Kaplan Turbine Repair Strategy

John Day Units 1-16, Lower Monumental, Little Goose, and Lower Granite Units 1-3

VOLUME I

John Day

Lower Monumental

Little Goose

Lower Granite

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EXECUTIVE SUMMARY

Background

The 25 Baldwin-Lima-Hamilton (BLH) Kaplan units installed at the John Day, Lower Monumental, Little Goose, and Lower Granite projects were designed and manufactured over 35 years ago and are known to be prone to blade mechanism failure from initial installation. All the turbines have had blade operating mechanism repairs or modifications from original design at least once. The principal design feature of a Kaplan turbine is the ability to adjust the blade angle to accommodate a wide operating range at good efficiency. Three failures of the blade adjustment mechanisms of these BLH turbines have occurred since 1999. Historically when a failure occurred in the blade adjustment mechanism, it was always restored to be able to operate in a *Kaplan* mode (i.e., the blades could change their pitch). Such a repair to a single unit would cost about $2.6 million and may take as long as 24 months. It also is possible to lock the pitch of the blades at a fixed angle. If this is done, the unit would be considered to operate in a *propeller* mode. Converting a Kaplan unit to a propeller unit can be done relatively quickly and at a much lower cost than a full repair. The estimated cost is $245,000 and the conversion may take as long as 6 months. However, there are some performance impacts with this *propeller* operation (i.e., less maximum power, peak efficiency, and operating range). There are also operational limitations, principally environmental, which limit the number and location of units which can be operated in propeller mode.

Objective

This report pre-plans a repair strategy for these 25 identical units if future additional failures in their blade adjustment mechanisms occur. This strategy will shorten the decision-making time, minimize the outage period, and also reduce the cost of some repairs.

Recommended Repair Strategies

John Day Turbines

The Bonneville Power Administration established the limit for up to eight turbines to operate as propeller type at John Day. It was reasoned that more that eight propeller units at John Day might compromise the operation of the electrical transmission system. Therefore, the recommended repair strategy at the John Day powerhouse is to only repair the units back to Kaplan operation which are required for fish passage. These would be units 1 and 2. Any of the others that experience a failure in their blade adjustment mechanism should be repaired to operate permanently as propeller units. When a unit is operated as a propeller unit, it will be set to run at peak efficiency at a fixed power output with a blade angle of 29 degrees.[1] As project head changes, power output of the propeller turbine will vary with wicket gate opening to maintain operation at peak efficiency. The recommended strategy for units 1 and 2 is to return them to Kaplan type as soon as possible using an Indefinite Delivery Indefinite Quantity (IDIQ) type contract, project maintenance personnel, or a combination of the two. Economic results indicate permanent repair to propeller (strategy B) should be followed until as many as eight units have failed. Beyond eight units, the permanent repair strategy should be re-evaluated considering a rehabilitation strategy (i.e., runner repair before failure) as opposed to continued repair after failure.

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[1] This blade angle is currently satisfactory for fish passage. If future research indicates a different angle is better, the new angle will be used. It is possible to change the blade angle of a unit that was previously set at 29 degrees.

Lower Snake Turbines

The recommended repair strategy for the three BLH turbines at each of the studied Lower Snake River powerhouses is to only repair the units back to Kaplan operation which are required for fish passage. These would be units 1 and 2. If unit 3 experiences a failure in its blade adjustment mechanism, it should be repaired to operate permanently as a propeller unit. When operated as a propeller unit, it will be set to run at peak efficiency at a fixed power output with a blade angle of 29 degrees. As project head changes, power output of the propeller turbine will vary with wicket gate opening to maintain operation at peak efficiency. The recommended strategy for units 1 and 2 is to return them to Kaplan type as soon as possible using an IDIQ contract, project maintenance forces, or a combination of the two.

Justification for Recommended Strategy

In order to evaluate the various strategies, a series of economic scenarios were developed to estimate a number of linkage failures that could occur over the next twenty years. Each strategy was tested over a range of potential linkage failure scenarios.

There are no significant impacts to the operation of any of the four powerhouses if the recommended strategy is followed. The recommended strategy has no significant environmental impacts; however, regional environmental requirements may change requiring consultation. The cost to convert a failed turbine to operate as a propeller unit is 10% of the cost to repair it to operate as a Kaplan unit. The economic difference (savings) in the *net present value*[2] during the next 20 years of choosing the recommended strategy over the historical repair strategy (i.e., always repairing a failed unit to continue to operate as a Kaplan unit) is about $22 million. This assumes eight Kaplan units fail at John Day and three at the Lower Snake River plants (total of eleven failed units) during the next 20 years. Sensitivity analyses were performed using different interest rates, energy value inflation rates, repair cost inflation rates and different repair costs. In every case analyzed, the economic analyses still favored the recommended strategy.

Life Extension of Studied BLH Kaplan Turbines

Although not specifically identified in the 2406 subagreement, this report (Appendix J) additionally outlines "modify before failure" options that could be exercised before a failure occurs, which reduce the risk of a failure and subsequent outages and collateral damage. These options are complementary to the recommended repair strategy and should be considered in additional detailed studies. They include choosing higher performing lubricants and lubricant additives, as well as performing non-destructive testing and replacement of some of the internal parts without having to *unstack* (i.e., completely disassemble) a generating unit.

[2] Net present value includes differences in system generation benefits, as well as repair costs including the effects of interest and inflation during the period of evaluation.

ACRONYMS AND ABBREVIATIONS

AC	Allis Chalmers (turbine unit manufacturer)
BLH	Baldwin-Lima-Hamilton (turbine unit manufacturer)
BOP	best operating point
BPA	Bonneville Power Administration
CFD	computational fluid dynamics
CFE	clean fish estimate
cfs	cubic feet per second
Corps	U.S. Army Corps of Engineers
E&D	engineering and design
EDC	engineering during construction
ERDC	Engineer Research and Development Center
ESBS	extended length submerged bar screens
FCRPS	Federal Columbia River Power System
FEA	finite element analysis
FFDRWG	Fish Facility Design Review Work Group
FPOM	Fish Passage Operations Maintenance Coordination Team
FPP	Fish Passage Plan
GDACS	Generic Data Acquisition and Control System
GWh	gigawatt hour(s)
HAC	Hydropower Analysis Center
HDC	Hydroelectric Design Center
HLH	heavy-load hours
HYSSR	Hydro System Seasonal Regulation (model)
IDIQ	Indefinite Delivery Indefinite Quantity (contract)
IRR	internal rate of return
ISO	International Standards Organization
JDA	John Day Dam
kcfs	thousand cubic feet per second
LDV	laser doppler velocimeter
LGS	Little Goose Dam
LLH	light-load hours
LMN	Lower Monumental Dam
LWG	Lower Granite Dam
MOP	minimum operating pool
MVA	megavolt ampere
MW	megawatt(s)
NDT	non-destructive testing
NMFS	National Marine Fisheries Service
NPV	net present value
O&M	operation and maintenance
PDT	Product Delivery Team
PIT	passive integrated transponder
PNNL	Pacific Northwest National Laboratory

ACRONYMS AND ABBREVIATIONS (CONTINUED)

psi	pounds per square inch
psia	pounds per square inch absolute
PT	dye penetrant testing
PV	present value
RCU	relative cost of unavailability
rpm	revolutions per minute
RSW	removable spillway weir
S&A	supervision and administration
S&I	supervision and inspection
SE	standard error
SP	super-peak (hours)
STS	submersible traveling screens
TDG	total dissolved gas
TEAM	Turbine Energy Analysis Model
TSP	Turbine Survival Program
TSW	top spillway weir
UT	ultrasonic testing
VBS	vertical barrier screen
WECC	Western Electricity Coordinating Council

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1.0. REPORT OBJECTIVE

The objective of this report is to develop a repair strategy plan to minimize decision-making time and expedite, as appropriate, repairs should a mechanical failure occur in the blade adjustment mechanism in turbine units 1-3 at the three Lower Snake River powerhouses or units 1-16 at the John Day powerhouse. Additionally, this report will provide recommendations addressing the need for critical spare parts, as well as preventative measures that can extend the life of a unit.

2.0. BACKGROUND

There are 25 identical Kaplan turbine units installed the John Day, Lower Monumental, Little Goose and Lower Granite Powerhouses. All were designed and manufactured by a company named Baldwin-Lima-Hamilton (BLH). The age of these units ranges from 34 years (Lower Granite) to 41 years (John Day). When these turbines were relatively new, a pattern of failures began which required complete unit disassembly to repair. The ultimate cause was a design error of the studs which attached the piston cap to the blade servomotor piston in the runner hub. Eventually repair was required for 22 of the 25 units. The last three units, installed in the Lower Granite powerhouse, were repaired prior to their installation.

Another weak point in the original design at John Day was the small radius at the base of the linkage eye ends. To address this failure point, 0.5-inch of material was machined off the base of each eye end, leaving a larger radius at the transition to the stud section. An additional 0.5-inch spacer was added to each eye end shim to maintain the original lower link pin height above the crosshead. This work was completed during the early 1980s and no additional eye end failures have occurred to date.

As a result of these early failures, a significant amount of research and testing was performed over the years in an attempt to better understand the nature of wear and fatigue in the turbine parts as well as to explore means of prolonging the remaining life of the blade adjustment mechanism. This work included trying different lubricating oils, changing the bushing materials, performing extensive field “stick-slip” tests (Corps 1983), strain gauging of hub internal parts, hiring a lubrication oil expert to analyze the wear of the John Day hub trunnion bushings and investigating oil additives to increase oil lubricity (Corps 1987).

More recently, research performed by Powertech Labs (2005) revealed much more information about the actual friction coefficients of the Kaplan blade adjustment mechanism when typical loads and speeds are used. The coefficients are much higher than the original designer used which results in an uneven, jerky motion of the affected parts. The testing and research work is discussed in more detail in Appendix J, *Modify Before Failure*.

Beginning in 1999, failures in the blade adjustment mechanism began to occur in these units (see *Memorandum for Record* by R. Wittinger, CENWP-HDC-M, dated 3 July 2006). In 1999, a link failed in unit 2 at Lower Granite. In 2001, an eye end failed in the same unit. The Lower Granite unit received interim repairs in 1999 and 2001. A permanent repair was accomplished by a contract that began in December 2005 and was completed on 29 January 2009. Link pins in Lower Monumental unit 1 failed in spring 2005 and also in John Day unit 16 in spring 2006 (see Appendix A, *Turbine Engineering*).

It should be noted that BLH designed and manufactured other similar Kaplan turbines for the U.S. Army Corps of Engineers (Corps), as well as other agencies. However, the recent failures observed appear to be unique. For example, the 22 turbines at The Dalles powerhouse are also BLH units and are older than the John Day turbines. However, no similar failures at The Dalles have occurred.

3.0. CONSIDERATIONS

3.1. POWERHOUSE OPERATIONS

3.1.1. John Day

Unit 5 is the primary generator for providing power for station service. There is electrical equipment installed on this unit which is fed directly from the generator. This allows main unit 5 to be able to provide station service even if the main transformer for that unit is out of service or the transmission line it is connected to is unavailable. However, any of the other first eight main units can be used to provide station service power on a temporary basis. Therefore, converting unit 5 to a propeller unit permanently would impact powerhouse operations unless modifications were made to one of the other seven main units. The cost of these modifications is about $150,000. There are no other operational impacts should any other units be operated as propeller units on a permanent basis. There are impacts if units 1 or 2 are made into propeller units, but these are biological impacts and not operational (see Appendix K, *Operational Considerations*).

3.1.2. Lower Snake River

There are no operational impacts should unit 3 be operated as a propeller unit on a permanent basis. There are impacts if units 1 or 2 are made into propeller units, but these are biological impacts, not operational (see Appendix K).

3.2. ENVIRONMENTAL

The biological impacts of converting units 1 or 2 to permanent propellers could affect both adult and juvenile anadromous salmonids at any of the four project sites. The Corps' Fish Passage Plan (FPP) specifies the criteria for operating turbine units for fish passage, both upstream (adults) and downstream (juveniles). Operating priorities take into consideration the tailrace flow conditions for adult salmonid attraction, flow at juvenile outfalls, and overall tailrace egress for juvenile fish. If these operations are limited by converting one of these units to a permanent propeller, one or more of these operating priorities could be compromised, resulting in less than ideal passage conditions. The effects of these changes will be, in large part, dependent on the site where they occur. In the event of a secondary failure in these units, (e.g., presuming unit 2 has been repaired to a propeller and unit 1 also fails during the peak fish migration season), the potential delay in migrations could result in elevated risk to the affected populations. It may be prudent to repair one or both of these units at a time to mitigate the effects on the migrating fish populations with the preferred alternative being Kaplan type units (1 and 2) for maximum operational flexibility, or make them permanent propellers if it is biologically benign at a particular project. Appendix B, *Biological and Environmental Considerations*, contains more detail on the biological and operational considerations for both adult and juvenile fish passage.

3.3. TRANSMISSION SYSTEM

All the hydropower projects considered in this study provide significant benefits to the Federal Columbia River Power System (FCRPS). From a power benefits perspective, there are two key factors to consider when reviewing the system impacts of fixing blades: capacity and load-following capability. Maintaining capacity is important to ensure a reliable power system as load growth occurs in the FCRPS. Load-following capability is increasingly important as wind generation increases dramatically in the region and hydropower plants are being called upon on an increasing basis to maintain system stability and provide generation flexibility.

Fixing blades limits the operating range of a unit and also the peak power of the unit as compared to the same unit with full Kaplan capabilities. While the potential limitations at these projects resulting from fixed blade repairs represent a fairly small fraction of the capacity and load following capability of the system as a whole, there are significant considerations relating to system operation that should be taken into account. From Bonneville Power Administration's (BPA) perspective, reductions in unit capacity and reduction in operating range which impacts load following capability are of most concern with fixed-blade repair scenarios (see Appendix H, *Generation and Transmission System Considerations*).

Due to concerns about loss of capacity and ability to load follow, BPA recommends that a maximum of eight units at John Day and one unit each of the BLH units at the three Snake River powerhouses be considered for permanent conversion to fixed blade operation due to blade linkage failures. Other priorities such as fish priority status of units (see Appendix B) will likely determine whether a unit is repaired to full Kaplan capability if blade linkage failure occurs.

4.0. DECISION ANALYSIS

4.1. STUDY ASSUMPTIONS

The study assumptions listed below were needed to perform the work of developing the repair strategy and to perform the economic analyses. They do not necessarily represent decisions managers have made or are requirements for project operation and maintenance (O&M) personnel. They simply represent the best guess the Product Delivery Team (PDT) was able to make with the information available.

1. The analysis will consider that if a unit is to be made a permanent propeller the oil will remain in the hub with manageable oil leakage.
2. The basic repair strategy (Strategy A) for study analysis is to restore all failed units by a contract to full Kaplan status assuming complete disassembly is required. The recent repair of Lower Granite will form the basis for costs, while the repairs in the 1980s will form the basis for scheduling a contractor repair assuming complete disassembly is required. Walla Walla District operations will take lead on assembling information.
3. The Allis-Chalmers turbines installed in units 4, 5 and 6 at Little Goose, Lower Monumental, and Lower Granite will be included in the study (for the purpose of development of power benefits) and assumed for this study that they never will have a blade adjustment failure.
4. Both with-screen and without-screens seasons will be considered.
5. Separate turbine performance information will be required for with and without screens operation for existing Kaplan and selected propeller turbines at each site.

6. The with-screen season will be the same as the FPP specific to each site.
7. The economic duration of the study will be 20 years starting on 1 October 2009.
8. The 50 years (1928-1978) of hydropower regulation data with current operation at minimum operating pool (MOP) will be used for the hydraulic information with the sensitivity of the two different operating seasons considered.
9. The study will consider various ways of restoring a unit after failure.
10. Two repair strategies will be considered: a strategy in which a failed unit will be restored to full Kaplan service and a strategy where a failed unit will be repaired to fixed-blade propeller operation.
11. No units will be retired. All units will be returned to service as either a Kaplan or propeller.
12. The repair strategy recommended by the PDT for each powerhouse is based on current operating requirements.
13. The study will assume that a minimum of one complete set of spare parts for the turbine blade operating mechanism is available for immediate use should a failure occur.
14. Should a failed turbine runner be repaired to full Kaplan operation, the work will involve the unstacking of the unit and the disassembly of the turbine runner. The runner hub parts and the consumable parts (i.e., gaskets, O-rings, etc) will be replaced as with the recent unit 16 repair at John Day Dam.
15. The average gross operating head for the fish passage and non-fish passage season will be considered in the analysis.
16. Initial turbine performance information for economic analysis of the propeller runners will be prepared at 29 degrees blade angle.
17. In the event of a major maintenance outage (rewind, etc.) replacement of the linkage pins in-place as a preventative measure will be considered.
18. The “modify before failure” strategy will be in a separate appendix of the report and include previous assumptions above as they apply. This strategy will not be economically evaluated but portions of it may be recommended.
19. The cost and schedule of the next failure or inspection at John Day that requires lowering of the hub cone will include the cost and lead-time to have a new draft tube platform fabricated.
20. An annual outage schedule for routine maintenance at each project will be determined by Portland and Walla Walla District operations and used in the power benefit analysis.
21. The repair duration for a failed unit will be 6 months for a fixed blade repair and 18 months for a Kaplan repair.
22. Funding will be available to make any repair. Expense funding will be used until a subagreement is in place where upon the expense account would be reimbursed.
23. A unit repaired to operate as a propeller unit will be moved to last in the plant loading order making it a “last on/first off” unit.
24. Personnel experienced in directing the disassembly, repair and reassembly of large Kaplan turbine driven generating units are rare.
25. For the Lower Snake plants, one strategy will be used for all three plants that considers the overall least-cost strategy.
26. Since random failure of other components besides the runners including fish screens, bearings, transformers, etc will occur equally in the base case and the three strategies, they will not be considered as affecting the outcome of the analysis.

4.2. KAPLAN OR PROPELLER TURBINE

From the standpoint of operating a powerhouse, there are no significant operational differences if a turbine remains a Kaplan type or is converted to propeller type. However, there are some performance differences. Propeller units have a smaller operating range; the difference between the minimum and maximum power output they are capable of at a particular net head is much smaller than a Kaplan unit. In addition, the maximum power output for the propeller unit would be less than that of a Kaplan unit. For an actual comparison of the operating ranges and maximum power of the turbines operating in each mode, please compare Appendix A, Tables A-4 and A-7 for the no screens condition, Tables A-5 and A-8 for the submersible traveling screens (STS) condition, and Tables A-6 and A-9 for the extended length submerged bar screens (ESBS) condition. Because of this, the range of water discharge rate a propeller unit has would be proportionally smaller than that of a Kaplan unit.

At John Day there are so many units (16) that, from a system generation and transmission viewpoint, there would be no impacts if numerous units (perhaps as many as half) were operated as propeller units. A recent rigorous study of the McNary powerhouse that examined numerous means of rehabilitating the turbines resulted in a recommendation to replace all 14 existing Kaplan turbines with propeller type turbines. Moreover, the turbine selection study performed during the planning of the second powerhouse at Bonneville considered a configuration involving half propeller units and half Kaplan units. The Kaplan scheme was selected because there was not much cost difference and it was determined that maintenance would cost less using identical units.

4.3. ENVIRONMENTAL

Since a propeller unit has a lower maximum power output than a Kaplan unit and a limited operating range, there could be significant impacts to anadromous fish such as salmon and steelhead. These differences are important to salmonid migrations, both upstream (adults) and downstream (juveniles), and are the reason the two shore-side units (units 1 and 2) at each of the four powerhouses need to remain Kaplan type, even though one could be operated as a propeller on a temporary basis. While it would be possible to operate unit 1 or 2 as a propeller unit (such as Lower Monumental unit 1, which has been operating in propeller mode since October 2005), there are other failures the generating unit could experience, such as a generator winding failure, which would involve a lengthy outage. For example, if this happened to Lower Monumental unit 2, both adult and juvenile fish passage could be impacted. If both units 1 and 2 failed for any of these reasons during peak migration periods, the impacts to adult and juvenile fish would likely be amplified resulting in impeded migration of the adults and/or delay in egress of the juveniles. Delay in egress would likely result in increased predation in the dam’s tailrace.

4.4. ACQUISITION PLANNING

The work required in the recommended strategy involves all of the following tasks:

- Repairing a failed unit back to a Kaplan type.
- Temporarily converting a failed Kaplan unit to a propeller type.
- Permanently converting a failed Kaplan unit to a propeller type.

Of these three tasks, the first one is the most expensive, as well as being the most time and labor consuming task. Disassembling, repairing, modifying, reassembling, and testing large Kaplan type generating units requires supervising personnel who have prior similar experience. However, there are at least four firms or organizations that have personnel with the requisite experience and interest in performing such work.

The Corps' own maintenance team also has personnel who are qualified to disassemble and reassemble a Kaplan unit. In the past, many units at the John Day powerhouse were disassembled and repaired by Corps' personnel using hired labor. Recently, John Day unit 16 was repaired by project maintenance personnel. In addition, maintenance personnel at Lower Monumental are planning to repair unit 1 in 2009. The downside of performing a unit disassembly with the Corps' maintenance personnel is the deferment or cessation of their normal maintenance work.

The best solution would involve using the Corps' maintenance personnel to perform quality assurance and use an IDIQ contractor to perform the work. This is the recommended acquisition strategy for a full Kaplan repair.

The other two repairs included in the recommended strategy are relatively simple and could be done either with Corps' maintenance personnel or a contractor. Using an IDIQ contractor to perform either of these tasks would likely result in the shortest unit outage time. Detailed schedules for strategies A, B, C and temporary repair are located in Appendix G, *Construction Schedules*.

4.5. COSTS

Costs were developed for the three strategies covered in this report. In the case of the repair to full Kaplan function, the costs are based on the work performed for John Day unit 16 repair and Lower Granite unit 2 repair, both jobs were similar to the proposed repair methodology for this report. In the case of the conversion of a failed unit to a permanent fixed-blade propeller, the costs are based on a best estimate of the work involved.

Non-contract costs such as engineering and design (E&D), project management, contracting, engineering during construction (EDC), supervision and administration (S&A), and project support are assumed to be about 20% of the contract cost for a full Kaplan repair. This is based on common estimates for other rehabilitation jobs of similar nature. For the smaller permanent conversion to a fixed-blade propeller, the non-contract cost is estimated to be greater than 20%. A contingency of 15% of the repair costs is used for each of the three strategies to account for unforeseen circumstances. A summary of the estimated repair strategy costs are shown in Table 1; more information can be found in Appendix F, *Cost Estimates*.

Table 1. Estimated Repair Strategy Costs ($1000s)

Repair Strategy	Repair Costs	Non-Contract plus Contingency Costs	Total Estimated Repair Costs (Oct 2009)
A. Temporary Propeller then Full Kaplan, Regular Contract	2046.0	689.1	2735.1
B. Permanent Propeller	180.0	65.0	245.0
C. Full Kaplan, IDIQ Contract	1875.0	629.3	2504.3

4.6. BENEFITS

Project energy production and the corresponding project energy benefits were estimated for John Day, Lower Monumental, Little Goose and Lower Granite under the study base case and each of three Kaplan repair strategies (see Section 5). The energy production estimates were obtained using the Turbine Energy Analysis Model (TEAM). The energy benefits estimates were obtained using the Excel spreadsheet COMPARE, which applied energy values developed by BPA to the corresponding energy production estimates from TEAM.

Since TEAM was designed to run on a single project basis, a separate setup of the model was developed for each of the four projects. For each project, TEAM provided weekly estimates of project energy production over the 50-year hydrologic period of record from August 1928 through July 1978. Project operational input to TEAM included: (1) forebay elevations and flow releases obtained from a Hydro System Seasonal Regulation (HYSSR) simulation of project monthly operation over the 50-year hydrologic period of record; (2) tailwater rating tables; (3) equations defining turbine-generator performance (with and without fish screens) for the three turbine types and two fish screen types used to model the operation of the four projects under the various study scenarios; (4) unit loading orders; (5) unit maintenance schedules; (6) spill for fish requirements; and (7) powerhouse minimum flow requirements. After TEAM had converted the project monthly forebay elevations and flow releases to weekly equivalents, the model shaped each weekly flow release over three sub-periods (super peak - SP, heavy load hour - HLH, and light load hour - LLH) in order to simulate the weekly on-peak and off-peak operation of each project powerhouse.

