reverse flow operation at this time.

At some future date as (a) such Equalizing Reservoir leakage occurs is corrected, (b) additional pumping capacity is required to meet irrigation needs, (c) the load factor of the Northwest Power Pool reaches a more normal value of about 60%, as industry of a wider variety is built up in the area, and peak power is more at a premium, (d) additional steam plants of high efficiency are constructed in the area to furnish off-peak energy for pumping, (e) the Columbia River becomes more completely regulated by completion of Hungry Horse, Albeni, Libby and Glacier View Dams, giving a longer average ideal pumping season in the summer, and winter periods of excess flow in many years, this reverse pump-turbine plant would be advisable. Many of these things should occur in the next ten (10) years. As noted earlier, completion of the up-stream dams will both make this project more possible and at the same time less necessary. However, Major Hutton once said at Coulee Dam, "We may at some future date have enough bread, enough shoes, and enough refrigerators, but we shall never have enough power." If added water storage can be accomplished and peak energy made available by use of a pumped storage plant, either by well planned utilization of the extended surplus flow periods produced by river regulation or by using off-peak steam energy, a gain will have been made. Firm capacity will be increased, and an economic advantage achieved. And the cost per installed kilowatt for a pumped storage plant at Grand Coulee is very low, making the initial investment and fixed costs economically attractive.

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