The weekly SP, HLH and LLH value of project energy production was based on hourly energy values provided by BPA. Using the AURORA production cost model, BPA developed hourly energy values for each year in the 50-year hydrologic period of record used by TEAM. These hourly energy values were then used to develop period of record weekly SP, HLH and LLH energy values for input to the COMPARE spreadsheet. To simulate the base case and the three Kaplan repair strategies over the 20-year economic period of analysis for each project and each study scenario, COMPARE combined the TEAM estimates of weekly energy production and the AURORA-based weekly energy values to obtain the corresponding estimates of weekly energy benefits. A more detailed discussion of the project energy production estimates and the corresponding project energy benefit estimates is contained in Appendix D, *Power Benefits*.

4.7. ECONOMICS

The economic analysis involved determining for each study project the net present value (NPV) under the base case and each Kaplan repair strategy. Each NPV was obtained by first determining the present value (PV) of the annual streams of project benefits and project costs to the start of the 20-year economic period of analysis (1 October 2009), and then computing the difference between PV project benefits and PV project costs. The project NPV results were used to obtain the corresponding NPV of each Kaplan repair strategy relative to the base case. These last NPV results were used to identify the best repair strategy for each project from an economic perspective, which is based on the repair strategy that produces the highest NPV (or in some cases the least negative NPV). A sensitivity analysis was performed to determine if the best repair strategy selections are sensitive to changes in economic analysis input assumptions.

The economic analysis analyzed two failure scenarios for John Day (five and eight Kaplan failures over the 20-year economic period of analysis), while each Snake River project analysis assumed one Kaplan failure over the 20-year economic period of analysis. The determination of each project

NPV for the base case and each Kaplan repair strategy was carried out using an Excel spreadsheet. Inputs to the spreadsheet included: (1) annual energy benefits (value of generation) for the base case and each Kaplan repair strategy; (2) annual repair costs for each Kaplan repair strategy (there are no repair costs for the base case); (3) assumed values for the economic period of analysis length and start year; and (4) assumed values for the discount rate (rate of return), energy inflation rate, cost inflation rate, and interest rate for calculating interest during construction costs.

The results of the economic analysis showed that for each study project, Strategy B (failed turbine to become propeller type) produces the highest NPV relative to the base case. In the case of John Day, the highest NPV (or least negative NPV) is achieved under the five Kaplan failures scenario. The main reason Strategy B was determined to be the best repair strategy from an economic perspective for all four projects is that the repair costs for Strategy B are much lower (by a factor of about 10) than the repair costs for Strategy A and Strategy C.

A sensitivity analysis was performed to determine if the best repair strategy selections are sensitive to changes in economic analysis input assumptions. The analysis involved the following four input assumptions: (1) discount rate; (2) energy inflation rate; (3) cost inflation rate; and (4) annual repair costs. The sensitivity analysis varied each of the four input assumptions, one at a time, to see how a change in an assumption would impact the NPV of each Kaplan repair strategy relative to the base case. The sensitivity analysis results indicate that Strategy B remains the best repair strategy from an economic perspective for the four study projects. A more detailed discussion of the economic analysis and sensitivity analysis is contained in Appendix E, *Economics*.

5.0. BASE CASE AND REPAIR STRATEGIES

5.1. BASE CASE

The base case is a scenario needed to economically compare system generation costs for each repair strategy to be evaluated. It assumes no Kaplan units ever fail. System generating benefits and repair costs for each repair strategy will be compared to the system generating benefit of the base case. The strategy which develops the least cost or most benefit will be the best choice from an economic perspective.

5.2. STRATEGY A – FAILED TURBINE TO REMAIN KAPLAN TYPE

Repair Strategy A restores any failed unit to full Kaplan status. Due to the time required to secure funding, prepare contract documents, advertise, and award, it was determined that the most likely repair scenario would involve first restoring the failed unit to operate temporarily as a propeller type during the time it takes to commence with permanent repairs (estimated to be a 24-month period). This is essentially what happened to Lower Monumental unit 1, which is now operating as a propeller unit. Work is currently underway to commence with a Kaplan repair on this unit. Restoring a turbine to Kaplan status would involve replacing key components within the hub (including all the pins), repair any other damaged part or parts and also replacing the blade trunnion bushings with ones coated with non-metallic “lubricant-free” material such as “Karon V” from Kamatics Corporation. This alternative is essentially identical to the repair performed recently on John Day unit 16. It essentially restores the “status quo” and keeps all units as Kaplan type.

For the John Day powerhouse, repairs to five units and to eight units were economically evaluated. These numbers of units were chosen to evaluate the sensitivity of system generation costs to numbers of units which fail. It was not possible or feasible to economically evaluate every possible failure scenario. In addition, the PDT reasoned that after eight failures, a different repair strategy would likely be selected because of economic impacts. For the three Lower Snake River powerhouses, only unit 3 is evaluated. This is because it was determined that both units 1 and 2 would ultimately need to be Kaplan type to satisfy environmental needs.

5.3. STRATEGY B – FAILED TURBINE TO BECOME PROPELLER TYPE

Strategy B involves repairing failed units to be propeller type on an indefinite basis. It should be noted that even though the repair is intended to be for an indefinite period, it would still be possible to revert back to Kaplan operation at some point in the future should the need arise. This strategy would be similar to what was done to Lower Monumental unit 1 except in the manner in which the blades are kept at a fixed angle (i.e., no steel blocks would be used on the exterior of the hub which would extend into the waterway). Pins would be inserted through the blade's palm and into the hub in an area which would not destroy the sealing area or the bushings (see Appendix A for more details). By avoiding compromising the oil seals and bearings with this work, the runners could be repaired to Kaplan status with a conventional repair process. This repair is intended to be permanent – at least until the runner is replaced under a future separate rehabilitation program is commenced which could be 10 to 20 years in the future. Only the units at each plant deemed to be permitted to be permanently operated in fixed blade (propeller) mode would receive this treatment. These are unit 3 at each of the Lower Monumental, Little Goose and Lower Granite powerhouses, and any eight units at John Day powerhouse with the exception of units 1 and 2.

5.4. STRATEGY C – FAILED TURBINE TO REMAIN KAPLAN TYPE WITH IDIQ

Repair Strategy C is similar to Strategy A to restore any failed unit to full Kaplan status except that the unit is not temporarily repaired to a propeller type. The use of an expedited acquisition process or repair by Corps maintenance personnel would be used, which would lessen the out-of-service period. It was assumed that repairs could commence within 6 months of the failure and that it would take 18 months to return the unit to service. This schedule is considered conservative and it is possible that the work could be done more quickly. However, since an expedited acquisition process has not been used before for such significant mechanical work, the total out-of-service duration of 24 months was agreed to by the PDT for the purposes of this study. The internal parts of the blade adjustment mechanism would be Government furnished to reduce the risk of delay.

5.5. GRAPHICAL DEPICTION OF BASE CASE AND STRATEGIES A, B, AND C

Graphical depictions of the repair strategies are shown in Figure 1. All Kaplan turbines with failed blade adjustment mechanisms are first repaired to operate either temporarily or permanently as a propeller turbine. Turbines that must be repaired back to a Kaplan type are later repaired. The repair schedules are shown in Appendix G, *Construction Schedules*. Note that the specific units selected to be repaired to propeller type at John Day were selected at random and do not necessarily indicate which units would actually be repaired in that manner.

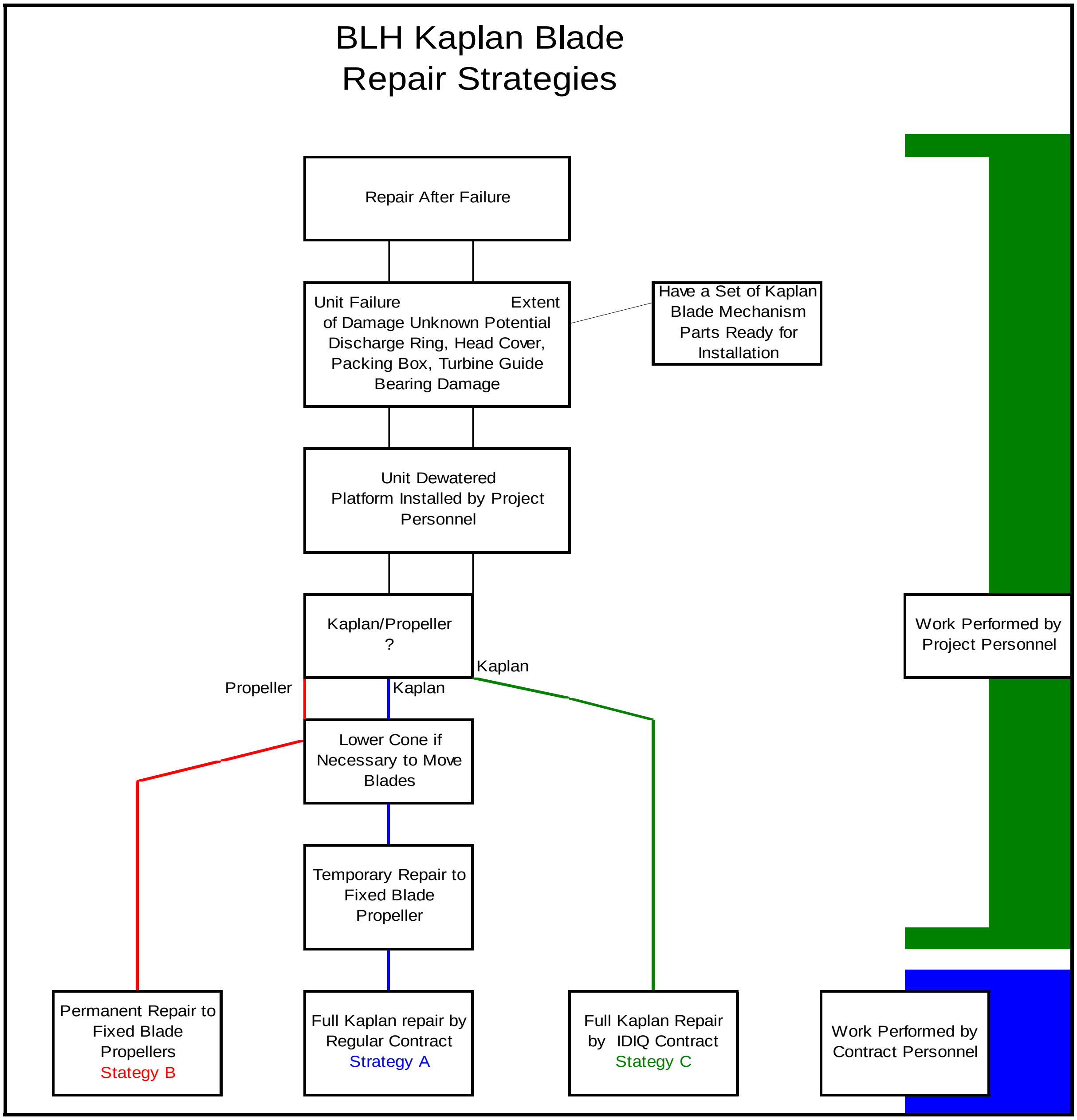
6.0. RECOMMENDED REPAIR STRATEGIES

6.1. JOHN DAY POWERHOUSE

The recommended repair strategy adopted by the PDT for turbines at the John Day powerhouse includes the following:

- If a failure occurs in the blade adjustment mechanism of units 1 or 2, the failed unit should be repaired back to Kaplan type as soon as possible (see Appendix A for more information).
- If a failure occurs in the blade adjustment mechanism of any unit other than units 1 or 2 and there are eight or less turbine units operating in the propeller mode, the failed unit should be repaired to propeller type as soon as possible. The preferred method is to drill, ream, and pin the blades to a 29-degree blade angle and keep the hub full of oil as is normally done (see Appendix A for more information).
- The first turbine permanently repaired to be a propeller type should also have the blade tip gap filler pieces installed (if not already done to a Lower Snake unit). An Index test should then be performed immediately before and after the filler pieces are installed to determine the effect on performance.
- If main unit 5 is turned into a propeller unit permanently, the equipment used to provide station service directly from the generator should be removed from main unit 5 and installed on an adjacent main unit, which is still operating as a Kaplan type.
- An Index test on any unit made a propeller should be performed and FPP and 1% operating criteria revised and adhered to (see Appendix C, *Blade Angle Determination*, for more information).
- A fixed-runner blade angle of 29 degrees appears biologically satisfactory as a temporary or permanent solution (see Appendix C for more information).

Figure 1. BLH Kaplan Blade Repair Strategies



6.2. LOWER SNAKE RIVER POWERHOUSES

The recommended repair strategy adopted by the PDT for the BLH turbines at any of the Lower Snake River powerhouses includes the following:

- If a failure occurs in the blade adjustment mechanism of units 1 or 2, the failed unit should be repaired back to Kaplan type as soon as possible (see Appendix A for more information).
- If a failure occurs in the blade adjustment mechanism of unit 3, it should be permanently repaired to propeller type as soon as possible. The preferred method is to drill, ream, and pin

the blades to a 29-degree blade angle and keep the hub full of oil as is normally done (see Appendix A for more information).

- The first turbine permanently repaired to be a propeller type should also have the blade tip gap filler pieces installed (if not already done to a John Day unit). An Index test should then be performed immediately before and after the filler pieces are installed to determine the effect on performance.
- An Index test on any unit made a propeller should be performed and FPP and 1% operating criteria revised and adhered to (see Appendix C for more information).
- A fixed-runner blade angle of 29 degrees appears biologically satisfactory as a temporary or permanent solution (see Appendix C for more information).

7.0. MODIFY BEFORE FAILURE

This strategy complements the recommended repair strategy to extend the life of the existing blade adjustment mechanism, which will defer repair costs (see Appendix J). The following modifications should be considered for implementation:

- A program to inspect the existing blade linkage components of the 22 remaining 312-inch BLH units on the Lower Snake and Lower Columbia rivers should be considered and then implemented. These units have not been inspected and remain at risk to fail.
- The use of a lubricity-enhancing additive in the hub oil should be considered due to the small cost and high potential to prolong the remaining life of the internal mechanism.
- If a hub is completely disassembled to replace the upper pins or for other reasons, non-metallic coatings with low friction factors on the bushings (such as Karon V) should be a standard repair procedure.
- MIL-L Type 2190 TEP oil should be the oil of choice when new oil is purchased.

8.0. REFERENCES

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Appendix A
Turbine Engineering

Appendix A – Turbine Engineering

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A.1.0. Background and Description of BLH Kaplan Turbines

A.1.1. Background

Construction of the John Day, Lower Monumental, and Little Goose powerhouses[3] was completed in the late 1960s and early 1970s. The Lower Granite powerhouse was completed last in the mid-1970s. A company named Baldwin-Lima-Hamilton[4] (BLH) designed and manufactured 25 identical turbines installed in these powerhouses. Table A-1 shows the various in-service dates for the generating units. They range in age from 37 to 41 years. In the early years of operation at John Day powerhouse, the turbine units began to experience failures of the studs which attached the piston cap to the piston. The major reason for this was due to the relatively short length of the studs and low stud pre-stress. There were lock washers installed between the nuts and the piston cap flange face that were not flattened when the bolts were tightened. Higher than expected blade servomotor (the blade servomotor is a large hydraulic cylinder) pressures were also observed, which sometimes equaled or exceeded the maximum pressure the governor could apply. This led to situations where the blade angle could not be changed. To repair these shortcomings, the turbine units needed to be removed, completely disassembled, and repaired. The repair consisted principally of:

- Replacing the piston cap studs with longer ones.
- Installing a ring on top of the piston cap flange; this essentially doubled the thickness and increased the flange stiffness.
- Replacing all of the bronze blade bushings with a higher lead content bronze.
- Using heavier lubricating oil.

The choice of which lubricating oil to use involved tradeoffs since the same oil needed to be used in the thrust and guide bushings, as well as in the governor. Eventually all of the turbines were repaired. There were additional failures of some links and eye ends but these were infrequent and were not judged to be a design error. It should be noted that units 4, 5, and 6 in the Lower Monumental, Little Goose and Lower Granite powerhouses were installed at a later date and were designed and built by a different company, Allis Chalmers (AC). Although these AC units are the same diameter, speed, and rating as the BLH units, they are not addressed in this report because they are not failing like the BLH units. The same repairs made to the BLH units in the John Day powerhouse were also made to the BLH turbines at Lower Monumental and Little Goose. Because the repair procedures were established prior to installing the Lower Granite turbines, these units were modified by BLH at its factory before being shipped to the site. These early failures of the John Day BLH units had an impact on future hydropower equipment procurements, such as those for the Bonneville 2nd powerhouse. These impacts include:

- Higher lead content bronze blade bushings became standard.
- The blade servomotor, if located in the hub, must be below the blade centerline (to facilitate repairs without having to remove and completely disassemble the turbine).
- Turbines had to be capable of operating with different oils in the governor and hub.
- The governors had to be capable of operating with the heavier oil.

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[3] Only three generating units were installed in the Lower Monumental, Little Goose and Lower Granite powerhouses with skeleton bays for three future units.

[4] BLH no longer is in business. VA Tech now owns all of the engineering data for BLH turbines.

Table A-1. In-service Dates for Turbines at John Day, Little Goose, Lower Granite, and Lower Monumental Powerhouses

In-service Dates for Turbines	
Unit No.	**Date Unit Placed in Service**
John Day Powerhouse	
1	16 July 1968
2	29 August 1968
3	15 October 1968
4	16 November 1968
5	22 January 1969
6	19 February 1969
7	26 March 1969
8	12 May 1969
9	2 July 1969
10	26 August 1969
11	4 February 1970
12	22 April 1970
13	3 November 1970
14	17 December 1970
15	30 September 1971
16	3 November 1971
Little Goose Powerhouse	
1	26 March 1970
2	30 October 1970
3	8 December 1970
Lower Granite Powerhouse	
1	3 April 1975
2	12 May 1975
3	24 June 1975
Lower Monumental Powerhouse	
1	28 May 1969
2	2 September 1969
3	6 January 1970

The turbines at the four powerhouses are capable of producing 212,400 horsepower (155 MW generator output) at their rated head and also operating at net heads which vary from a minimum of 76 feet up to a maximum of 110 feet. Refer to Table A-2 for the minimum, rated, maximum, and average net operating heads for each plant. It should be noted that there is a difference between “net” and “gross” head. Because turbine designers cannot be held responsible for head losses across the trash racks, the unit performance (i.e., power output and efficiency) is based upon the differences between specified forebay and tailwater levels with no accounting for head losses across the trash racks. For design and planning purposes however, an average of one foot of loss across the trash rack is customarily assumed. In reality, the turbines actually operate over a smaller net head range most of the time.

Table A-2. Net Operating Heads for John Day, Little Goose, Lower Granite, and Lower Monumental Powerhouses

Powerhouse	Net Head Operating Range (feet)*			
	Minimum	**Rated**	**Maximum**	**Average****
John Day	83.5	94	110	101
Lower Monumental	87	94	100	97
Little Goose	90.5	93	98	95
Lower Granite	76	93	105	99

*The minimum, rated and maximum net heads listed are the original turbine contract performance requirements.
**These values are the average gross head at the minimum operating pool (MOP) for the last 10 years minus 1 foot for the trash rack loss (see Appendix C).

John Day Dam's gross head (forebay minus tailwater) normally varies from 99 feet to 104 feet. Four generating units (11, 12, 13 and 14) are normally operated as synchronous condensers during the months of June through October. Synchronous condensing means the generators are operated as motors – spinning the turbine runner in air. This provides for a more stable electric transmission system. The generating units in the Lower Snake River powerhouses have not been modified to be able to operate as synchronous condensers. In January 2009, John Day unit 14 was tested (i.e., transitioned from generating mode into condensing mode) with the blades locked at 29 degrees in an effort to determine if it would behave normally (i.e., like it does when it operates as a Kaplan unit). It should be noted that when a Kaplan unit is transitioned to condensing operation, the blades are normally in the flat position (16 degrees). When transitioning, the unit continues to spin at 90 revolutions per minute (rpm) while flow of water through the unit is stopped and the water which is trapped in the runner chamber is depressed to a level below the spinning turbine blades (using compressed air) in approximately 10 seconds. The test results showed that it behaved normally during condensing when the blades were held at 29 degrees. There is no reason to require full Kaplan repairs to the condensing units should a failure in their blade adjustment mechanism occur More information is located in Appendix I, *Pertinent Documentation* (see Volume II).

The synchronous speed of all these units is 90 rpm. The generators for all but Lower Granite's units were manufactured by General Electric and are rated at 142,105 KVA with a 115% continuous duty overload capability. At their design power factor of 0.95, they are capable of continuous output of 155.25 MW. Lower Granite's three BLH turbines are connected to generators manufactured by Westinghouse. They have ratings identical to the General Electric units.

A.1.2. Description of Blade Adjustment Mechanism Design

Kaplan turbines have the capability of changing the pitch of their blades while operating. This is accomplished by the governor increasing the oil pressure to one side of a large hydraulic piston (called the blade servo) while reducing the pressure on the other side until the force exerted by the piston overcomes the friction in the adjustment mechanism and blade torques (applied by water flowing over the blades). Governor oil pressure in older units was typically 300 pounds per square inch (psi). Later models typically used 500 psi and the newest units are 1,000 psi. This is why the old and new turbines at Bonneville have 300 psi and 1,000 psi governors, respectively. At John Day and units 1, 2 and 3 at the Lower Snake River plants, the governors are 550 psi.

Oil is routed to the blade servo cylinder through a set of concentric oil pipes located in the center of the generator and turbine shafts. The *oil head*, located on top of the generator, feeds the oil to the spinning oil pipes. There are three nested oil pipes. The innermost one (2-inch inside diameter) runs from the turbine hub to a reservoir of oil at the top of the oil head and simply applies a static pressure to the hub via the weight of the column of oil. This chamber is called the static oil head. This helps pressurize the hub to minimize the influx of water into the hub and assures all hub bearings remain fully flooded with oil. The middle pipe (5-inch inside diameter) is connected to the piston cap, which is bolted to the top of the piston. It supplies pressurized oil to the underside of the piston (through a hole drilled through the piston) to drive the blades flat. The outer oil pipe (8-inch inside diameter) is connected to a *pipe nut* which is attached to the lower end of the turbine shaft. It provides pressurized oil to the top of the piston to drive the blades steep. Some turbine designs locate the blade servo cylinder in the shaft (e.g., The Dalles) and some are located in the hub. Both designs work well and the servo location is left up to the turbine manufacturer.

A *blade servomotor rod* is connected to the blade servo piston at its upper end and to a *crosshead* at its lower end. The crosshead has six arms with *eye ends* attached to their ends. Each eye end has a *link pin* installed in it which are also attached to the lower ends of two *link plates*. The upper end of the link plates are pinned to the *blade lever* (sometimes called a *rocker arm*) with another link pin. The blade lever is keyed to the turbine blade trunnion. The up and down motion of the servo piston translates to rotation of the blade through this mechanism. Typically, the blades can rotate through an angle of 16 degrees (from 16 to 32 degrees measured at the blade's tip) of motion. Turbine designers purposefully strive to have water forces on the blades tend to drive them to tilt steeper in the event of a runaway (Photo A-1). This is because in the event of a runaway condition (i.e., loss of governor control and the generator becomes disconnected from the line), the resulting overspeed is minimized at steeper blade angles. Photo A-1 shows John Day unit 16 where one blade's mechanism failed (this blade is at a flatter angle than the others).

Photo A-1. Blade with Broken Linkage

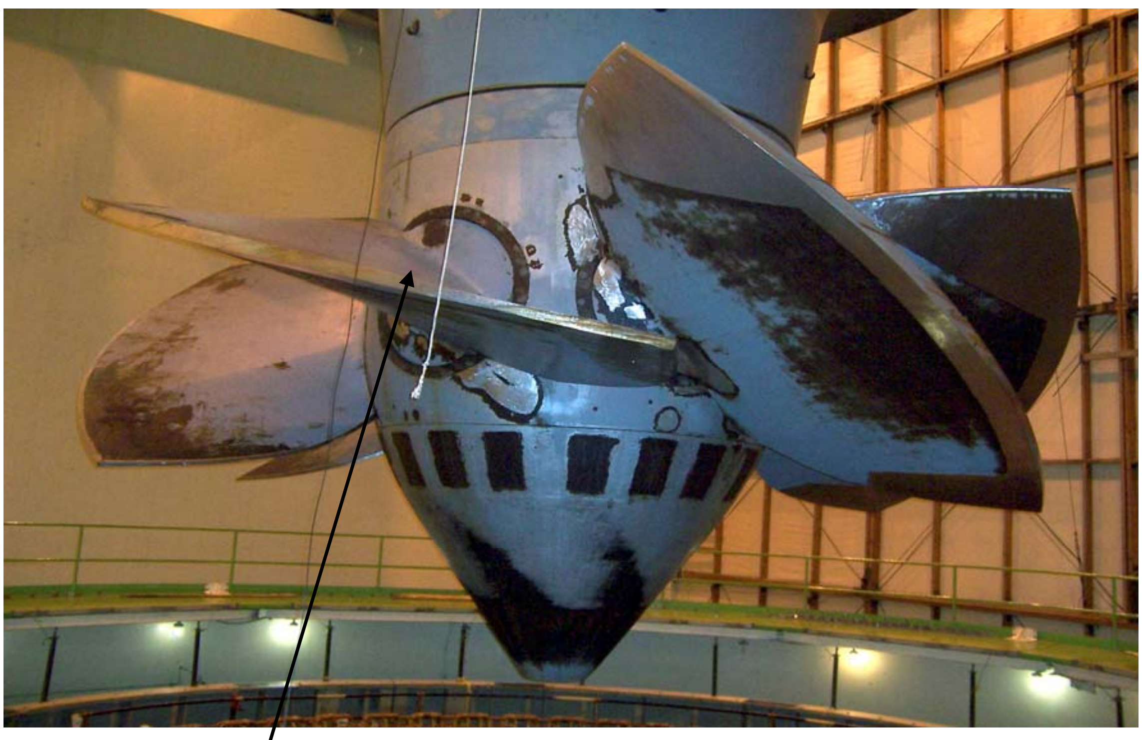


Photo showing John Day unit 16 as it is being removed from the water passage for repair. The arrow points to the blade with the broken linkage.

The clearance between the turbine runner's blade tips and the steel *discharge ring* is typically 3/8 inch. The discharge ring was machined in the shop to a cylindrical shape above the centerline of the blade and spherical below the blade's centerline for a short distance. Below this, the ring's diameter begins to increase to fit the top of the *draft tube*. The area where the water passage changes from converging to diverging is called the *throat*. The throat is the smallest area where the flowing water passes and thus is where the water velocity is the highest. The blade tips were similarly machined (to the discharge ring) at the factory (e.g., cylindrical above and spherical below their center) *while they were held in their flat position*. Due to the geometry of the discharge ring and blades, gaps exist between the blade and hub and between the blade tips and discharge ring as the blade angle changes. Gaps are large at the blade's tips at steep blade angles and smallest at flat angles. The reverse is true for gaps between the blades and hub. If a blade's angle exceeds its maximum design angle (as would happen if a link pin broke), the blade's tip would rub against the discharge ring. Also, the resulting hydraulic imbalance can cause the blade 180 degrees opposite to it to also rub the discharge ring.

A *runaway* can occur when the main circuit breaker opens unexpectedly and the flow of water through the turbine cannot be halted. This causes the speed of the generating unit to quickly accelerate. The maximum runaway speed occurs with the blades in the flat position and presents the most risk of damage to the turbine or generator.

The governor "knows" the blade's angle by sensing the vertical position of the inner oil pipe (it moves up and down with the servo piston) as the blade angle changes. The governor continues to supply more oil to the servo until the correct blade angle has been achieved. In actuality, the movement of the blade is jerky due to its slow motion, accumulated slack due to machining clearances, and the elasticity of the parts themselves. All bushings in the adjustment mechanism are experiencing almost metal-to-metal contact on a molecular level (called boundary layer lubrication) when the blade's angle is changed. Because the static coefficient of friction is always larger than the kinetic coefficient of friction, and there is flexibility in all parts, the blades move in a series of small motions as the applied forces build to overcome friction and fall (after there is some motion). There is strong evidence (see Appendix J) to support the notion that the blades themselves do not move together. The net result is that the parts are subjected to high numbers of load cycles and the loads, especially on the eye ends, links, link pins and blade lever, are larger than the original design. This is a perfect recipe for parts to fail by fatigue. Prior failures, research work, and ultrasonic testing of link pins have shown that this is how these parts fail.

A.1.3. Failures and Ultrasonic Testing

Link pin failures have occurred in turbines at the Lower Monumental (unit 1) and John Day (unit 16) powerhouses in the last 4 years. In both units, the link pins failed due to fatigue. Fatigue is a process where a crack is initiated and slowly enlarges over time until the un-cracked area is too small to support the applied load and fails abruptly. The crack initiation site in the BLH units seems to have a preference for the bottom inside part of the lower pins.

An overall summary of the repair history of the 25 BLH units is provided in the Table A-3, which shows the particular unit, the work performed, and the year in which the work occurred.

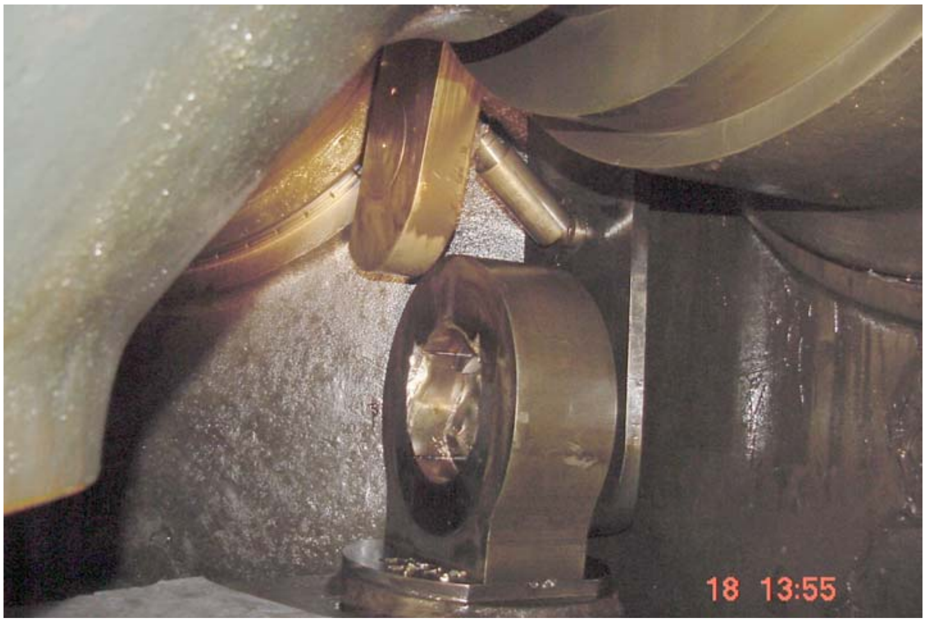
Table A-3. BLH Turbine Modifications and Repair History

Main Unit Number	Modification or Repair Item																																		
	Unit Online	Inner Blade Bushing, New	Outer Blade Bushing, New	Blade Link Plates, OE, Keyway Mod	Blade Link Plates, New, Keyway Mod	Blade Link Pins, OE, Keyway Mod, 3/8 Rad	Blade Link Pins, New, Keyway Mod	Blade Packing, New	Wicket Gate Bushings, New	Wicket Gate Seals, New	Crosshead Eyebolts, OE, 3/8" rad.	Crosshead Eyebolts, New, 3/8" rad.	Crosshead Eyebolts NDT (removed)	Crosshead Eyebolt Spacers, New	Piston Cap, New	Piston Cap, Refurbished	Piston Cap Bolts, New	Piston Cap Ring, New	Piston Rings, New	Upper Piston Rod Nut, New OE Type	U&L Piston Rod Nuts, New Supernuts	Oil Head Pipe Guide, Mod	Link Pin Keepers	Hub Cavitation Repair	Blade Cavitation Repair	Servo Rebuilt	Piston Cap Bolt Repair	Broken Eye End	Blade Link Failed	Runner Bushing Testing, Oil Pressures	Wicket Gate Cracks	Stud Stretcher Fabricated	Lower Link Pin Fatigue Failure	Linkage Replacement, Greaseless Bushings	
1	**68**	**86**	**86**	**86**		**86**		**86**	**86**	**86**	**86**		**86**	**86**			**86**	**86**													**71**				
2	**68**	**87**	**87**		**87**	**87**		**87**	**X**	**X**	**?**		**87**	**X**		**76**	**76**	**76**				**76**	**76**				**76**					**87**			Contracts: 76-C-0069, other work in '87?
3	**68**	**90**	**90**	**90**		**90**		**90**	**90**	**90**	**?**			**90**			**90**	**90**																	
4	**68**	**80**	**80**	**80**		**80**		**80**	**80**	**80**	**80**			**80**			**80**	**80**		**80**		**76**	**76**				**81**								Contracts: 76-C-0069, 80-C-0049
5	**69**			**81**			**81**																				**75**	**75**	**81**						Overhaul performed in place (upper pins?)
6	**69**	**87**	**87**	**87**		**87**		**87**	**87**	**87**	**87**	**87**	**88**	**87**		**87**	**87**	**87**	**87**																One new crosshead eyebolt & spacer (another spare?)
7	**69**					**85**							**85**																						
8	**69**	**88**	**88**	**88**		**88**		**88**	**88**	**88**	**88**		**88**	**88**			**88**	**?**												**74**					
9	**69**	**85**	**85**	**85**		**85**		**85**	**85**	**85**	**85**			**85**		**?**	**85**	**85**																	
10	**69**	**--**	**83**	**83**		**83**		**83**	**83**	**83**	**?**		**83**	**83**		**?**	**83**	**83**						**83**	**83**		**74**				**71**				Unit 10 1st to receive bushing, link, eye end mods
11	**70**	**89**	**89**	**89**		**89**		**89**	**89**	**89**	**?**		**89**	**?**		**?**	**89**	**89**								**89**	**76**				**71**				
12	**70**	**81**	**81**	**81**		**81**		**81**	**81**	**81**	**81**			**81**		**81**	**81**	**?**		**81**							**82**				**71**				Contracts: 80-C-0132
13	**70**	**84**	**84**	**84**		**84**		**84**	**84**	**84**	**?**			**?**		**?**	**84**	**?**													**71**				
14	**70**							**74**	**74**	**74**						**74**	**74**							**74**	**74**	**74**	**74**			**74**	**71**				
15	**71**	**92**	**92**	**92**		**92**		**92**	**92**	**92**	**92**			**92**		**?**	**92**	**92**				**76**	**76**				**76**								Contracts: 76-C-0069
16	**71**	**84**	**84**	**84**		**84**		**84**	**84**	**84**	**84**			**83**		**?**	**84**										**83**						**06**	**07**	
1	**69**	**93**	**93**	**93**		**93**		**93**	**93**	**93**	**93**			**93**			**93**	**93**	**93**			**93**		**93**	**93**										
2	**69**	**94**	**94**	**94**		**94**		**94**	**94**	**94**	**94**			**94**			**94**	**94**	**94**			**94**		**94**	**94**										
3	**70**	**93**	**93**	**93**		**93**		**93**	**93**	**93**	**93**			**93**			**93**	**93**	**93**			**93**		**93**	**93**										Contract: 92-C-0030
1	**70**	**92**	**92**	**92**		**92**		**92**	**92**	**92**	**92**			**92**			**92**	**92**	**92**			**92**		**92**	**92**										Contract: 91-C-0046
2	**70**	**93**	**93**	**93**		**93**		**93**	**93**	**93**	**93**			**93**			**93**	**93**	**93**			**93**		**93**	**93**										Contract: 92-C-0047
3	**70**	**94**	**94**	**94**		**94**		**94**	**94**	**94**	**94**			**94**			**94**	**94**	**94**			**94**		**94**	**94**										Contract: 92-C-0047
1	**75**							**74**	**74**															**06**	**06**										
2	**75**	**07**	**07**	**07**	**07**		**07**	**74**	**74**		**07**			**07**			**07**		**07**					**07**	**07**			**02**	**02**				**02**		Contract: 03-C-0023
3	**75**							**74**	**74**															**08**	**08**										

A.1.3.1. Lower Monumental Unit 1 Failure

There have been many failures associated with the BLH units over the years. Prior to 3 April 2005, the only major blade operating linkage component that had not failed besides the blade levers and the crosshead was the link pins. On 3 April 2005, Lower Monumental project personnel noticed significant vibration while operating unit 1 requiring it to be taken out of service. Investigations the following day confirmed the unit had a significant vibration problem and as the unit was loaded the vibration increased. The unit was shut down to investigate the cause of the apparent mechanical imbalance. Photo A-2 was taken inside the unit 1 runner hub showing the broken linkage for Blade D. The inside part of the lower pin is missing and the link bolt is bent. The inside link is hanging from the blade lever while the pin for the outside link is broken at the blade lever and the link is resting on the broken pin in the eye end. It is thought that the lower pin failed first, which then caused the upper pin to fail because one side had to support twice the load.

Photo A-2. Broken Linkage for Blade D, Lower Monumental Unit 1



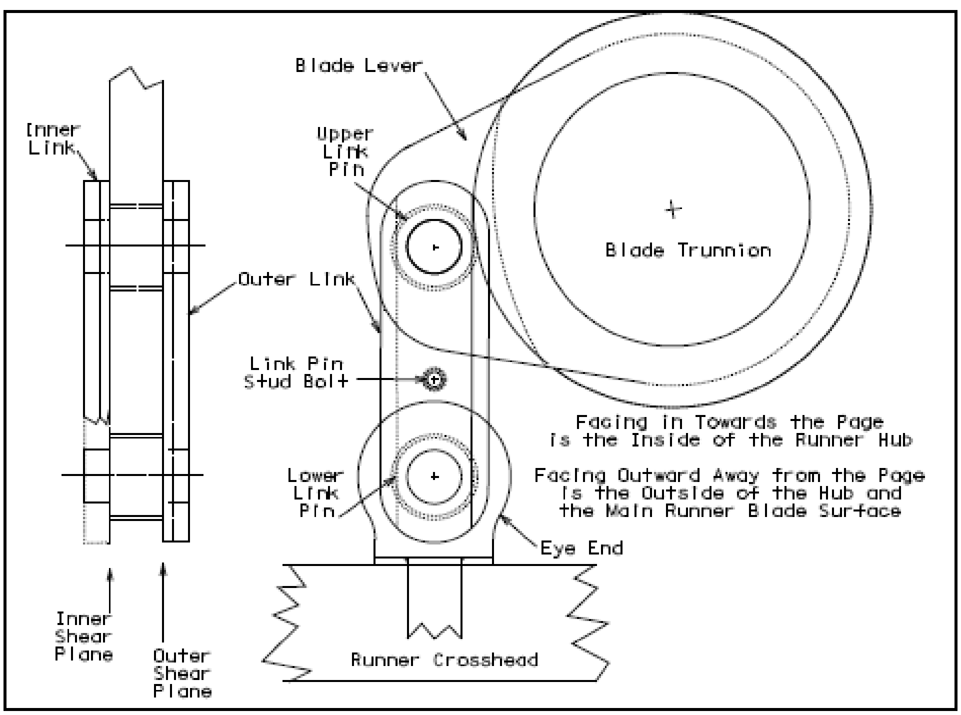
The unit was dewatered, a platform installed and the unit inspected. One blade was in a flat position and was out of synchronization (i.e., not at the same angle) with the other five blades. The blade had also contacted and damaged the discharge ring as well as its own tip area. The turbine runner cone was lowered to inspect the operating mechanism. The inspection revealed both the upper and lower link pins at the interface between the 5½-inch diameter section and the 8-inch diameter section on one blade linkage mechanism had failed.

Photo A-3 shows Lower Monumental unit 1 lower pin after removal from the runner hub. The two broken pieces are put together to show how the pin fractured. The upper link pin failed on the outside shear plane between the pin journal and the keyed portion of the pin. This is also the change of radius between the two segments and the location of the 1/16-inch undercut radius. Investigation of the curvature of the “beach marks” indicated that a fatigue crack initiated from the top of the pin and progressed through the material toward the bottom where it finally failed in a typical tensile break. Approximately 90% to 95% of the cross-sectional area of the pin had fatigued before the pin failed by a tensile break.

The lower link pin failed on the inside shear plane between the pin journal and the keyed portion of the pin. Again, this is the change of radius between the two segments and the location of the 1/16-inch undercut radius. Figure A-1 shows the blade linkage mechanism with the inner and outer shear planes where the failures occurred.

Photo A-3. Lower Pin After Removal from Runner Hub, Lower Monumental Unit 1

Figure A-1. Blade Linkage Mechanism Showing the Inner and Outer Shear Planes where Failures Occurred

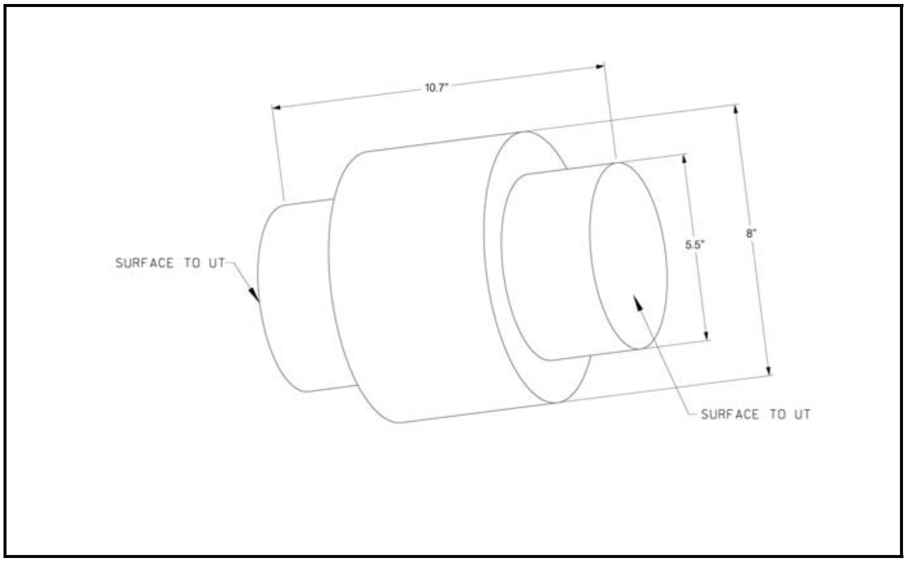


The curvature of the "beach marks" indicated that the fatigue cracks initiated from both the top and the bottom of the pin and progressed toward the upper center where again the pin failed in a tensile break. The fatigue initiating from the lower end covered a much larger cross-sectional area than the fatigue crack initiating from the upper end. About 80% of the cross-section of the pin had fatigued failed before the pin actually failed by a tensile break.

Subsequent Investigations

Mountain Inspection Services was contracted to inspect the remaining 10-blade link pins and the remaining 5 stud bolts in-place. The inspection method employed was the ultrasonic non-destructive test method (UT). The pins were inspected longitudinally from each end (see Figure A-2) and the stud bolt also was inspected from the nut end longitudinally through the stud.

Figure A-2. Link Pin Showing the UT Inspected Surfaces



Summary of Findings

- **Blade A.** Lower inside shear plane had fatigued in a cone shape from the central oil hole outward. About 20% of the cross-section had failed. There was no relevant indication of failure on the lower outside of the pin. The upper pin and the stud bolt showed no relevant indication of failure.
- **Blade B.** The upper and lower pin and stud bolt showed no relevant indication of failure.
- **Blade C.** Lower inside of the pin had fatigued from the inside out initiating at the central oil hole. The crack was not on the shear plane but was about 1 inch inside the journal portion of the pin. About 10% of the cross-section had failed. The outside of the lower pin fatigued from both the top and bottom and had only progressed about ½-inch on each side. About 10% of the cross-section had failed. The upper pin and stud bolt showed no relevant indication of failure.
- **Blade D.** The failed linkage.
- **Blade E.** The lower inside shear plane of the pin had fatigued from the bottom and had progressed about 3/4-inch. About 10% of the cross-section had failed. The upper pin and the stud bolt showed no relevant indication of failure.

- **Blade F.** The lower inside shear plane of this pin had fatigued from top to bottom. About 90% or more of the cross-section had failed. If Blade D had not failed this one was well on the way to failing. The lower outside showed no relevant indications. The upper pin and the stud bolt showed no relevant indication of failure.

This testing showed that four of the five remaining lower pinned connections were in the early stages of failure. The failure of Blade F was imminent had Blade D not failed. A surprising finding was that the inner 3/8-inch oil supply hole appeared to have initiated two of the lower pin cracks on the other blades (Blades A and C). The stud bolts and upper pins on all five of the remaining linkages showed no indications of failure.

A.1.3.2. Lower Granite Unit 2 Failure

In 1999, a link from the blade linkage of unit 2 at Lower Granite failed. Project personnel performed an *in situ* repair and had the unit back in service within about 7 months. About 2 years later in 2001, the eye end from the same unit in the same blade linkage failed. The failure was probably due to damage from the first failure. An interim repair was performed on the unit in anticipation of a complete repair at a later date. A complete repair was performed in 2006. The runner was placed in the erection area and disassembled. The inspection service of Oxarc was used to perform a UT inspection of the link pins in October of 2006. Their finding was that there were no relevant indications in the link pins.

A.1.3.3. John Day Unit 16 Failure

On 20 April 2006, they Corps' Hydraulic Design Center received word from the John Day project that unit 16 had been taken out of service due to excessive unit vibration. After dewatering the unit visual inspection indicated that one of the blade linkages appeared broken because one blade was not in synchronization with the other five blades. The operations staff decided to perform a complete repair of the unit so it was not deemed necessary to drop the cone and inspect the runner blade linkage. A few weeks later, with the unit disassembled and the runner apart, the visual inspections showed the failure was a result of a shear failure of one of the lower link pins. The pin broke on the inside shear plane similar to the failure at Lower Monumental.

A more detailed non-destructive testing inspection by Carlson Testing concluded that the other pins had no relevant indications. This was an unexpected finding since so many of the Lower Monumental pins showed significant signs of fatigue cracking. Photo A-4 shows inside the runner hub of John Day unit 16 showing the broken linkage. The inside part of the lower pin is missing and the link bolt is bent similar to the failure mechanism of unit 1 at Lower Monumental. Photo A-5 shows the broken inside end of the link pin at John Day.

Photo A-4. Inside of the Runner Hub Showing Broken Linkage, John Day Unit 16

Photo A-5. Broken Inside End of the Link Pin, John Day

A.1.3.4. <u>Little Goose Inspection</u>

On 1 November 2005, Mountain Inspection, the same company that performed the inspection work on unit 1 at Lower Monumental, performed the same inspection on unit 1 at Little Goose Dam. Because so many of the link pins at Lower Monumental unit 1 were failing, it was thought that other units in the same family could be prone to this failure mechanism. Since Little Goose was going to perform a preventative maintenance on unit 1, it was an opportunity to check the link pins on another unit of this family. The six upper and six lower pins were ultrasonically tested. No significant indications were found. The whole process took about 2-3 weeks.

A.1.3.5. Lower Granite Inspection

In August 2007, Lower Granite personnel performed a similar inspection on unit 3. The project forces lowered the runner cone and contracted a non-destructive testing (NDT) inspection company to inspect the pins ultrasonically. No deficiencies were found. Other linkage parts were not inspected. The work was performed under a scheduled outage to replace blade seals.

A.2.0. Performance of BLH and AC Turbines in Fixed and Adjustable Blade (Kaplan) Modes

Performance data for all generating units at the projects being studied is needed to determine economic benefits accrued as the flow of the river water passes through them. The output of the generators depends on many things including the gross head the plant is subjected to, the flow rate of the water passing through the turbines, if the turbine is operating in Kaplan or propeller mode, if fish screens are installed in the unit's intake and, if installed, the type of screen used. There are two fish screen types: submerged traveling screen (STS) and extended submerged bar screen (ESBS). An ESBS is larger than an STS and therefore, causes more head loss as water flows through and around it. Since the units of a family (BLH or AC) are identical, their performance will be modeled based on their family rather than the project. Therefore, all BLH units will be modeled together as a group with the same performance. All AC units will be modeled together as a group with the same performance. The following performance models were developed:

a. BLH Kaplan units with no screens installed: John Day units 1-16, Lower Monumental units 1-3, Little Goose units 1-3, and Lower Granite units 1-3.
b. BLH Kaplan units with STS installed: John Day units 1-16 and Lower Monumental units 1-3.
c. BLH Kaplan units with ESBS installed: Little Goose units 1-3 and Lower Granite units 1-3.
d. BLH fixed blade propeller units with no screens installed: John Day units 1-16, Lower Monumental units 1-3, Little Goose units 1-3, and Lower Granite units 1-3.
e. BLH fixed blade propeller units with STS installed: John Day units 1-16 and Lower Monumental units 1-3.
f. BLH fixed blade propeller units with ESBS installed: Little Goose units 1-3 and Lower Granite units 1-3.
g. AC Kaplan units with no screens installed: Lower Monumental units 4-6, Little Goose units 4-6 and Lower Granite units 4-6.
h. AC Kaplan units with STS installed: Lower Monumental units 4-6.
i. AC Kaplan units with ESBS installed: Little Goose units 4-6 and Lower Granite units 4-6.

Provided below is an explanation of the terminology used in the performance tables and graphs that follow.

Explanation of the Table Columns

1. Prototype Net Head – the gross head (forebay elevation – tailwater elevation) minus head losses.
2. Proto Hp – the output of the turbine in horsepower.
3. Prototype Efficiency – the efficiency of a turbine in converting water potential energy into mechanical work.
4. Proto Q – the power discharge that passes through the turbine water passage.
5. Head Loss – the difference between the gross head and the net head.

6. Generator Eff. – the efficiency of the generator in converting mechanical work to electrical energy.
7. Unit Efficiency – the turbine efficiency x the generator efficiency or the overall efficiency of converting water potential energy to electrical energy or "water wire" efficiency.
8. Generator Output – The electrical output of the generator in megawatts.

Explanation of the Measurement Points

1. Minimum Power – the minimum point at which the unit can continuously operate without significant operational damage.
2. Lower 1% (and 2%) – the power output below the best operating point (BOP) and 1% (2%) below the peak efficiency
3. Best Gate – the wicket gate opening at which the turbine is operating at its peak efficiency.
4. Upper 1% (2%) – the power output above the best operating point and 1% (2%) below the peak efficiency.
5. Maximum Output – the maximum output of the turbine or generator (the tables that follow actually show values that are outputs at full wicket gate opening, in which the higher heads is above the turbine/generator limits; they are used to develop polynomials for the energy calculations and will be limited by the turbine/generator limit during those calculations).

Table A-4. Performance with No Screens for BLH Units 1-3 at Lower Snake and Units 1-16 at John Day

Minimum Power (@ 80%eff)								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	75,666	80.0	9,803	0.2	85.2	98.4%	78.71%	55.5
90	75,247	80.0	9,207	0.2	90.2	98.4%	78.69%	55.2
95	76,803	80.0	8,903	0.2	95.2	98.4%	78.68%	56.3
100	82,298	80.0	9,063	0.2	100.2	98.4%	78.69%	60.4
105	86,455	80.0	9,068	0.2	105.2	98.4%	78.69%	63.4
110	88,218	80.0	8,832	0.2	110.2	98.4%	78.68%	64.7
Lower 1%								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	97,271	85.7	11,764	0.3	85.3	98.5%	84.39%	71.4
90	104,260	86.4	11,812	0.3	90.3	98.5%	85.08%	76.6
95	109,340	86.6	11,709	0.3	95.3	98.5%	85.27%	80.3
100	116,072	87.2	11,727	0.3	100.3	98.5%	85.87%	85.2
105	122,720	87.4	11,781	0.3	105.3	98.5%	86.06%	90.1
110	126,171	87.6	11,536	0.3	110.3	98.5%	86.25%	92.6
Best Gate								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	145,349	86.7	17,376	0.4	85.4	98.7%	85.57%	107.0
90	154,590	87.4	17,314	0.4	90.4	98.7%	86.26%	113.8
95	159,472	87.6	16,882	0.4	95.4	98.7%	86.44%	117.3
100	167,810	88.2	16,762	0.4	100.4	98.7%	87.03%	123.5
105	175,800	88.4	16,686	0.4	105.4	98.7%	87.22%	129.3
110	188,506	88.6	17,040	0.4	110.4	98.7%	87.43%	138.7
Upper 1%								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	167,672	85.7	20,279	0.5	85.5	98.8%	84.68%	123.5
90	175,709	86.4	19,907	0.5	90.5	98.8%	85.36%	129.4
95	198,115	86.6	21,215	0.5	95.5	98.8%	85.60%	146.0
100	196,810	87.2	19,884	0.5	100.5	98.8%	86.15%	145.0
105	213,511	87.4	20,497	0.5	105.5	98.8%	86.37%	157.3
110	228,942	87.6	20,932	0.5	110.5	98.8%	86.58%	168.7
Maximum Output (Near Full Gate - about 96%)								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	183,701	82.0	23,220	0.6	85.56	98.9%	81.12%	135.5
90	200,146	82.5	23,748	0.6	90.57	98.9%	81.63%	147.7
95	217,055	83.0	24,252	0.6	95.58	99.0%	82.15%	160.2
100	234,414	83.5	24,733	0.6	100.59	99.0%	82.66%	173.0
105	252,213	84.0	25,193	0.6	105.60	99.0%	83.17%	186.2
110	270,441	85.0	25,482	0.6	110.61	99.0%	84.17%	199.7

Table A-5. STS Performance for BLH Units 1-3 at Lower Snake and Units 1-16 at John Day

Minimum Power (@ 80%eff)								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	78,938	80.0	10,227	0.2	85.2	98.4%	78.73%	57.9
90	78,501	80.0	9,605	0.2	90.2	98.4%	78.71%	57.6
95	80,125	80.0	9,288	0.2	95.2	98.4%	78.70%	58.8
100	85,857	80.0	9,455	0.2	100.2	98.4%	78.70%	63.0
105	90,194	80.0	9,460	0.2	105.2	98.4%	78.70%	66.2
110	92,033	80.0	9,214	0.2	110.2	98.4%	78.69%	67.5
Lower 1%								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	96,246	84.7	11,779	0.3	85.3	98.5%	83.39%	70.7
90	103,161	85.4	11,828	0.3	90.3	98.5%	84.08%	75.8
95	108,188	85.6	11,724	0.3	95.3	98.5%	84.27%	79.4
100	114,849	86.2	11,742	0.3	100.3	98.5%	84.85%	84.3
105	121,427	86.4	11,796	0.3	105.3	98.5%	85.05%	89.2
110	124,841	86.6	11,550	0.3	110.3	98.5%	85.23%	91.7
Best Gate								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	140,220	85.7	16,961	0.4	85.4	98.7%	84.56%	103.2
90	149,136	86.4	16,901	0.4	90.4	98.7%	85.24%	109.7
95	153,845	86.6	16,479	0.4	95.4	98.7%	85.42%	113.2
100	161,889	87.2	16,362	0.4	100.4	98.7%	86.00%	119.1
105	169,597	87.4	16,288	0.4	105.4	98.7%	86.19%	124.8
110	181,855	87.6	16,633	0.4	110.4	98.7%	86.40%	133.8
Upper 1%								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	172,908	84.7	21,162	0.5	85.5	98.8%	83.71%	127.4
90	181,196	85.4	20,774	0.5	90.5	98.8%	84.38%	133.5
95	204,301	85.6	22,139	0.5	95.5	98.9%	84.62%	150.6
100	202,956	86.2	20,750	0.5	100.5	98.8%	85.16%	149.6
105	220,179	86.4	21,390	0.5	105.5	98.9%	85.38%	162.3
110	236,091	86.6	21,843	0.5	110.5	98.9%	85.59%	174.1
Maximum Output (Near Full Gate - about 96%)								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	185,960	81.0	23,799	0.6	85.57	99.0%	80.14%	137.2
90	202,607	81.5	24,340	0.6	90.58	99.0%	80.65%	149.5
95	219,723	82.0	24,857	0.6	95.60	99.0%	81.15%	162.2
100	237,296	82.5	25,350	0.6	100.61	99.0%	81.66%	175.2
105	255,314	83.0	25,821	0.6	105.62	99.0%	82.16%	188.5
110	273,766	84.0	26,118	0.6	110.63	99.0%	83.15%	202.2

Table A-6. ESBS Performance for BLH Units 1-3 at Lower Snake and Units 1-16 at John Day

Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
Minimum Power (@ 80%eff)								
85	82,288	80.0	10,661	0.3	85.3	98.4%	78.74%	60.4
90	81,832	80.0	10,013	0.2	90.2	98.4%	78.72%	60.0
95	83,525	80.0	9,682	0.2	95.2	98.4%	78.71%	61.3
100	89,500	80.0	9,856	0.2	100.2	98.4%	78.72%	65.7
105	94,021	80.0	9,861	0.2	105.2	98.4%	78.72%	69.0
110	95,938	80.0	9,605	0.2	110.2	98.4%	78.71%	70.4
Lower 1%								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	95,325	83.6	11,816	0.3	85.3	98.5%	82.34%	70.0
90	102,174	84.3	11,864	0.3	90.3	98.5%	83.01%	75.0
95	107,153	84.5	11,761	0.3	95.3	98.5%	83.20%	78.7
100	113,750	85.1	11,779	0.3	100.3	98.5%	83.78%	83.5
105	120,265	85.3	11,833	0.3	105.3	98.5%	83.97%	88.3
110	123,647	85.5	11,586	0.3	110.3	98.5%	84.16%	90.8
Best Gate								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	118,663	84.6	14,535	0.3	85.3	98.6%	83.42%	87.2
90	126,207	85.3	14,483	0.3	90.3	98.6%	84.09%	92.8
95	130,193	85.5	14,122	0.3	95.3	98.6%	84.27%	95.7
100	137,000	86.1	14,021	0.3	100.3	98.6%	84.84%	100.7
105	143,523	86.3	13,958	0.3	105.3	98.6%	85.03%	105.5
110	153,896	86.5	14,254	0.3	110.3	98.6%	85.23%	113.1
Upper 1%								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	148,771	83.6	18,441	0.4	85.4	98.7%	82.56%	109.5
90	155,903	84.3	18,103	0.4	90.4	98.7%	83.22%	114.8
95	175,783	84.5	19,293	0.5	95.5	98.8%	83.46%	129.5
100	174,625	85.1	18,082	0.4	100.4	98.7%	83.99%	128.6
105	189,443	85.3	18,640	0.4	105.4	98.7%	84.21%	139.5
110	203,135	85.5	19,035	0.5	110.5	98.8%	84.41%	149.6
Maximum Output (Near Full Gate - about 96%)								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	165,744	79.9	21,496	0.5	85.52	98.9%	79.01%	122.2
90	180,582	80.4	21,985	0.5	90.53	98.9%	79.50%	133.2
95	195,837	80.9	22,451	0.5	95.54	98.9%	80.00%	144.4
100	211,500	81.4	22,896	0.5	100.55	98.9%	80.50%	156.0
105	227,559	81.9	23,322	0.6	105.56	98.9%	80.99%	167.9
110	244,005	82.8	23,590	0.6	110.57	98.9%	81.97%	180.0

Figure A-3. BLH Best Operating Point and Maximum Power Efficiency vs. Head

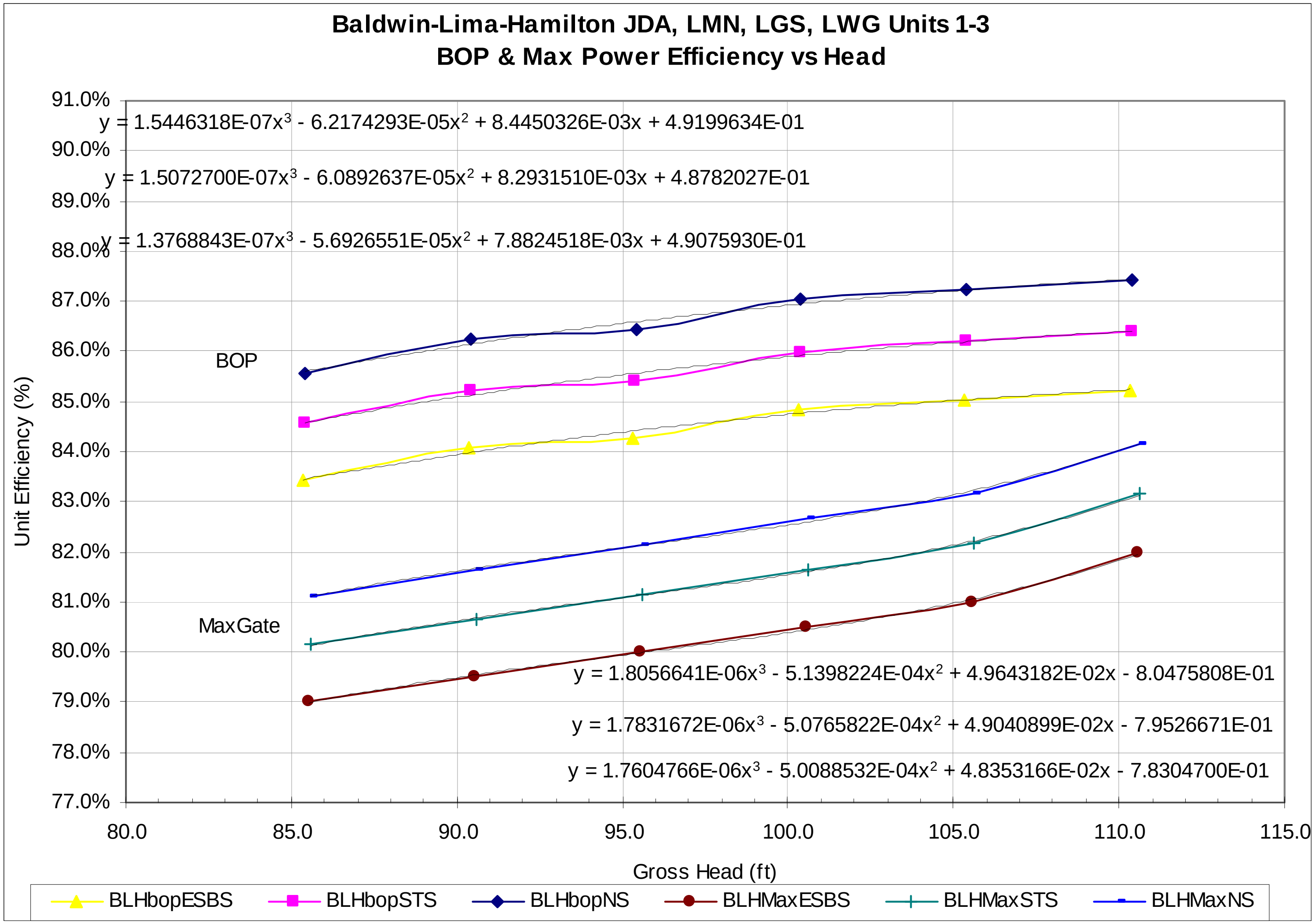


Figure A-4. BLH Best Operating Point and Maximum Power vs. Head

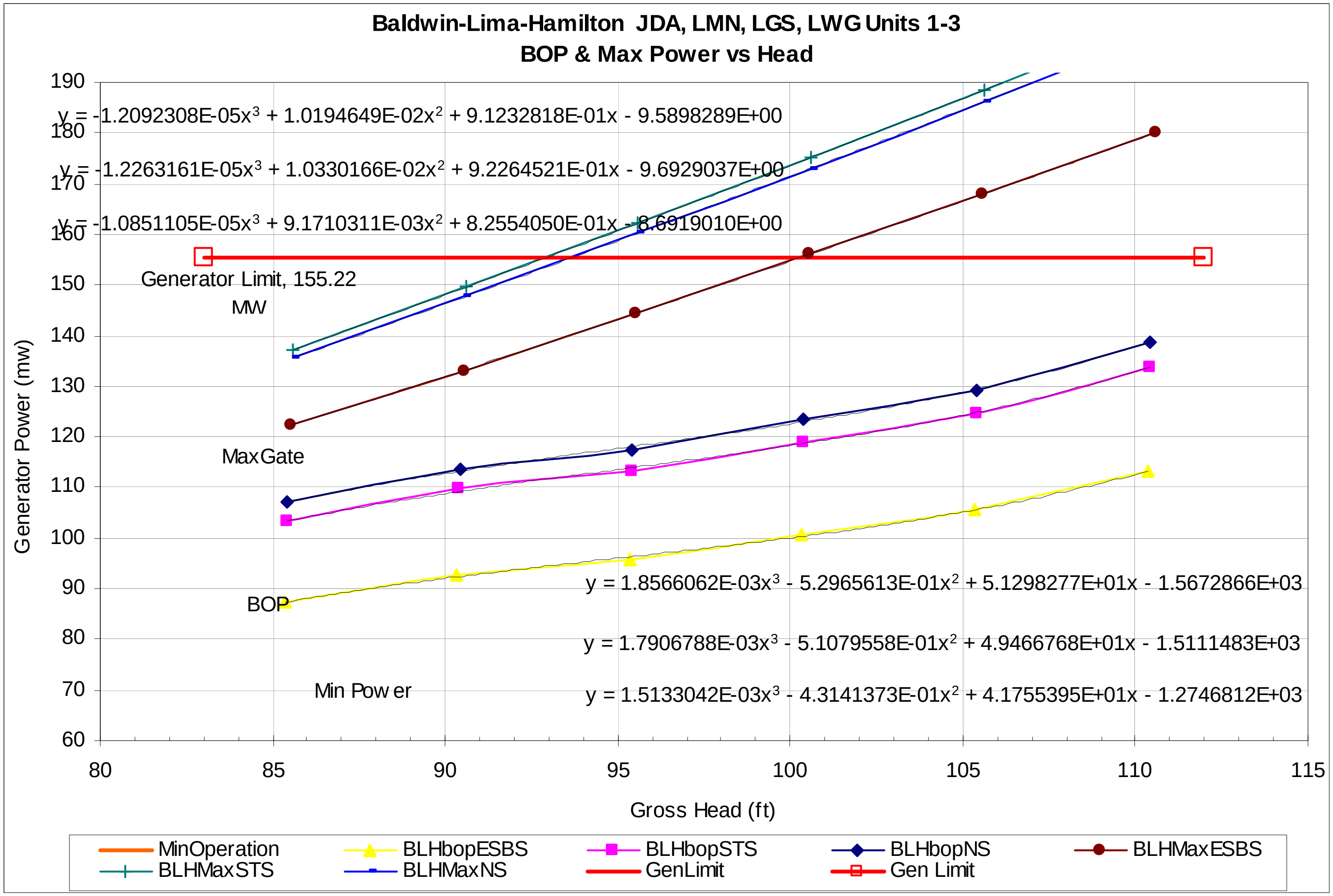


Table A-7. Performance with No Screens for Fixed Blade Propeller Unit

Proto Gross Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Generator Efficiency	Unit Efficiency	Generator Output (MW)
Best Gate						
85	153,161	86.5%	18,352	98.5%	85.2%	112.5
90	164,214	87.1%	18,456	98.5%	85.8%	120.6
95	174,027	87.6%	18,423	98.5%	86.3%	127.8
100	184,100	87.9%	18,452	98.5%	86.6%	135.2
105	194,802	88.2%	18,531	98.5%	86.9%	143.1
110	209,331	88.0%	19,052	98.5%	86.7%	153.8
Upper 1%						
85	159,557	85.5%	19,342	98.5%	84.2%	117.2
90	170,278	86.1%	19,359	98.5%	84.8%	125.1
95	180,789	86.6%	19,360	98.5%	85.3%	132.8
100	191,300	86.9%	19,394	98.5%	85.6%	140.5
105	202,967	87.2%	19,530	98.5%	85.9%	149.1
110	213,583	87.5%	19,550	98.5%	86.2%	156.9

Table A-8. Performance with STS for Fixed Blade Propeller Unit

Proto Gross Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Generator Efficiency	Unit Efficiency	Generator Output (MW)
Best Gate						
85	150,998	85.5%	18,305	98.5%	84.2%	110.9
90	161,895	86.1%	18,406	98.5%	84.8%	118.9
95	171,569	86.6%	18,373	98.5%	85.3%	126.0
100	181,500	86.9%	18,401	98.5%	85.6%	133.3
105	192,051	87.2%	18,479	98.5%	85.9%	141.1
110	197,960	87.5%	18,120	98.5%	86.2%	145.4
Upper 1%						
85	157,388	84.5%	19,305	98.5%	83.2%	115.6
90	167,964	85.1%	19,321	98.5%	83.8%	123.4
95	178,332	85.6%	19,320	98.5%	84.3%	131.0
100	188,700	85.9%	19,353	98.5%	84.6%	138.6
105	200,209	86.2%	19,488	98.5%	84.9%	147.1
110	210,680	86.5%	19,507	98.5%	85.2%	154.8

Table A-9. Performance with ESBS for Fixed Blade Propeller Unit

Proto Gross Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Generator Efficiency	Unit Efficiency	Generator Output (MW)
Best Gate						
85	133,900	84.0%	16,520	98.5%	82.7%	98.4
90	143,562	84.6%	16,609	98.5%	83.3%	105.5
95	152,141	85.1%	16,577	98.5%	83.8%	111.8
100	160,948	85.4%	16,602	98.5%	84.1%	118.2
105	170,306	85.7%	16,672	98.5%	84.4%	125.1
110	175,553	86.0%	16,347	98.5%	84.7%	128.9
Upper 1%						
85	140,246	83.0%	17,511	98.5%	81.8%	103.0
90	149,670	83.6%	17,523	98.5%	82.4%	109.9
95	158,909	84.1%	17,521	98.5%	82.8%	116.7
100	168,147	84.4%	17,550	98.5%	83.1%	123.5
105	178,403	84.7%	17,671	98.5%	83.4%	131.0
110	187,734	85.0%	17,687	98.5%	83.7%	137.9

Figure A-5. Fixed Blade Propeller, Best Operating Point and Max Power Efficiency vs. Head

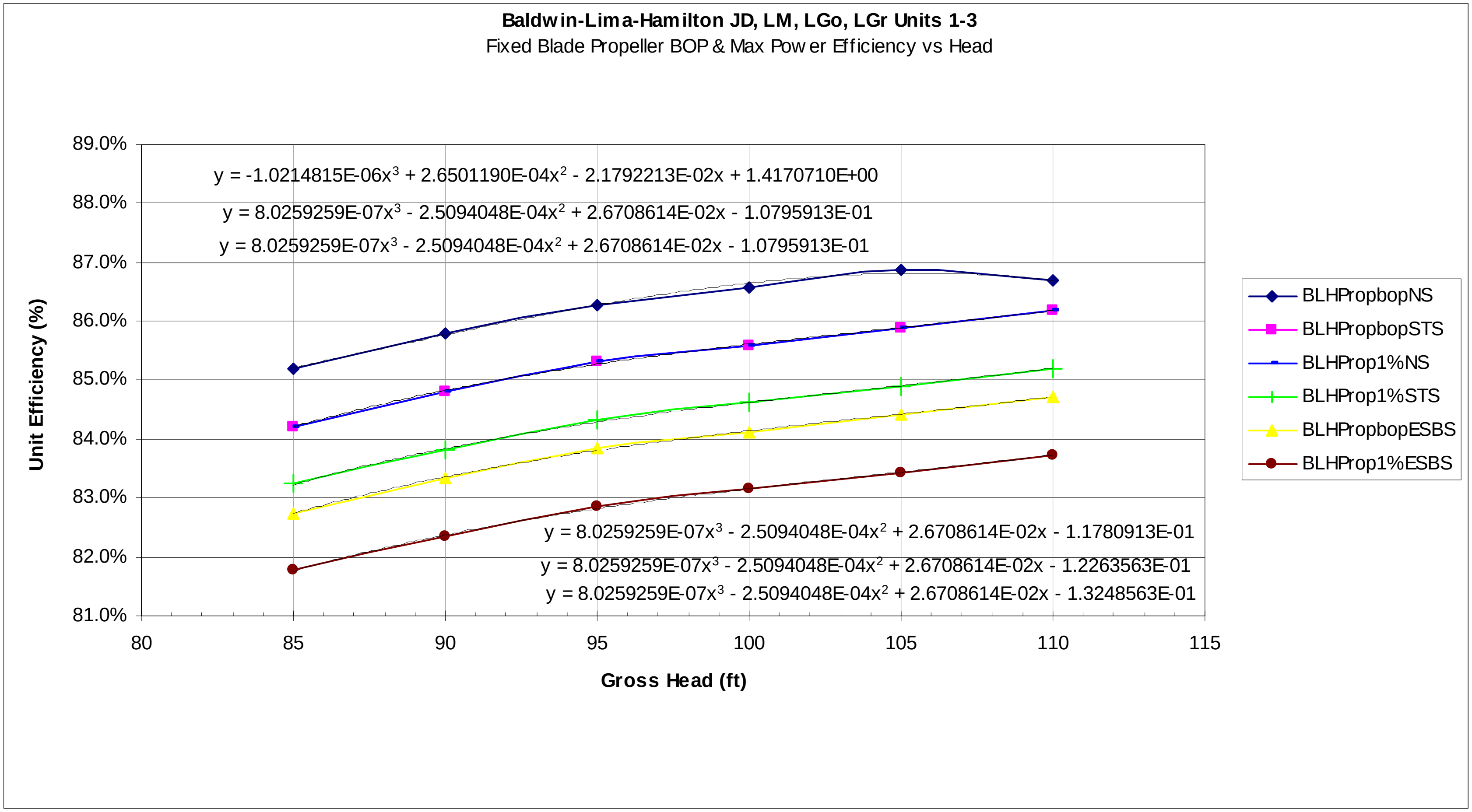


Figure A-6. Fixed Blade Propeller, Best Operating Point and Max Power vs. Head

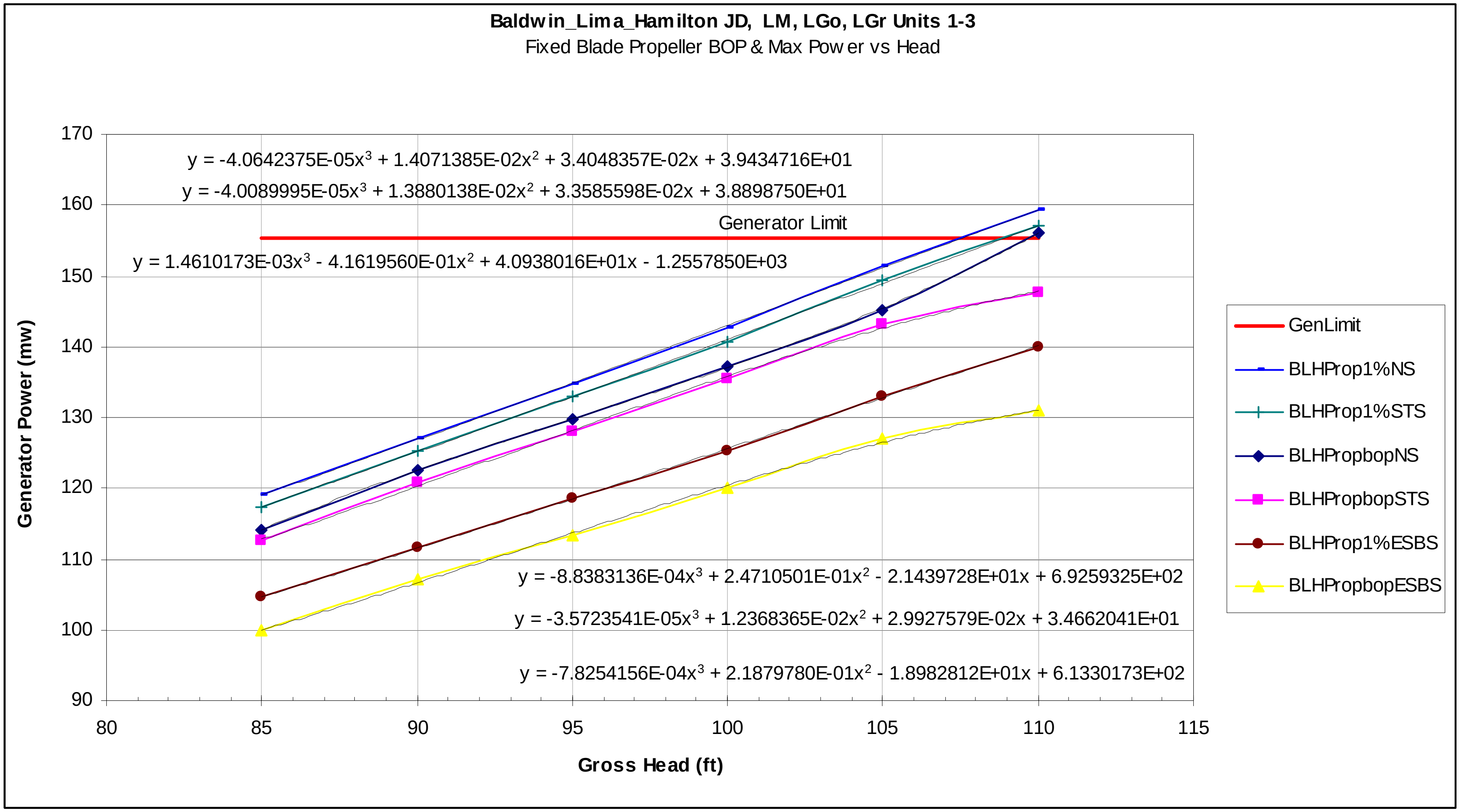


Table A-10. Performance with No Screens for AC Units 4-6 at Lower Snake

Minimum Power (@ 80%eff)								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	93,229	80.0	12,079	0.3	85.3	98.5%	78.79%	68.5
90	92,712	80.0	11,344	0.3	90.3	98.5%	78.76%	68.1
95	94,630	80.0	10,970	0.3	95.3	98.4%	78.75%	69.5
100	101,400	80.0	11,167	0.3	100.3	98.4%	78.76%	74.4
105	106,522	80.0	11,172	0.3	105.3	98.4%	78.76%	78.2
110	108,694	80.0	10,882	0.3	110.3	98.4%	78.75%	79.8
Lower 1%								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	116,532	88.7	13,617	0.3	85.3	98.5%	87.41%	85.6
90	124,687	89.2	13,691	0.3	90.3	98.5%	87.86%	91.6
95	132,133	89.4	13,706	0.3	95.3	98.5%	88.10%	97.1
100	140,700	89.7	13,827	0.3	100.3	98.6%	88.35%	103.4
105	149,231	89.8	13,951	0.3	105.3	98.6%	88.46%	109.7
110	156,939	89.9	13,982	0.3	110.3	98.6%	88.60%	115.3
Best Gate								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	122,596	89.7	14,166	0.3	85.3	98.6%	88.41%	90.1
90	133,571	90.2	14,504	0.3	90.3	98.6%	88.87%	98.2
95	144,855	90.4	14,860	0.4	95.4	98.6%	89.13%	106.5
100	153,833	90.7	14,951	0.4	100.4	98.6%	89.38%	113.1
105	164,812	90.8	15,238	0.4	105.4	98.6%	89.49%	121.2
110	172,963	90.9	15,240	0.4	110.4	98.6%	89.64%	127.2
Upper 1%								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	165,926	88.7	19,389	0.5	85.5	98.8%	87.61%	122.2
90	176,302	89.2	19,358	0.5	90.5	98.8%	88.06%	129.9
95	185,127	89.4	19,204	0.5	95.5	98.8%	88.30%	136.3
100	190,100	89.7	18,681	0.4	100.4	98.7%	88.53%	140.0
105	199,597	89.8	18,660	0.4	105.4	98.7%	88.62%	147.0
110	205,704	89.9	18,326	0.4	110.4	98.7%	88.76%	151.4
Maximum Output (Near Full Gate - about 96%)								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	183,354	80.9	23,505	0.6	85.56	98.9%	79.99%	135.3
90	195,146	81.7	23,381	0.6	90.56	98.9%	80.83%	144.0
95	207,177	82.4	23,317	0.6	95.56	98.9%	81.52%	152.8
100	218,333	83.1	23,147	0.6	100.56	98.9%	82.21%	161.1
105	231,028	83.7	23,159	0.6	105.56	98.9%	82.80%	170.4
110	242,868	84.4	23,060	0.6	110.55	98.9%	83.44%	179.2

Table A-11. Performance with STS for AC Units 4-6 at Lower Snake

Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
Minimum Power (@ 80%eff)								
85	97,458	80.0	12,627	0.3	85.3	98.5%	78.80%	71.6
90	96,918	80.0	11,859	0.3	90.3	98.5%	78.78%	71.2
95	98,923	80.0	11,467	0.3	95.3	98.5%	78.77%	72.6
100	106,000	80.0	11,673	0.3	100.3	98.5%	78.77%	77.8
105	111,355	80.0	11,679	0.3	105.3	98.5%	78.77%	81.8
110	113,625	80.0	11,375	0.3	110.3	98.5%	78.76%	83.4
Lower 1%								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	115,952	87.8	13,687	0.3	85.3	98.5%	86.53%	85.2
90	124,066	88.3	13,761	0.3	90.3	98.6%	86.98%	91.2
95	131,475	88.5	13,777	0.3	95.3	98.6%	87.22%	96.6
100	140,000	88.8	13,897	0.3	100.3	98.6%	87.47%	102.9
105	148,489	88.8	14,023	0.3	105.3	98.6%	87.57%	109.1
110	156,158	89.0	14,053	0.3	110.3	98.6%	87.72%	114.8
Best Gate								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	119,542	88.8	13,951	0.3	85.3	98.6%	87.53%	87.9
90	130,243	89.3	14,284	0.3	90.3	98.6%	87.98%	95.7
95	141,246	89.5	14,635	0.4	95.4	98.6%	88.24%	103.8
100	150,000	89.8	14,724	0.4	100.4	98.6%	88.48%	110.3
105	160,706	89.8	15,007	0.4	105.4	98.6%	88.59%	118.2
110	168,654	90.0	15,009	0.4	110.4	98.6%	88.74%	124.0
Upper 1%								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	170,203	87.8	20,090	0.5	85.5	98.8%	86.76%	125.4
90	180,847	88.3	20,059	0.5	90.5	98.8%	87.20%	133.2
95	189,899	88.5	19,898	0.5	95.5	98.8%	87.44%	139.9
100	195,000	88.8	19,357	0.5	100.5	98.8%	87.66%	143.6
105	204,742	88.8	19,335	0.5	105.5	98.8%	87.76%	150.8
110	211,006	89.0	18,989	0.5	110.5	98.8%	87.89%	155.4
Maximum Output (Near Full Gate - about 96%)								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	186,434	80.0	24,162	0.6	85.58	99.0%	79.15%	137.6
90	198,424	80.8	24,034	0.6	90.58	99.0%	79.98%	146.4
95	210,656	81.5	23,968	0.6	95.58	99.0%	80.66%	155.5
100	222,000	82.2	23,793	0.6	100.57	99.0%	81.34%	163.8
105	234,908	82.8	23,806	0.6	105.57	99.0%	81.93%	173.3
110	246,947	83.4	23,704	0.6	110.57	98.9%	82.56%	182.2

Table A-12. Performance with ESBS for AC Units 4-6 at Lower Snake

Minimum Power (@ 80%eff)								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	99,527	80.0	12,895	0.3	85.3	98.5%	78.81%	73.1
90	98,975	80.0	12,111	0.3	90.3	98.5%	78.79%	72.7
95	101,023	80.0	11,711	0.3	95.3	98.5%	78.77%	74.2
100	108,250	80.0	11,921	0.3	100.3	98.5%	78.78%	79.5
105	113,718	80.0	11,927	0.3	105.3	98.5%	78.78%	83.5
110	116,037	80.0	11,617	0.3	110.3	98.5%	78.77%	85.2
Lower 1%								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	112,639	86.6	13,483	0.3	85.3	98.5%	85.32%	82.8
90	120,521	87.0	13,556	0.3	90.3	98.5%	85.76%	88.6
95	127,719	87.3	13,572	0.3	95.3	98.5%	86.00%	93.9
100	136,000	87.5	13,691	0.3	100.3	98.5%	86.24%	99.9
105	144,246	87.6	13,814	0.3	105.3	98.6%	86.34%	106.0
110	151,697	87.8	13,844	0.3	110.3	98.6%	86.49%	111.5
Best Gate								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	117,151	87.6	13,863	0.3	85.3	98.6%	86.32%	86.1
90	127,638	88.0	14,194	0.3	90.3	98.6%	86.77%	93.8
95	138,421	88.3	14,542	0.3	95.3	98.6%	87.02%	101.8
100	147,000	88.5	14,631	0.4	100.4	98.6%	87.26%	108.1
105	157,492	88.6	14,912	0.4	105.4	98.6%	87.37%	115.8
110	165,281	88.8	14,914	0.4	110.4	98.6%	87.51%	121.5
Upper 1%								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	156,783	86.6	18,767	0.5	85.5	98.8%	85.51%	115.5
90	166,588	87.0	18,738	0.4	90.4	98.7%	85.94%	122.7
95	174,926	87.3	18,588	0.4	95.4	98.7%	86.17%	128.8
100	179,625	87.5	18,083	0.4	100.4	98.7%	86.40%	132.2
105	188,599	87.6	18,062	0.4	105.4	98.7%	86.49%	138.8
110	194,369	87.8	17,739	0.4	110.4	98.7%	86.63%	143.1
Maximum Output (Near Full Gate - about 96%)								
Proto Net Head (ft)	Proto Hp	Proto Efficiency	Proto Q	Head Loss	Gross Head	Generator Eff. (%)	Unit Efficiency	Generator Output (MW)
85	177,196	78.8	23,315	0.6	85.56	98.9%	77.93%	130.7
90	188,592	79.6	23,192	0.6	90.56	98.9%	78.75%	139.1
95	200,218	80.3	23,128	0.6	95.56	98.9%	79.42%	147.7
100	211,000	81.0	22,959	0.6	100.55	98.9%	80.09%	155.6
105	223,269	81.5	22,972	0.6	105.55	98.9%	80.67%	164.7
110	234,711	82.2	22,874	0.5	110.55	98.9%	81.29%	173.1

Figure A-7. AC Best Operating Point and Maximum Power vs. Head

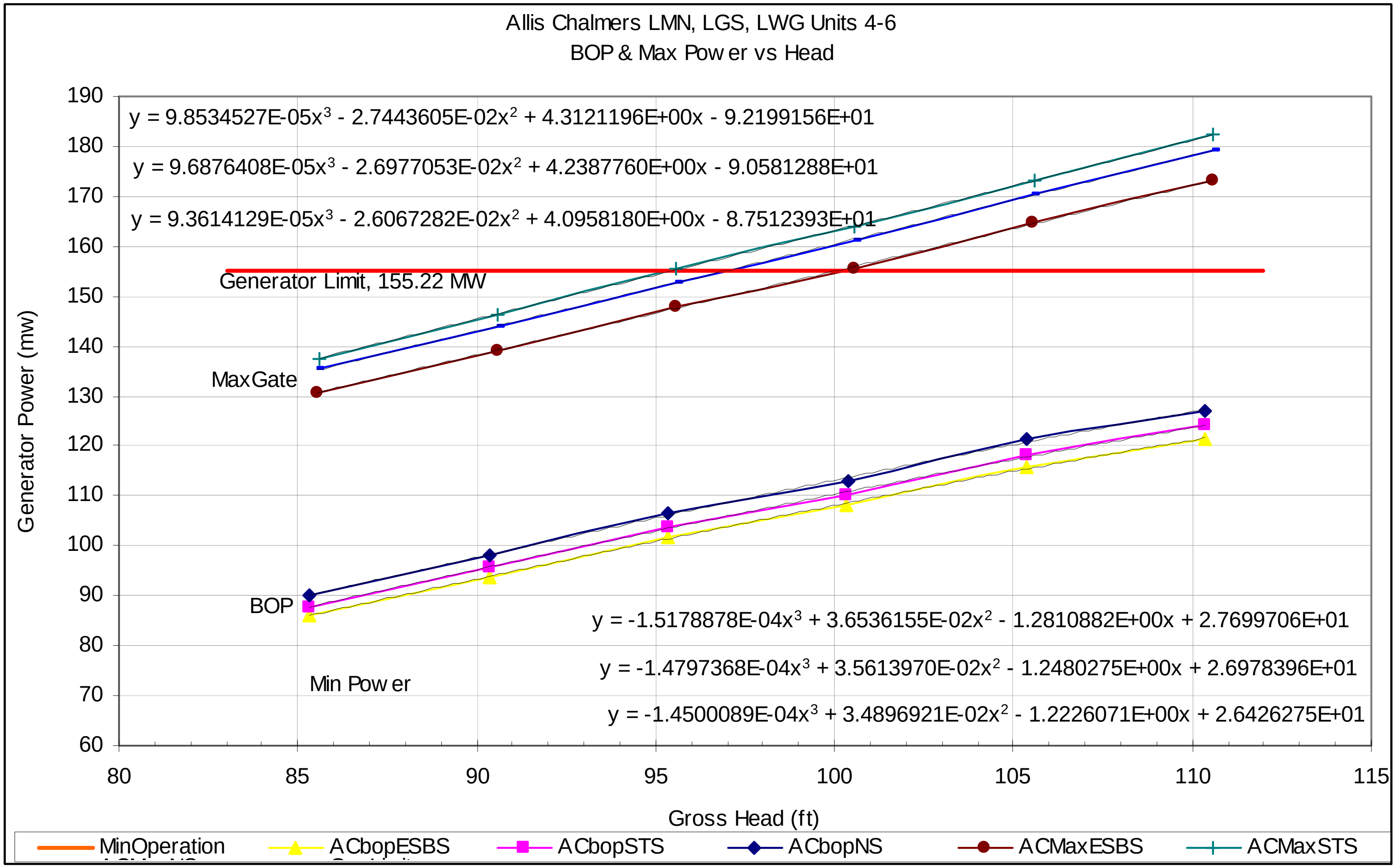
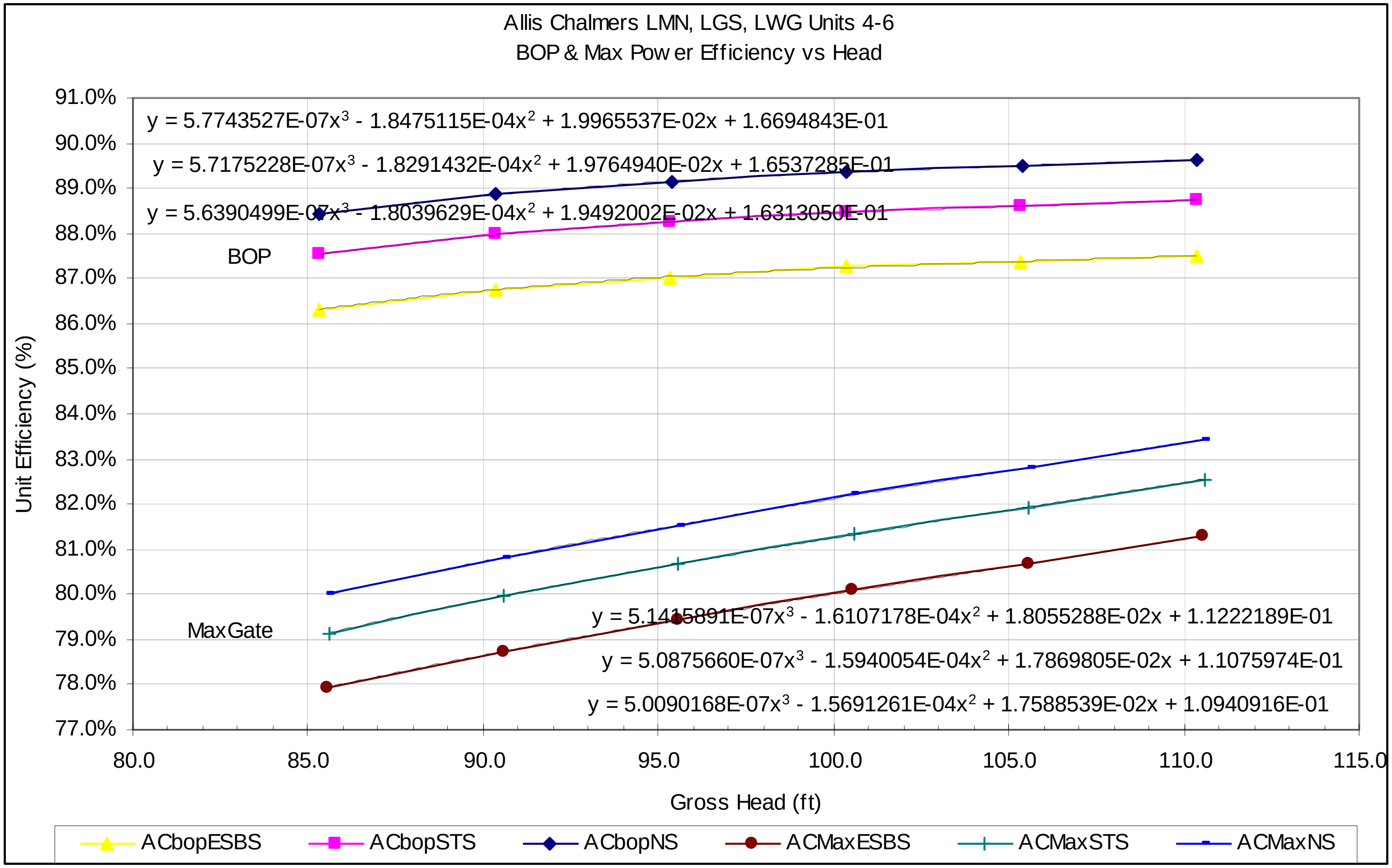


Figure A-8. AC Best Operating Point and Maximum Power Efficiency vs. Head



A.3.0. Designs to Fix Blades into Position and Fill Hub-Blade Gaps

A.3.1. Temporary Repair – Weld Blocks to Hub

In the late 1970s and 1980s when the John Day turbines were having blade adjustment system failures (described earlier), they were failing faster than they could be repaired. To enable a failed unit to continue to operate, the manufacturer (BLH) recommended a temporary repair – welding steel blocks onto the hub above and below the trailing edge of the blade at a specified blade angle. The BLH specified the size of the blocks and welds to be used. This was done on numerous units and was successful; that is, no failures of the blocks or welds occurred. The presence of the steel blocks in the waterway did cause some cavitation to adjacent steel surfaces and probably also created a hazard to juvenile fish which pass nearby the blocks. Moreover, there was probably a small efficiency loss as well but that was never measured and may, in fact, be too small to measure.

When the blade adjustment mechanism on Lower Monumental unit 1 failed in 2005, blocks were welded to the hub in the same manner as was done on the John Day turbines decades before. Figures A-9 and A-10 depict how these blocks were attached to the hub.

Figure A-9. Elevation View of Hub with Blade Blocks

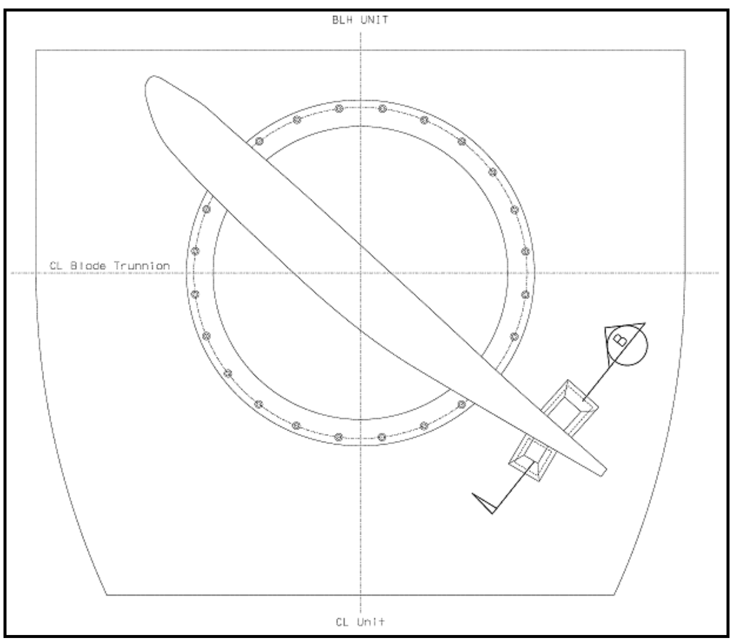
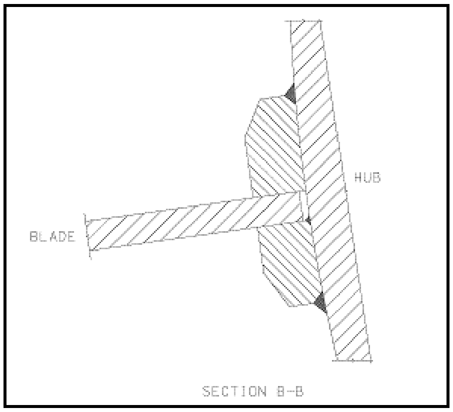


Figure A-10. Section Showing Cross-section of Blocks Capturing Blade



A.3.2. Permanent Repair – Pinning the Blades

This repair process involves drilling and reaming/boring three 2.5-inch diameter holes through each blade's disc into the hub, inserting pins into the holes, and sealing welding cover plates over the holes (Figures A-11 and A-12). This work can be done "in place" with a special portable machine tool and a fixture mounted to the blade to rigidly support the boring bar. The principle advantage of this type of repair is that there are no protruding blocks into the waterway to induce cavitation and harm fish. Moreover, although this is a "permanent" repair, it can be reversed in the future should the decision be made to return the unit to a Kaplan type. In other words, installing the pins does not cause irreversible damage to the affected parts.

Figure A-11. John Day Runner Hub Showing Location of Pins

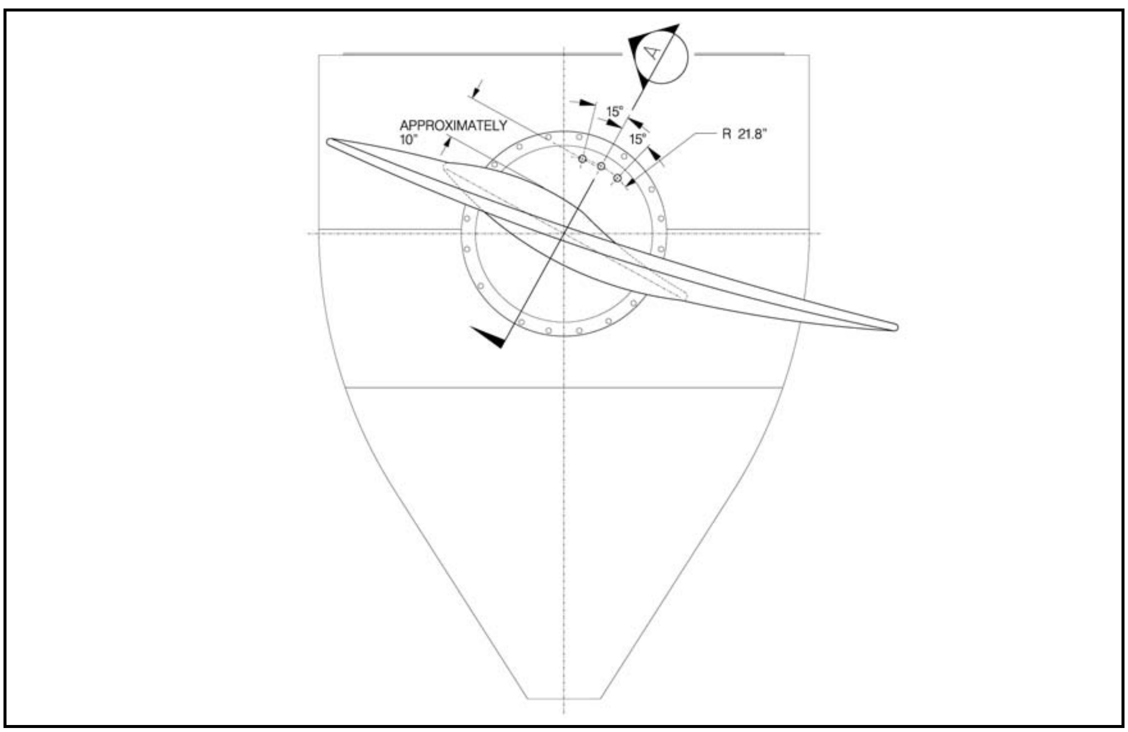
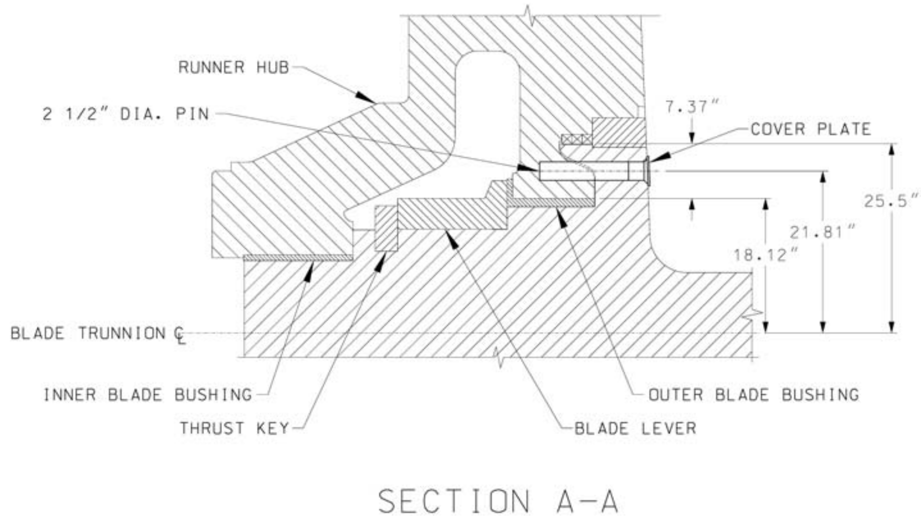


Figure A-12. BLH Hub/Blade Assembly



A.3.3. Closing the Gaps between Discharge Ring and Blade Tips

Measurements of the gaps between the hub and blade and between the discharge ring and the blade's tips were taken on a John Day turbine (unit 9) at various blade angles. From these data, the clearance was determined for an approximate blade angle of 29 degrees in an effort to estimate what the cost might be for filling these gaps. Figures A-13 to A-15 shows the blade/hub and blade/discharge ring clearances for John Day unit 9 at a blade angle of 28.75 degrees. As can be seen from the figures, there is no need to close the gap between the hub and blade because it is already small at 0.5- to 0.75-inch. Only the clearances at the blade tips are feasible to close. One process to perform this work would be to fabricate prototype filler pieces from steel sheet or other suitable materials when the blade pinning work is being performed. These prototype filler pieces can then be used to cast stainless steel inserts which can then be welded to the periphery of each blade. This work is expected to take an additional 12 weeks (in addition to the time required to pin the blades) and add a cost of $230,000 in materials and labor. Note there is a one-time cost of $25,000 to make the patterns. Doing this work on subsequent units will add $205,000 to the blade pinning cost.

Figure A-13. Blade/Hub and Blade/Discharge Ring Clearances for John Day Unit 9

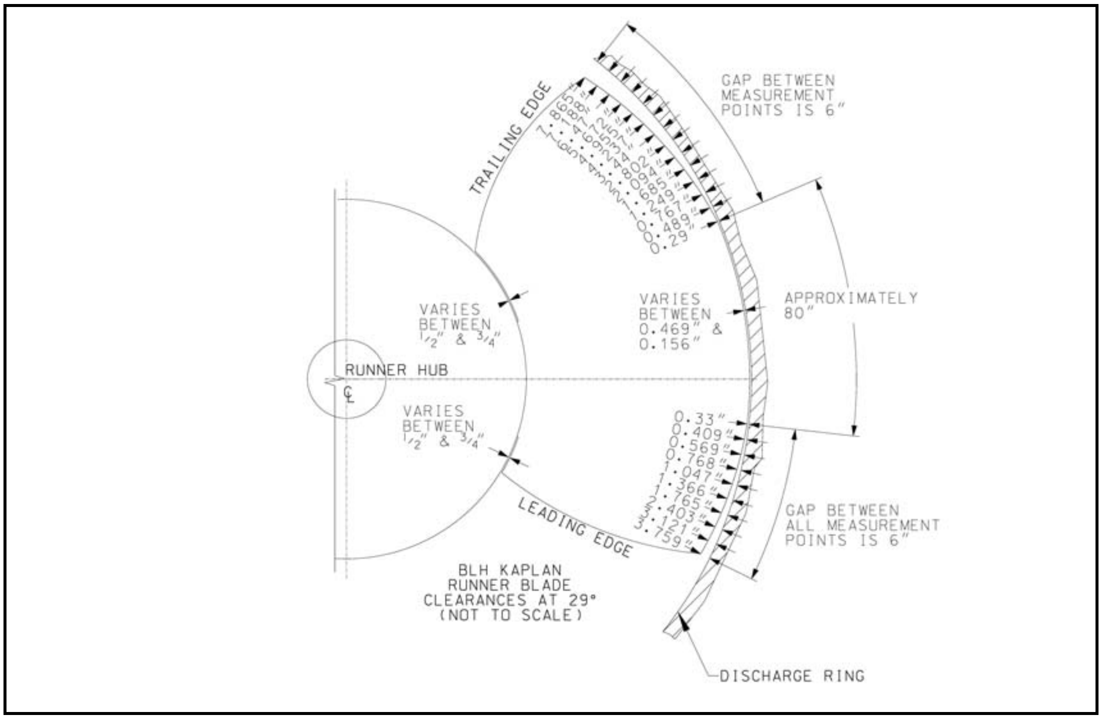


Figure A-14. Gap Filler Segment

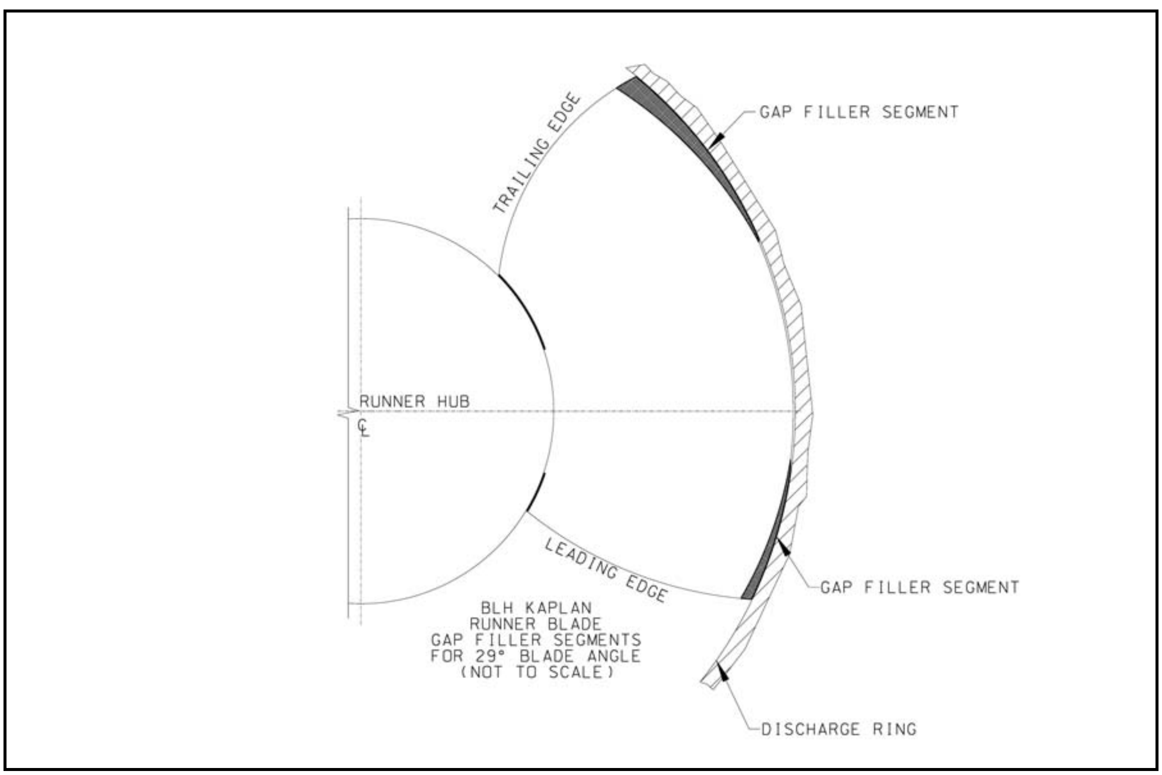
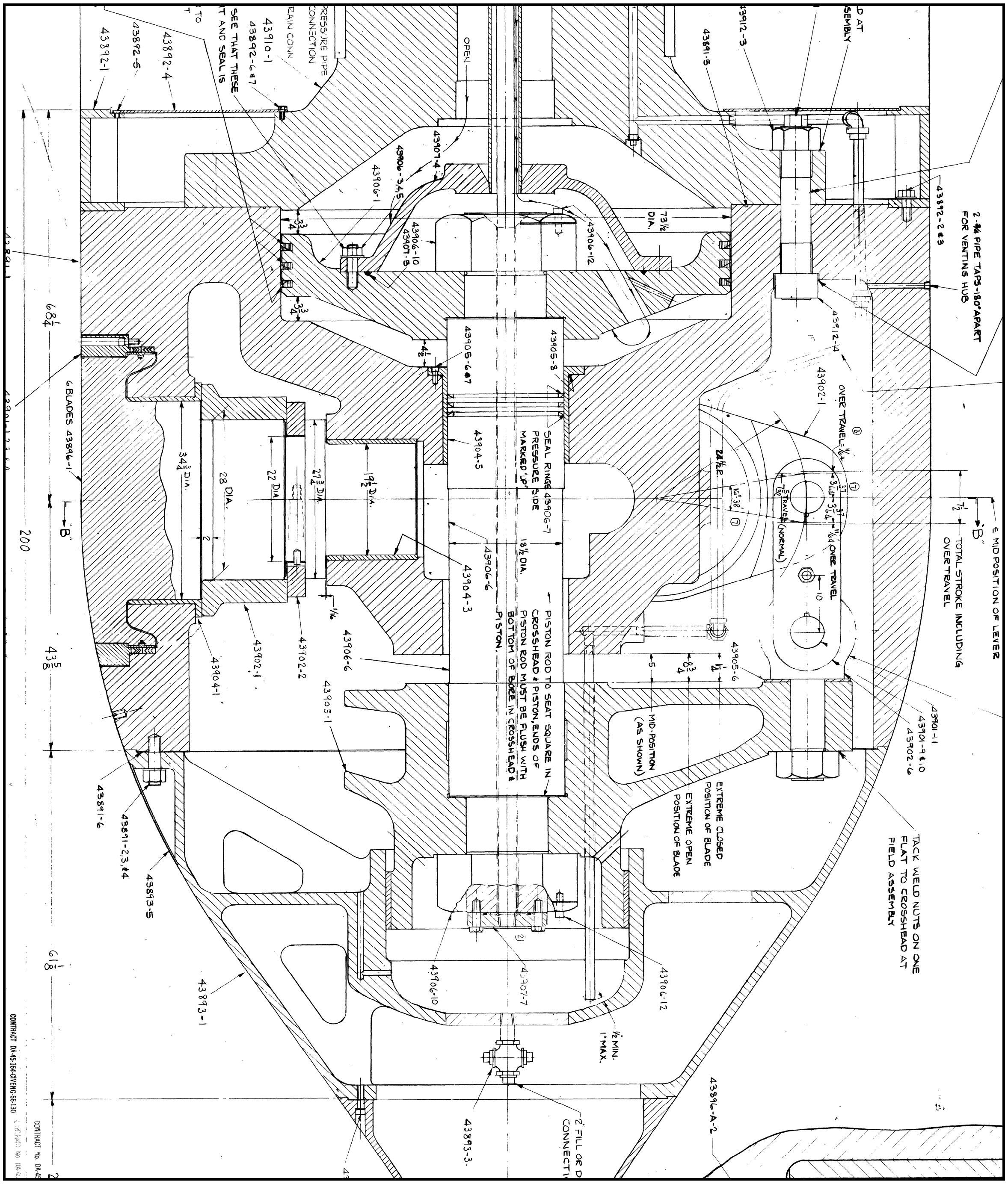


Figure A-15. Cross-section of Runner Hub Operating Mechanism



Appendix B
Biological and Environmental Considerations

Appendix B
Biological and Environmental Considerations

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B.1.0. Background

The Kaplan turbine blade linkages of the 25 Baldwin-Lima-Hamilton (BLH) turbines at Lower Granite, Little Goose, Lower Monumental, and the John Day hydroelectric projects are prone to failure (see Appendix A). A repair strategy is being developed to determine if pinning or welding the blades in a fixed position is a feasible alternative should the blade linkages of these units fail. This Appendix provides an evaluation to determine from an environmental perspective which, if any, of these 25 Kaplan turbine units can be converted to a fixed bladed (propeller) turbine or if they should be repaired on failure to retain their full range of movement. Appendix C recommends an appropriate blade angle for the fixed blade position of those units that may be converted to a propeller turbine.

B.2.0. Biological Considerations

The Corps' projects on the Snake and Columbia rivers have facilities for mitigating passage of migrating adult and juvenile fish. Primary species of interest include Chinook, coho, and sockeye salmon, steelhead trout, Pacific lamprey, and American shad. Other species, such as sturgeon, may utilize the fishways but in lesser numbers. Criteria for operating these facilities are contained in the Corps' annual Fish Passage Plan (FPP), along with criteria for operating and maintaining turbine units and turbine unit operating ranges and priorities. Biological Opinions prepared for Section 7 consultations under the Endangered Species Act have requirements for project operations including operation and maintenance of fish passage facilities, turbine units, and spillways.

B.2.1. Adult Fish Passage

Across the projects, adult fishway entrances are located near turbine discharge areas in order to attract upstream migrating adult fish into the fishways. Fishway entrances attract fish into collection channels that lead them to the base of each fish ladder, where migrating adult fish swim up and pass into the forebay above each dam. Auxiliary water supply systems add additional water to the collection channels to provide more fish attraction flows into the tailraces below each dam and to provide sufficient velocity within the channels to keep adult fish moving up the channels to the fish ladders. Fishway entrances are normally located on both ends of the powerhouses and adjacent to each end of the spillways. Where powerhouses and spillways are adjacent to each other, one set of entrances at the end of the powerhouse collection channel normally services both areas. The Corps' FPP contains operating criteria for each fishway entrance and collection channel.

Powerhouses and spillways are normally operated in a manner to attract fish towards the adult entrances. Spill patterns were developed using hydraulic modeling to ensure that discharge patterns at various flow levels lead fish to the entrances and do not hydraulically block adult entrances. Turbine unit operating priorities were also developed and included in the FPP to enhance attraction to the main entrances across the powerhouses.

B.2.2. Juvenile Fish Passage

Downstream migrating juvenile fish pass projects by passing through juvenile bypass systems, sluiceways, turbine units, and spillways. Juvenile bypass systems usually have outfalls located in areas of the tailraces where positive downstream flows are present to facilitate juvenile movement out of the project area. Some of the dams have spillway weirs installed to enhance juvenile passage through the spillways. The FPP contains operating criteria for each project for juvenile fish passage. The criteria specify operating priorities for turbine units to enhance juvenile passage through the bypass systems by operating units that receive higher passage or higher survival first, and/or to provide positive downstream flow conditions at juvenile outfalls. Spillways are operated during the main juvenile passage season to bypass juvenile fish past the project with minimum mortality and delays. Each project has specific Biological Opinion requirements for spilling for juvenile fish passage. Spill patterns were developed to both attract juvenile fish through the spillway and to improve tailrace egress juvenile fish while still providing for adult attraction. Overall emphasis of these project operations is to operate the projects in a balanced manner to improve juvenile passage with minimal delays in their forebay and tailrace.

B.2.3. Turbine Operations and Fish Passage

The Corps' FPP contains criteria for operating turbine units. Unit operating priorities are included in the FPP for each project to provide for both adult and juvenile fish passage. Operating priorities may be different for daytime where the emphasis may be on adult passage than at nighttime when the emphasis may change to juvenile fish passage. Operating priorities take into account tailrace flow patterns for adult attraction, flow at juvenile outfalls, and overall tailrace egress for juvenile fish. Growing evidence suggests that significant delay and predation may be associated with the gyre and eddies established by heavy spill and specific turbine operations. Taking units off line for repair may exacerbate the formation of reverse flow gyre and eddies affording predator's easy access to migrating salmon. Some operating priorities may change at night at projects where units with higher juvenile fish survival may be operated as first priority without as much regard to adult passage concerns in the tailraces. All projects have requirements for operating turbine units within 1% of best efficiency during the juvenile passage season.

B.3.0. Project Specific Operating Conditions and Configuration

B.3.1. Lower Granite Dam

Lower Granite has six turbine units, three BLH units and three AC units. Turbine units 1-3 have BLH turbines, which were installed in 1975 as part of the original dam construction. Turbine units 4 through 6 have AC turbines that were installed in 1978 under the powerhouse expansion contract. The history of linkage problems for the 3 BLH turbines is listed in Appendix A, *Turbine Engineering*. All turbines presently have full Kaplan configuration. The intakes for all 6 units are screened with extended length submerged bar screens (ESBS) and are required to operate within 1% of best efficiency during the fish passage season from April 1 through October 31.

B.3.1.1. <u>Turbine Unit Operation Priority (from FPP)</u>

Turbine units at Lower Granite are operated to enhance adult and juvenile fish passage from March 1 through December 15. During this period, turbine units will be operated as needed to meet generation requirements in the priority order shown in Table B-1. Unit operating priority may be coordinated differently to allow for fish research, construction, or project maintenance activities. To minimize mortality to juvenile fish passing through the turbines from April 1 through October 31 (or as long as there is sufficient river flow and/or generation requests to operate units 4, 5, or 6 within 1% of best efficiency), operating priority during nighttime hours from 2000 to 0400 hours shall be 4, 5, and 6 (in any order) and then units 1, 2 and 3 as needed (Table B-1). If a unit is taken out of service for maintenance or repair, the next unit in the priority list shall be operated.

Table B-1. Turbine Units Operating Priority for Lower Granite Dam

Season	Time of Day	Unit Priority
March 1 – December 15	24 hours	1, 2, 3, then 4-6 (any order)
April 1 – October 31 (if there is enough flow to run priority units)	Nighttime (2000 to 0400 hours)	4-6 (in any order, then 1-3 (as needed)
December 16 – February 28	24 hours	Any Order

B.3.1.2. Turbine Unit Operations

The FPP requires all turbine units to be operated within 1% of best efficiency from April 1 through October 31 as specified in load shaping guidelines (Appendix C of the FPP). These guidelines allow some deviation from the 1% best operating range for coordinated fishery measures, some maintenance activities, system reliability needs, and emergency generation requirements. Between November 1 and March 31, turbine units continue to be operated within the 1% best efficiency range, except when Bonneville Power Administration (BPA) load requests require the units to be operated outside the 1% range. Tables with operating ranges for the turbine units within the 1% best efficiency range at various head levels are contained in the FPP.

B.3.1.3. Minimum Generation Requirements

The Lower Granite powerhouse may be required to keep one generating turbine unit on line at all times to maintain power system reliability. During low flows, there may not be enough river flow to meet this generation requirement and required minimum spill for juvenile fish passage. Under these circumstances, the power generation requirement for system stability takes precedence over the minimum spill requirement. At Lower Granite, minimum generation requirements are 11-12 thousand cubic feet per second (kcfs) for turbine units 1-3 and 12.5-13.5 kcfs for turbine units 4-6.

B.3.1.4. Operating Pool Elevation

Lower Granite Lake operates over a 5-foot range from elevations 733-738 feet mean sea level (all elevations in this appendix are in mean sea level). From about April 3 through mid-September each year, the reservoir is operated at minimum operating pool (MOP), the bottom foot of this range from elevation 733-734 feet, to improve juvenile fish passage through the reservoir.

B.3.1.5. Configuration and Operation for Fish Passage

Adult passage facilities. The adult fish passage facilities at Lower Granite are made up of one fish ladder on the south shore, two south shore entrances, a powerhouse collection system, north shore entrances with a transportation channel underneath the spillway to the powerhouse collection system, and an auxiliary water supply system. The powerhouse collection system is comprised of four operating floating orifices, two downstream entrances on the north end of the powerhouse, and a common transportation channel. The auxiliary water is supplied by three electric pumps that pump water from the tailrace. Two pumps are normally used to provide required attraction flows.

Juvenile passage facilities. The juvenile facilities consist of a screened turbine intake bypass system and juvenile transportation facilities. The bypass system contains ESBS screens with flow vanes, vertical barrier screens, 10-inch gate well orifices, a bypass channel running the length of the powerhouse, and a bypass pipe to transport the fish to the transportation facilities or to the river. The transportation facilities include an upwell and separator structure to separate the juveniles from the excess water and adult fish, raceways for holding fish, a distribution system for distributing the fish among the raceways or to the barge or back to the river, a sampling and marking building, truck and barge loading facilities, and passive integrated transponder (PIT) tag detection and diversion systems.

Spillway passage. Lower Granite has eight spillbays for passing flows above powerhouse capacity, or to intentionally spill for juvenile fish passage during the spring and summer. Spillbay 1 (bay closest to powerhouse) contains a removable spillway weir (RSW) that is used to provide a surface spill for juvenile fish passage. When the RSW is operated, additional spillbays are operated to provide training flow to provide for balanced flow conditions in the tailrace for juvenile egress.

B.3.1.6. Environmental Considerations for Retaining Turbine Units as Kaplan or Converting to Fixed Blade Units on Failure of Linkages

As discussed previously, turbine unit operating priorities are listed in the Corps' FPP. Normal turbine operating priorities at Lower Granite are for adult passage during the day and juvenile passage at night. Turbine unit 1 operates as the priority unit for adult passage during the day. In the past, it was believed that operation of unit 1 for adult passage was always required. However, this has not been proven over time. Long periods of time without unit 1 operating at various Snake River projects have occurred due to turbine 1 failure and contracts to repair the units. No noticeable differences in passage numbers have been observed during these outages. Research conducted in the fall of 1993 and 1994 operating north powerhouse unit priority versus the normal south powerhouse priorities showed no significant passage differences. While it is still the intent to operate unit 1 at each project when available, this provides some flexibility regarding whether or not a unit has to retain Kaplan capability or if it can be converted to fixed blade unit if there is a linkage failure.

The Corps needs to maintain the capability of operating turbine unit 1 or 2 for adult passage at all river flows, which require retaining the Kaplan configuration on one of the two turbine units. Operation of units 1 or 2 may also be required for juvenile tailrace egress at all river flows. Turbine unit 3 can be either retained in its Kaplan configuration or made into a fixed bladed unit without constraint from the configuration of the other two units. If two of the three BLH turbine units become fixed bladed units, then the turbine unit operating priorities should be reviewed to ensure that two of the three units are operated when four units across the powerhouse operate.

B.3.2. Little Goose Dam

Little Goose has six turbine units, three BLH units and three AC units. Turbine units 1-3, from south to north, have BLH turbines and were installed in 1970 as part of the original dam construction. Turbine units 4 through 6 have AC turbines and were installed in 1978 under the powerhouse expansion contract. The history of linkage problems for the three BLH turbines is listed in Appendix A. All turbines presently have full Kaplan configuration. The intakes for all six turbine units are screened with ESBS and are required to operate within 1% of best efficiency during the fish passage season from April 1 through October 31.

B.3.2.1. Turbine Unit Operation Priority (from FPP)

The Little Goose turbine units will be operated to enhance adult and juvenile fish passage from March 1 through November 30. During this period, the turbine units will be operated in the priority order shown in Table B-2. Unit operating priority may be coordinated differently to allow for fish research, construction, or project maintenance activities. Turbine unit operating priority shall be unit 1, then turbine units 2 through 6. If more than one turbine unit is operating maximize discharge (i.e. operated at the upper 1% limit) through the southernmost turbine units to the extent possible without exceeding 1% guidelines, starting with turbine unit 1. If a turbine unit is taken out of service for maintenance or repair, the next unit in the priority list shall be operated.

Table B-2. Turbine Units Operating Priority for Little Goose Dam

Season	Time of Day	Unit Priority
March 1 – November 30	24 hours	1, 2, 3, 4, 5, 6 (maximize discharge through lowest numbered turbine units)
December 1 – February 28	24 hours	Any Order

B.3.2.2. Turbine Unit Operations

The FPP requires all turbines to be operated within 1% of best efficiency from April 1 through October 31 as specified in load shaping guidelines (Appendix C of the FPP). These guidelines allow some deviation from the 1% best operating range for coordinated fishery measures, some maintenance activities, system reliability needs, and emergency generation requirements. Between November 1 and March 31, turbine units continue to be operated within the 1% best efficiency range, except when BPA load requests require the units to be operated outside the 1% range. Tables with operating ranges for the turbine units within the 1% best efficiency range at various head levels are contained in the FPP.

Little Goose has turbine operating requirements that are different from those at other projects. When the project is spilling for juvenile fish passage, tailrace configuration and percent of flow spilled may result in eddying conditions in the tailrace. Operations with over 30% of the project discharge spilled, or some spill patterns for spilling for juvenile fish passage have resulted in large tailrace eddies that block or significantly delay adult fish passage. Hydraulic modeling of project operations showed that maximizing discharge through the southernmost turbine units, particularly turbine unit 1, helps to alleviate the eddying conditions. Consequently, Little Goose has turbine operating loading criteria in the FPP (see Section B.3.2.1.) that is not included in the criteria for other Walla Walla District projects.

B.3.2.3. Minimum Generation Requirements

The Little Goose powerhouse may be required to keep one generating turbine unit on line at all times to maintain power system reliability. During low flows, there may not be enough river flow to meet this generation requirement and required minimum spill. Under these circumstances, the power generation requirement for system stability will take precedence over the minimum spill requirement. At Little Goose Dam, minimum generation requirements are 11-12 kcfs for turbine units 1-3 and 17-19 kcfs for units 4-6.

B.3.2.4. Operating Pool Elevation

Lake Bryan operates over a 5-foot range from elevations 633-638 feet. From about April 3 through the beginning of September each year, the reservoir is operated at MOP, the bottom foot of this range from elevation 633-634 feet, to improve juvenile fish passage through the reservoir.

B.3.2.5. Configuration and Operation for Fish Passage

Adult passage facilities. The adult fish passage facilities at Little Goose are made up of one fish ladder on the south shore, two south shore entrances, a powerhouse collection system, north shore entrances with a transportation channel underneath the spillway to the powerhouse collection system, and an auxiliary water supply system. The powerhouse collection system is comprised of two downstream entrances on the north end of the powerhouse, and a common transportation channel. The floating orifices along the collection channel are closed. The auxiliary water is supplied by three turbine-driven pumps that pump water from the tailrace. All three pumps are normally operated to provide the required attraction flows. Additional water is supplied to the auxiliary water supply system from the juvenile fish facilities primary dewatering structure.

Juvenile passage facilities. The juvenile facilities consist of a screened turbine intake bypass system and juvenile transportation facilities. The bypass system contains ESBS screens with flow vanes, vertical barrier screens, 12-inch gate well orifices, and a bypass channel running the length of the powerhouse, a dewatering structure to eliminate excess water, and a corrugated metal flume to transport the fish to the either transportation facilities or to the river. The transportation facilities include a separator structure to separate the juveniles from the excess water and adult fish, raceways for holding fish, a distribution system for distributing the fish among the raceways or to the barge or back to the river, a sampling and marking building, truck and barge loading facilities, and PIT tag detection and diversion systems.

B.3.2.6. Sport Fishery Concerns

Sport fishing for adult steelhead and salmon is a very popular activity in the Little Goose tailrace. This is the only location on the lower Snake River projects where anglers can consistently catch anadromous fish without using a boat. Anglers fish along “the wall” which is the concrete tailrace deck area stretching from just below the fish pump intakes to just downstream of the navigation lock drain conduit outlet, and also on the tailrace fishing platform on the peninsula. Catching fish is dependant on turbine unit 1 operations. When the unit is operating, fish travel up along “the wall” to the south shore entrances and are available for anglers to catch. If unit 1 is not operating, angling success decreases dramatically as fish do not appear to move up along “the wall” to the south shore fishway entrances. When unit 1 is operating and there is a large eddy due to spill exceeding 30%, the flow along the wall is moving upstream instead of downstream and anglers do not catch any fish. Total adult passage under these conditions, as occurred in the summer of 2005 and spring of 2007, can be delayed or blocked by the reverse flow conditions.

It is important to the Corps and the public to retain the angling and passage success at Little Goose not only for the recreation program but also to satisfy mitigation responsibilities. Mitigation for construction of the four lower Snake River projects included construction of fish hatcheries for passage mortalities and mitigation for lost fishing opportunities (boat ramps and access points above and below the dams).

B.3.2.7. Environmental Considerations for Retaining Turbine Units as Kaplan or Converting to Fixed Blade Units on Failure of Linkages

As discussed previously, turbine unit operating priorities are listed in the Corps' FPP. Turbine operating priorities at Little Goose are to load the powerhouse from south to north during the fish passage season. Maintaining this priority, especially unit 1 operations, is especially critical when the project is spilling. If the percent of project discharge exceeds 30%, tailrace configurations result in severe eddying in front of the powerhouse and along the north shore. Spill operations in 2005 and 2007 with less than full powerhouse operation, demonstrated that adult fish can be severely delayed or passage curtailed under these eddying conditions. Modeling at the Engineer Research and Development Center for installation of spillway weirs demonstrated that being able to operate turbine unit 1 at all flows is critical to reducing tailrace eddying conditions in front of the powerhouse. While turbine unit 1 operations may not always be required for adult passage in non-spill conditions, as explained for Lower Granite, requirements to operate unit 1 during all spill conditions requires retaining full Kaplan configuration on this unit. Kaplan configuration should also be retained on either unit 2 or 3 to help provide southern powerhouse discharges over the maximum range of spill conditions. Thus, changing to a fixed blade configuration at Little Goose due to a linkage failure is possible on either unit 2 or 3, but not both.

B.3.3. Lower Monumental Dam

Lower Monumental has six turbine units, three BLH units and three AC units. Turbine units 1-3, from north to south, have BLH turbines and were installed in 1969 as part of the original dam construction. Turbine units 4 through 6 have AC turbines and were installed in 1979 under the powerhouse expansion contract. The history of linkage problems for the three BLH turbines is listed in Appendix A. Turbine unit 1 is presently welded in a fixed bladed position. The remaining 5 turbines have full Kaplan configuration. The intakes for all six turbine units are screened with submersible traveling bar screens (STS) and are required to operate within 1% of best efficiency during the fish passage season, from April 1 through October 31.

B.3.3.1. Turbine Unit Operation Priority (from FPP)

When in operation, turbine units will be operated to enhance adult and juvenile fish passage from March 1 through November 30. During this time period turbine units will be operated as needed to meet generation requirements in the priority order shown in Table B-3. Unit operating priority may be coordinated differently to allow for fish research, construction, or project maintenance activities. If a turbine unit is taken out of service for maintenance or repair, the next unit on the priority list will be operated.

Table B-3. Turbine Units Operating Priority for Lower Monumental Dam

Season	River Flow	Spill Level	Unit Priority
March 1 – November 30	Less than 75 kcfs	While spilling 50%	2, 5*, 3, 4, 6 then 1
	75 to 100 kcfs	While spilling 45%	2, 5*, 3, 4, 6 then 1
	Over 100 kcfs	While spilling 50% or to gas cap	1**, 5*, 2, 3, 4, then 6
	Any river flow	No spill	2, 3, 4, 5, 6 then 1***
December 1 – February 28	Any river flow	Any spill level, including no spill	Any order

*If U5 is OOS, run U4. **If U1 is OOS, run U2. ***If no spill is occurring, U1 may be operated at any priority level at the discretion of project personnel. **NOTE**: U1 has fixed-pitch blades and can operate only at about 130 megawatts.

B.3.3.2. Turbine Unit Operations

The FPP requires all turbine units to be operated within 1% of best efficiency from April 1 through October 31 as specified in load shaping guidelines (Appendix C of the FPP). These guidelines allow some deviation from the 1% best operating range for coordinated fishery measures, some maintenance activities, system reliability needs, and emergency generation requirements. Between November 1 and March 31, turbine units continue to be operated within the 1% best efficiency range, except when BPA load requests require the units to be operated outside the 1% range. Tables with operating ranges for the turbine units within the 1% best efficiency range at various head levels are contained in the FPP.

B.3.3.3. Minimum Generation Requirements

The Lower Monumental powerhouse may be required to keep one generating turbine unit on line at all times to maintain power system reliability. During low flows, there may not be enough river flow to meet this generation requirement and required minimum spill. Under these circumstances the power generation requirement for system stability will take precedence over the minimum spill requirement. At Lower Monumental, minimum generation requirements are 11-12 kcfs for turbine units 2-3 and 17-19 kcfs for turbine units 4-6. Turbine unit 1 has fixed blades and cannot meet these minimum generation requirements.

B.3.3.4. Operating Pool Elevation

Lake Herbert G. West operates over a 3-foot range from elevations 537-540 feet. From about April 3 through the beginning of September each year, the reservoir is operated at MOP, the bottom foot of this range from elevation 537-538 feet, to improve juvenile fish passage through the reservoir.

B.3.3.5. Configuration and Operation for Fish Passage

Adult passage facilities. The adult fish passage facilities at Lower Monumental are composed of north and south shore fish ladders and collection systems with a common auxiliary water supply. The north shore fish ladder connects to two north shore entrances and the powerhouse collection system. The powerhouse collection system has two downstream entrances at the south end of the powerhouse and a common transportation channel. The floating orifices along the collection channel are closed. The south shore fish ladder has two downstream entrances. The auxiliary water is supplied by three turbine-driven pumps located in the powerhouse on the north side of the river. The water is pumped into a supply conduit that travels under the powerhouse collection channel, distributing water to the powerhouse diffusers, and then under the spillway to the diffusers in the south shore collection system. Excess water from the juvenile fish bypass system (approximately 200-240 cfs) is added to the auxiliary water supply system for the powerhouse collection system.

Juvenile passage facilities. The juvenile facilities consist of standard length submersible traveling screens, vertical barrier screens, 12-inch orifices, collection gallery, dewatering structure, and bypass flume to the tailrace below the project. Transportation facilities consist of a separator to sort juvenile fish by size and to separate them from adult fish, sampling facilities, raceways, office and sampling building, truck and barge loading facilities, and PIT tag detection and deflector systems.

B.3.3.6. Environmental Considerations for Retaining Turbine Units as Kaplan or Converting to Fixed Blade Units on Failure of Linkages

As discussed previously, turbine unit operating priorities are listed in the Corps' FPP. Turbine operating priorities at Lower Monumental would normally be to operate turbine unit 1 first, however they were revised due to the fixed blade status of this unit. Turbine unit 1 is not operated last on until flows are above 100 kcfs and it appears the unit can be operated continuously to meet power demands without starting and stopping. The rest of the turbine units are operated in priorities for tailrace conditions. Priorities are normally north to south, except if the project is spilling. With spill conditions, unit 5 is operated second to try to minimize eddying conditions in the tailrace. In the past, it was believed that operating unit 1 for adult passage was always required. Over time, however, this has been proven to not be required. Long periods of time without unit 1 operating at various Snake River projects have occurred due to turbine 1 failure and contracts to repair the units. No noticeable differences in passage numbers have been observed during these outages. Research conducted in the fall of 1993 and 1994 operating north powerhouse unit priority versus the normal south powerhouse priorities showed no significant passage differences. While it is still the intent to operate unit 1 at each project when available, this provides some flexibility regarding whether or not a unit has to retain Kaplan capability or if it can be converted to fixed bladed unit if there is a linkage failure.

The Corps needs to maintain the capability of operating turbine unit 1 or 2 for adult passage at all river flows, which require retaining the Kaplan configuration on one of the two turbine units. Operation of units 1 or 2 may also be required for juvenile tailrace egress at all river flows. Since unit 1 is already in a fixed blade configuration, unit 2 has to retain its Kaplan configuration. Unit 3 can be either retained in its Kaplan configuration or made into a fixed bladed unit without constraint from the configuration of the other two units. If two of the three BLH units become fixed bladed units, then the turbine unit operating priorities should be reviewed to ensure that two of the three units are operated when four units across the powerhouse operate.

B.3.4. John Day Dam

John Day has 16 BLH generators of 155 megawatt (MW) generating capacity each, with a total generating capacity of 2,480 MW. The last of the 16 generators went on line in November 1971. The north end of the powerhouse has four skeleton bays providing a potential expansion of four additional turbines. Unlike the other dams on the middle Columbia River, John Day is also operated for flood damage reduction. When high runoff is forecast, the Lake Umatilla pool is lowered to provide space for control of about 500,000 acre-feet of floodwater.

B.3.4.1. Turbine Unit Operations

Turbine unit operating priority is shown in Table B-4, including that time when synchronous condensing occurs. To the extent technically feasible, turbines will be operated within ±1% of best turbine efficiency, unless operation outside of that range is necessary to meet load requirements of the BPA administrator, consistent with the BPA System Load Shaping Guidelines, or to comply with other coordinated fish measures. The System Load Shaping Guidelines apply between April 1 and October 31. However, during the rest of the year, the project will continue to operate units within the 1% turbine efficiency range except as specifically requested by BPA for power production. From 0400 to 2000 hours during the adult migration season (March 1 - November 30), unit 1 should operate near 100 MW (±10 MW) to facilitate adult passage at the south ladder entrance. If additional load is required by BPA, unit 1 may be operated above 100 MW but should be the last to be brought up to full load and the first to drop off. Minimum powerhouse flow of approximately 50 kcfs is required March through November and 12.5 kcfs December through February. If river flow drops below about 71 kcfs, then spill may need to be less than 30% spill in order to maintain station service and power system needs.

Table B-4. Turbine Units Operating Priority for John Day Dam

Season	Time of Day	Unit Operating Priority
March 1 through November	24 hours/day	5*, 1, 2, 3, then 4 and 6-16 in any order.
December 1 through February	0600-2000 hours	5*, then unpaired units in any order
	2000-0600 hours	5*, then any unit

*Turbine unit 5 is first priority because it provides station service, some adult attraction to the south fish ladder entrance (SE-1), and some outflow past the juvenile bypass system outfall.

B.3.4.2. Operating Pool Elevation

Full pool is at elevation 268 feet and flood control pool is (minimum pool) is elevation 257 feet. From April 10 through September 30 of each year, the John Day reservoir is operated at the lowest elevation (262.5 - 264.0 feet) that continues to allow irrigation withdrawals. Slight deviations from these levels based on navigation needs, load following, and operational sensitivity may be required on occasion.

B.3.4.3. Configuration and Operation for Fish Passage

Adult fish passage facilities. The adult fish passage facilities at John Day include a north shore fish ladder that passes fish from entrances at the north end of the spillway, and a south shore fish ladder that passes fish from entrances along a collection channel which extends the full length of the powerhouse. Auxiliary water is provided to all collection systems by pumping from the tailrace. South auxiliary water also includes forebay water from the fish turbines. Counting stations are provided in both fishways.

Juvenile fish passage facilities. Juvenile fish bypass facilities, completed in 1987 with the new SMF completed in 1998, include one vertical barrier screen (VBS), STS, and one 14-inch diameter orifice per gate well in each of the project's 16 turbine units for a total of 48 orifices. The bypass collection conduit leads to a transport channel which carries collected juvenile fish to the river below the dam when the smolt monitoring facility is not in operation (bypass mode). Differential between the forebay and bypass conduit is controlled by the tainter gate, and has a criterion of 4- to 5 feet (water level in the conduit is measured at unit 16).

The juvenile bypass system operates from April 1 through December 15: April 1 - November 30 for juvenile passage and December 1 - 15 to protect adult fish that fall back through the powerhouse. From December 1 - 15 priority units will be left screened to the extent practicable (barring operational failure), and screens from non-priority units will only be removed when necessary to begin maintenance. If units are required for operation during this period, and are unscreened, they will be operated on a last on/first off basis. After December 15, all STS screens may be removed.

Potential configuration and operation changes. The Action Agencies' Biological Assessment and National Marine Fisheries Services (NMFS) Biological Opinion on the continued operation of the Federal Columbia River Power System (FCRPS) identify configuration and operation changes at John Day for the Corps to evaluate and implement, if warranted. These include surface spill, surface flow bypass, tailrace egress improvements, juvenile bypass outfall relocation, improved turbine operations for fish passage, and improvements to the north shore ladder system. Many of these improvements have the potential to change turbine operating priorities outlined in the FPP and this document. For example, a 2008 prototype test of a temporary spillway weir required turbine priorities to be shifted to 5 - 1 - 3 - 16 - 14 - 12 - 10 - 8 - 15 - 2 - 11 - 7 - 4 - 13 - 9 - 6.

B.3.4.4. Units That Could be Fixed Blade vs. Units That Should Remain Kaplan

From a fish passage perspective, turbine units 1 and 2 should remain Kaplan to be able to maintain the appropriate discharge to generate 100 MW (±10 MW) and that affords the best entrance conditions for adult salmon.

B.4.0. Water Quality Considerations

B.4.1. Total Dissolved Gas

The Corps operates a number of hydropower projects within the greater Columbia River Basin. One of the impacts of the operation of these hydropower projects is hyper-aeration of the water flowing through the dam spillways. This phenomenon can lead to gas bubble disease in fish and other biota. The extent of total dissolved gas (TDG) super saturation depends not only on the magnitude and frequency of spill, but also on the gas exchange properties at a given structure. In order to move juvenile salmon down the Snake and lower Columbia rivers in an expedient manner, and improve juvenile salmon passage and survival past dams, water is spilled through the spillway gates. Passage of juvenile salmon through the spill gates is thought to be a safer passage route as compared to passage through the turbines. Currently the Corps spills water at the four lower Columbia River and the four Lower Snake River projects as part of its implementation of the NMFS FCRPS Biological Opinion (2008) for salmonids.

If a Kaplan turbine is converted to propeller turbine, then the range of flow that a propeller turbine can pass is limited. This means that the more Kaplan turbines made into propeller in a powerhouse will limit the total flow range a powerhouse can accommodate. This could come into play during certain river flow or load demand conditions, forcing spill early and altering the ability to meet TDG standards as compared to the same conditions with all Kaplan turbines in a powerhouse.

If the TDG generated by spill exceeds a biological tolerance threshold, the benefits of spill may be negated by the development of gas bubble trauma in the fish and other aquatic biota. To prevent excessive levels of TDG to develop in the rivers, spill is managed so that the average of the 12 highest TDG levels that occur in a single calendar day does not exceed 120% in the tailwater of a project or 115% in the forebay of the next project downstream. A monitoring program has been established to effectively manage spill so that these TDG levels are not exceeded, and a Plan of Action has been outlined providing details of the overall Corps TDG monitoring program. This plan summarizes what to measure, how, where, and when to take the measurements and how to analyze and interpret the resulting data. This plan also provides for periodic review and alteration or redirection of efforts when monitoring results and/or new information from other sources justifies a change. Making a Kaplan turbine a propeller turbine may justify such a change.

B.4.2. Oil

Kaplan runners are lubricated and have the potential to leak oil into the river. Kaplan turbines converted to fixed blade units will require that the oil remain in the runner to maintain the internal components, thereby presenting the potential of oil leakage.

B.5.0. Regional Coordination

The 90% Draft Report for the Kaplan Turbine Repair Strategy was sent to the Fish Passage Operations and Maintenance (FPOM) Committee for their review and input. Written comments from committee members, as well as notes from any meetings held, are shown below. In addition, collaboration with the Turbine Survival Program (TSP) Product Delivery Team (PDT) and the Engineer Research and Development Center (ERDC) has been maintained throughout preparation of the repair strategy.

- Coordination with the region – discussions with the Fish Facility Design Review Work Group (FFDRWG) and the FPOM:
  - Presentation to FFDRWG.
  - 90% Draft for comment to FPOM.
  - Presentation to FPOM.

- Coordination with TSP PDT:
  - Available computational fluid dynamics (CFD) results will be considered.
  - ERDC bead strike analysis will be considered.
  - Sensor fish data will be considered.
  - Pertinent fish survival studies will be considered.
  - Available nadir pressure studies will be considered.

B.5.1. Regional Comments on the Repair Strategy

There were no regional comments provided on the repair strategy.

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C.1.0. Background – Existing Operation

The Kaplan Turbine Repair Strategy evaluates the feasibility of repairing a failed Kaplan turbine runner mechanism by welding or by other means fixing the turbine runner blades to a fixed position. Therefore, it is necessary to determine the optimum angle for permanently or temporarily fixing the blades. It is desirable to set the blades at an "on cam" position that provides the least risk of injury to juvenile fish passing through the turbine, without significantly compromising the mechanical integrity of the machinery or operating range of the plant. Once a Kaplan turbine runner has been modified to a "fixed blade" or propeller runner, there is only one operating point for any given head (difference in elevation between forebay and tailwater) where the performance of the runner is at its optimum; this point is referred to as on cam operation. The on cam operating curve of a Kaplan runner is made up of a series of these points as discussed in the sections below. This appendix provides background information and documents the Turbine Survival Program (TSP) Product Delivery Team's (PDT) evaluation and selection of a potential blade angle for permanently or temporarily converting a Baldwin-Lima-Hamilton (BLH) Kaplan runner to a propeller runner.

C.1.1. On Cam Operation

The term "on cam" operation relates the correct geometry of a Kaplan turbine for the existing operating head condition and the desired power out. The correct geometry is the runner blade angle and wicket gate position for an output that is optimum for operating condition requested. Optimum means using the least amount of water to achieve the desired power output. Because a typical Kaplan turbine has an operational blade rotation range of 16 degrees and wicket gate rotation range from 20 to 60 degrees, all combinations will produce power but only one combination is optimum for a selected power at a given head.

On cam blade-gate relationships are developed through performance model testing and field index testing. These tests essentially fix a runner blade angle and move the wicket gates through their rotational range, while measuring power output and relative flow. This results in the identification of the optimum point for wicket gate position and blade angle for various heads. This is repeated many times and the optimum geometry can be identified. This information is incorporated into a control system that optimally aligns the runner blade angle to wicket gate position for any desired power at any operational head. This allows for a large operating range for a Kaplan turbine.

As turbines age or operational parameters change, new on cam information must be obtained through field or laboratory testing. An example of this is the on cam operation both with and without fish screens must be separately determined because optimum geometry is different for the two conditions.

C.1.2. Off Cam Operation

The term "off cam" operation refers to operation of a Kaplan turbine at less than optimum geometry. If a Kaplan turbine (adjustable blade) is altered to remove the adjustable blade capability it would then be a simple propeller turbine or fixed blade turbine. The optimum operational range of taking such an action severely limits the operating range of such a machine. Such types of machines are typically used only where fluctuations in hydraulic head are a few feet and flow is very constant. A propeller turbine is considered to be on cam when it is operating at its most efficient point for any given head within its design range There is only one wicket gate position and power output at each head that achieves the optimum. The 1% operating range for the BLH units at the Lower Granite, Little Goose, Lower Monumental, and John Day projects will be reduced from about 9,000 cubic feet per second (cfs) to about 700 cfs if a Kaplan turbine is converted to a propeller.

Converting a Kaplan to a propeller turbine requires the selection of an optimum runner blade angle. The selection of the runner blade angle can occur anywhere in the Kaplan blade operating range. The question is then what blade angle reasonably satisfies environmental, operational and system demands.

C.2.0. Current Turbine Operating Guidelines

C.2.1. Fish Passage

The Fish Passage Plan (FPP) which is developed by the Corps with regional input establishes guidelines for the operation of the Federal Columbia River Power System (FCRPS) projects including the operation of the spillways, powerhouse, and individual turbine units. The FPP is followed by Project Operators throughout the fish passage season. The FPP requires that all turbines operate within the 1% operating range. This operating range is defined by a 1% drop in efficiency from the turbines most efficient operating point for any given head. The FPP also requires that all turbines with the exception of those at The Dalles and Bonneville 1st Powerhouse operate with fish diversion screens in place during the juvenile fish out-migration. Specific information is contained in Appendix B.

C.2.2. Site Operations

The basic powerhouse operating guidelines are shown in Table C-1 (see reference).

Project	**Forebay Elevations (feet)**		**Minimum Discharge (cfs)**		**Powerhouse Capacity (cfs)**
	Maximum	**Minimum**	**Dec-Feb**	**Mar-Nov**	
Lower Granite 1-3	746.5	733.0	0	11,500	130,000
Little Goose 1-3	646.5	633.0	0	11,500	130,000
Lower Monumental 1-3	548.3	537.0	0	11,500	130,000
John Day 1-16	276.5	257.0	12,500	50,000	322,000

Table C-1. Powerhouse Operating Guidelines

C.3.0. Assumptions

The determination of the runner blade angle used in this investigation incorporated the following hydraulic and operational assumptions.

C.3.1. Hydraulic

- The operating pool during fish passage is the minimum operating pool (MOP).
- Head is average gross head (rounded to nearest foot) with screens in for fish passage season.
- A more open geometry resulting in good wicket gate to stay vane alignment is preferred.
- Fish screens will be installed.

C.3.2. Operation

See Appendix A for specific unit parameters.

- The full operating range for a Kaplan design cannot be maintained as a propeller (fixed blade).
- Repair of low priority Kaplan turbine runners to propeller is acceptable to the region.
- The turbine operation as a propeller will reduce the operational flexibility flow range.
- A low priority turbine repaired to propeller status will be operated as a “last on/first off” unit.
- The current ratings of the existing turbines will not be exceeded.
- The Kaplan turbines will be operated in compliance with the existing fish passage plan.
- An abbreviated index test and 1% operating tables for incorporation into the FPP will be developed if a turbine is repaired to a propeller.
- Units repaired to propeller status will operate according to regionally coordinated propeller operating tables.

C.4.0. Determination of Acceptable Runner Blade Angle for Fish Passage

C.4.1. Site Hydraulics

The blade angle selected for the BLH units will be based on operations with fish screens installed and the average gross project head during the fish passage season. The average gross head was determined from the past 10 years of data while operating at MOP (Table C-2). The actual head value used in computations is rounded to the nearest foot.

Table C-2. Average Gross Head

Project	Spill Season		Fish Screens In		Average Gross Head (feet)
Lower Granite	3 April	31 August	10 April	15 Dec	99.75 (100)
Little Goose	5 April	31 August	10 April	15 Dec	95.85 (96)
Lower Monumental	7 April	31 August	10 April	15 Dec	97.96 (98)
John Day	10 April	31 August	1 April	15 Dec	102.13 (102)

C.4.2. Turbine Studies

C.4.2.1. <u>Physical Model Studies</u>

Prior to this study, observational model studies were performed at the ERDC on a representative turbine and water passage for the BLH turbine design. This model represented the 25 BLH units currently in service. Initial studies were performed by the TSP during the investigations of the repair of Lower Monumental unit 1, which had a blade mechanism failure and needed to be returned to service. The repair consisted of temporary welding the blades to the hub until a full repair could be performed. The model was used as a qualitative check on operation of the turbine as a fixed blade turbine. The final angle selected for study was 29 degrees of blade tilt. The selection of this angle was based on obtaining a good alignment of the wicket gates and stay vanes, the blades could be temporarily welded in the position selected, operation would remain within the 1% efficiency range of the existing runner, and the turbine could be synchronized to the power grid and did not exhibit abnormal cavitation, surging or rough operation. However, no quantitative information about operating range or potential effect on fish passage was obtained at that time.

The potential exists that permanent fixed blade operation may occur as part of the resulting repair strategy. It was determined by the study team that quantitative information would be necessary to assure a safe turbine operating range not detrimental to fish passage. The TSP PDT was contacted and recommended that the ERDC observational model be used to evaluate the operation of the fixed-blade runner for potential impacts to fish passage. The TSP concurred that a 29-degree blade angle offered the greatest potential to provide optimum operating condition for fish passage. This selection was based on past model investigations at ERDC, field studies and a geometric check of the stay vane to wicket gate alignment. Quantitative ERDC investigations were conducted with the runner blade angle set to a fixed 29-degree position. The turbine was operated at a 29-degree blade angle on cam and at two additional off cam conditions representative of a 1% loss of efficiency on both the low and high discharge side of the on cam point. The existing Lower Granite/John Day 1:25 scale physical hydraulic turbine model was used for this study. The model replicates all 16 turbine units at John Day and units 1-3 at Lower Granite, Little Goose, and Lower Monumental.

The ERDC model investigations were conducted with model 20-foot submerged traveling intake screens installed; operating at the prototype conditions identified in Table C-3. These conditions match those investigated by the CFD analyses (see below). The model investigations consisted of high-speed digital imaging of small neutrally buoyant plastic beads released into the flow path. The digital video was evaluated to determine the exposure of those beads to high shears zones, as well as the potential for those beads to impact structure. Laser doppler velocimeter (LDV) measurements were made to define the characteristics of flow within the turbine draft tube.

Table C-3. Prototype Operating Conditions

Operating Point	Blade Angle (degree)	Wicket Gate Rotation (degree)	Head (feet)	Discharge (cfs)
Off cam minus 1%	29	35.7	100	18,520
On cam	29	37.5	100	18,660
Off cam plus 1%	29	41.0	100	19,240

The purposes of the investigation were to: (1) verify the 29-degree blade angle selected for the BLH runner repair is not detrimental for fish passage; and (2) assure the operation of the runner off cam at a 29-degree blade angle does not increase risk of injury to fish. In general, the turbine runner with the 29-degree blade angle on cam performed very well when compared to other on cam operating positions. The turbine runner with the 29-degree blade angle, operating at the two off cam points, did not perform significantly worse than the existing turbine when operating over the 1% operating range. Operation at the low discharge side of the 1% drop in efficiency should be avoided. If the blades were welded in place at 29 degrees, the operation of the unit should be within 1% of the propeller best operating efficiency during fish passage season. The ERDC recommended that welding the blades at 29 degrees should not be considered the only solution, and investigations should be conducted at other projects with the same runner type (29 degrees may not be best at other projects) before final decisions are made for runner blade angles. The ERDC also suggested that prior to performing a permanent repair consideration be given to investigation of additional potential fish passage mitigation measures.

Figure C-1 shows the results of the LDV measurements at the draft tube exit for the flow split between the draft tube barrels. The three points represent operating the turbine at the 29-degree fixed-blade angle over the 1% range, which compares favorably with the existing Kaplan performance for the on cam point and the high discharge side of the 1% drop in efficiency. However, the low discharge side of the 1% drop in efficiency showed a significant disparity in the flow split between the two draft tube barrels. The flow split that occurred at this operating point would match a turbine loading of approximately 14,500 cfs. This indicates that the draft tube quality of flow significantly worsens at a 29-degree blade angle if operated below the low discharge side of the best operating point.

Figure C-1. LDV Measurements at Draft Tube Exit for Flow Split between Draft Tube Barrels

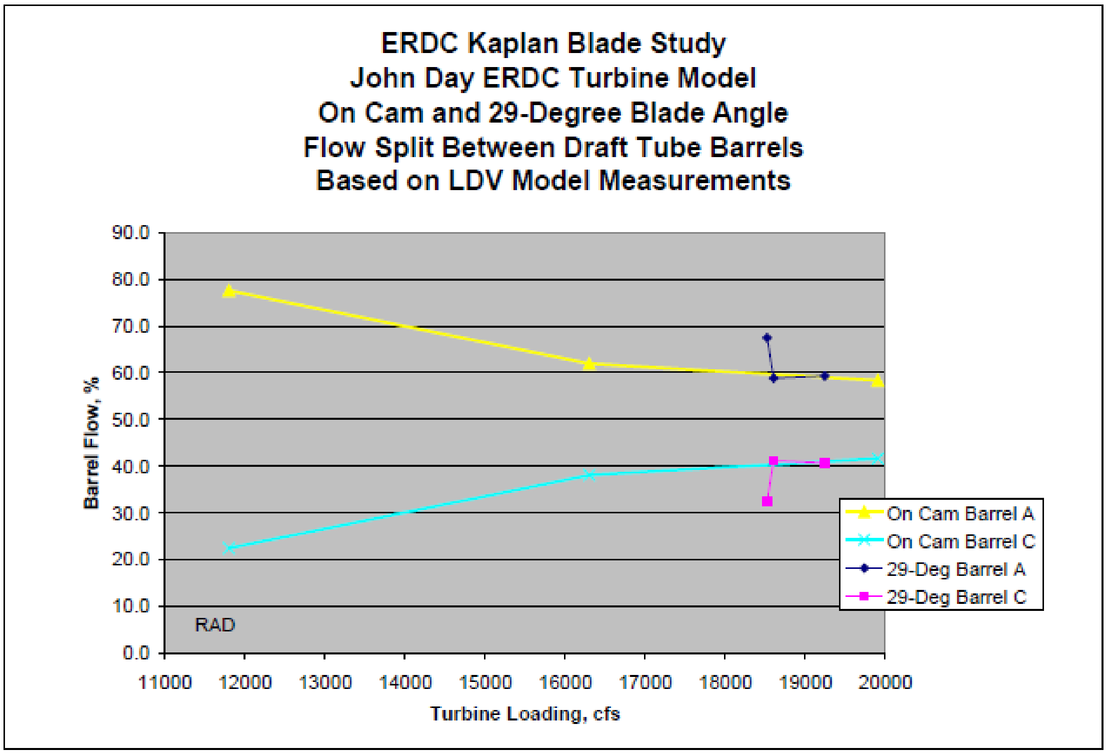


Figure C-2 shows the percent of serious bead contacts at the fixed blade angle of 29 degrees as compared to the existing Kaplan operating range. Figure C-3 shows the percentage of beads which significantly changed direction as they passed through the runner chamber while operating over the 29-degree fixed-blade angle as compared to the existing Kaplan operating range. Figure C-4 shows the stay vane severe contact score.

Figure C-2. Percent Bead Contact Score

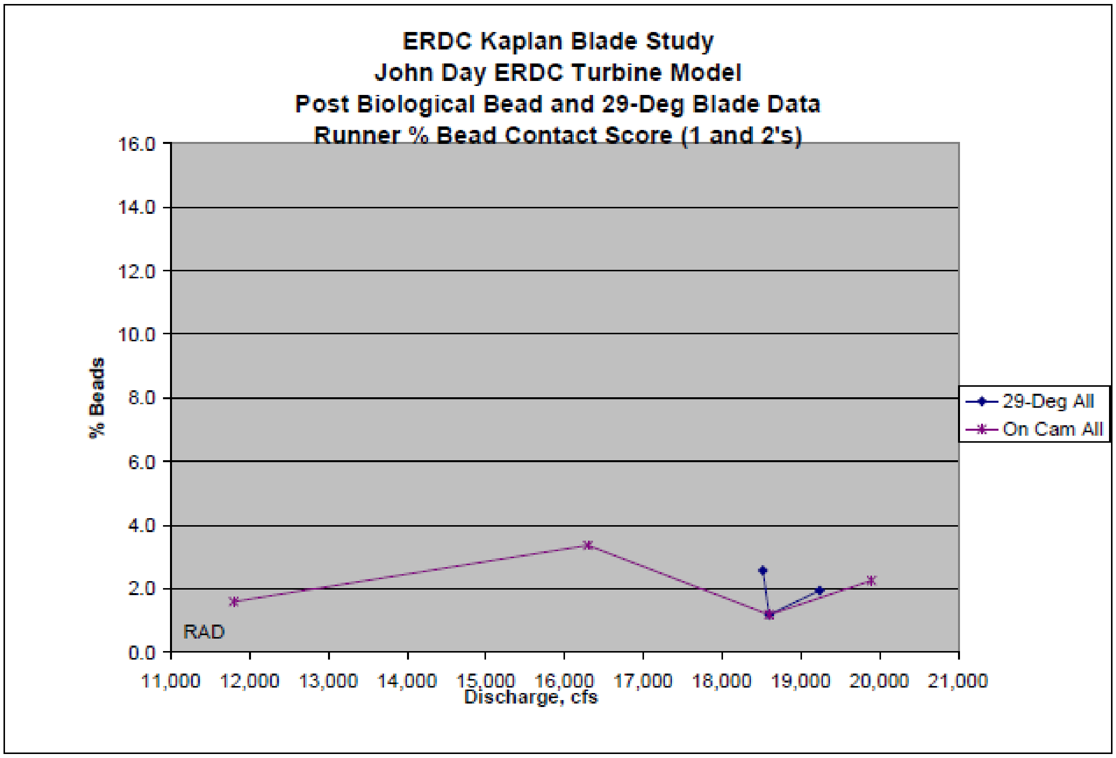


Figure C-3. Percent Bead Direction Change Score

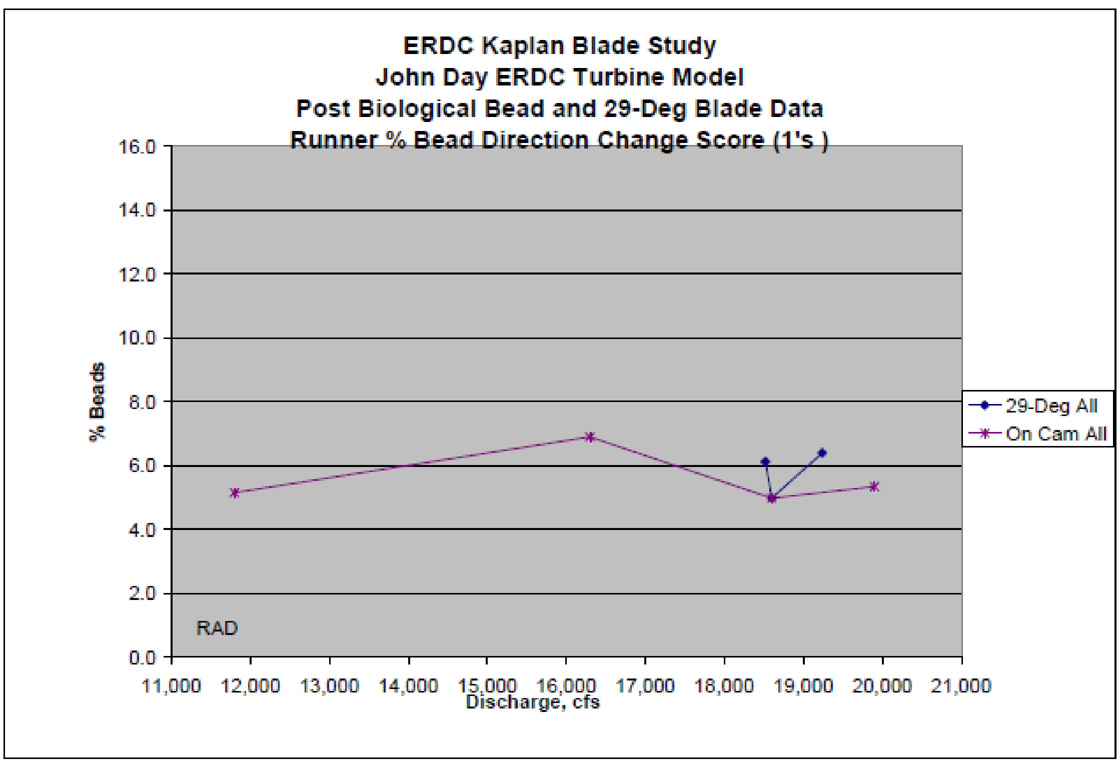
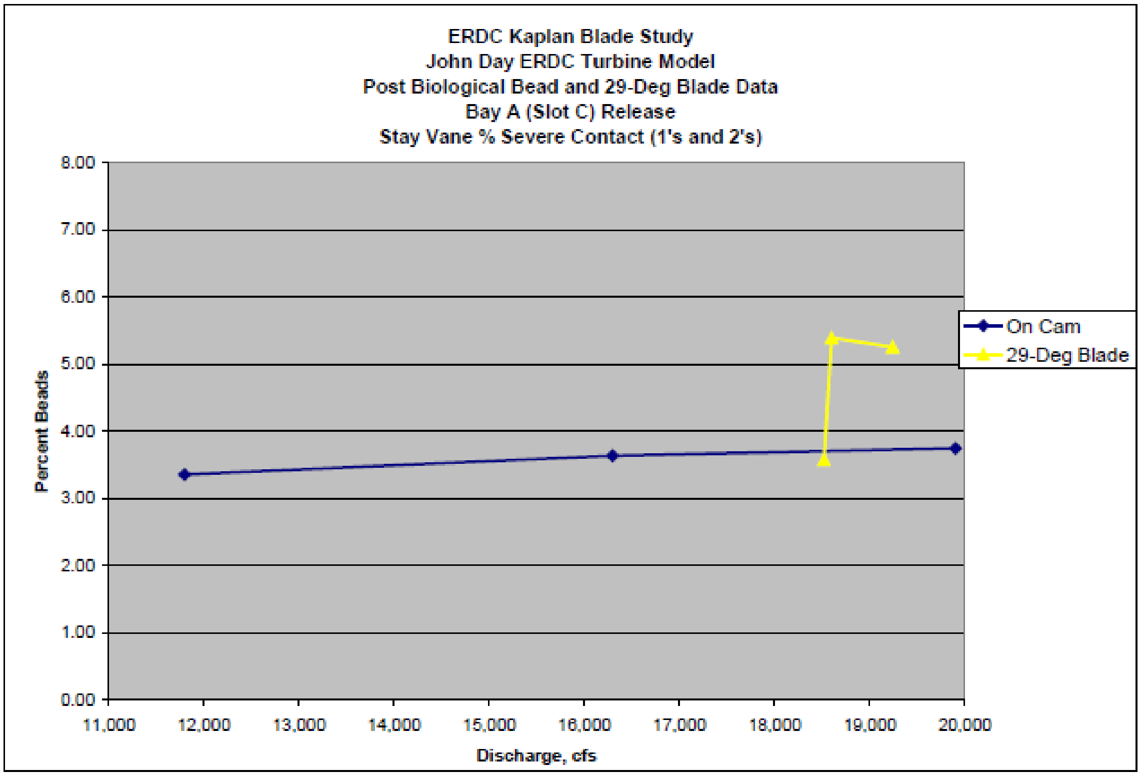


Figure C-4. Stay Vane Severe Contact Score



C.4.2.2. <u>Computational Fluid Dynamics (CFD)</u>

A CFD model of the John Day turbine was developed through the TSP to investigate pressure profiles through the turbine runner. The CFD output is necessary to conduct an evaluation of pressure related injury to juvenile fish passing through turbines. The original CFD model scope of work was expanded to include an analysis of the turbine operating at a 29-degree blade angle both on cam and at the (fixed blade) lower and upper 1% efficiency off cam points. Results of the turbine operating at the 29-degree blade angle were compared to the CFD output of the runner operated at several other on cam points within the Kaplan runner's 1% operating range. Figures C-5 and C-6 display the computational domain of the CFD analysis.

The results of the CFD analysis for the 29-degree blade angle, (fixed blade) 1% operating limit are shown in Figure C-7. The CFD predicts no significant nadir difference between the three operating conditions. Any added risk of pressure related injury to juvenile fish by operating the runner at a 29-degree blade angle as a "fixed blade" would appear to be very low.

Figure C-5. CFD Computational Domain for Intake

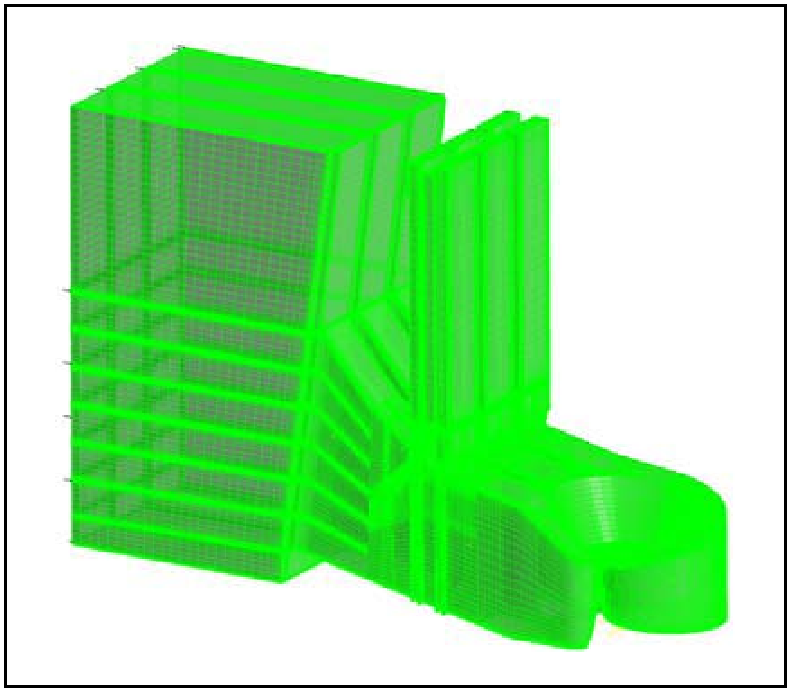


Figure C-6. CFD Computational Domain for Turbine

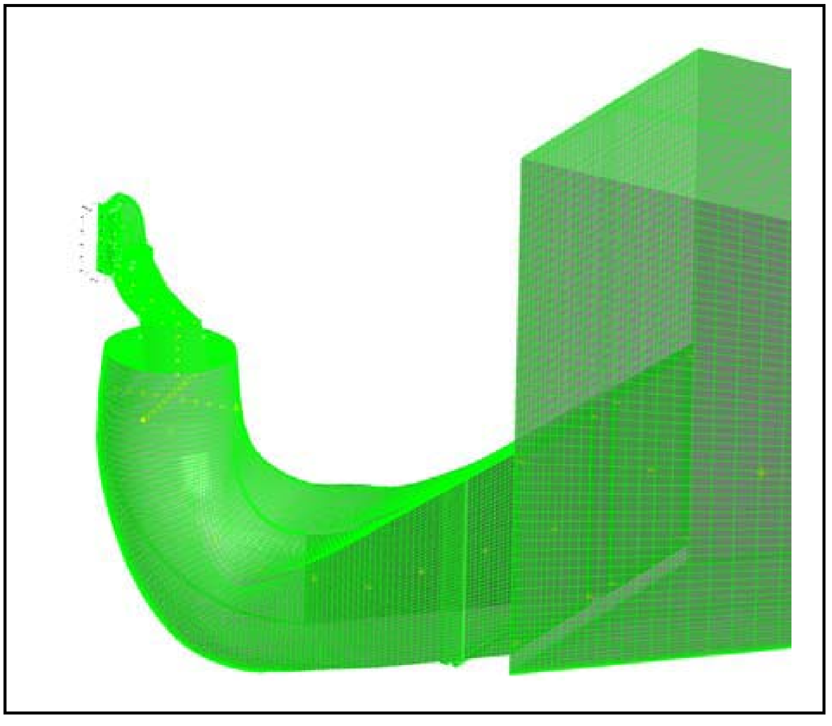
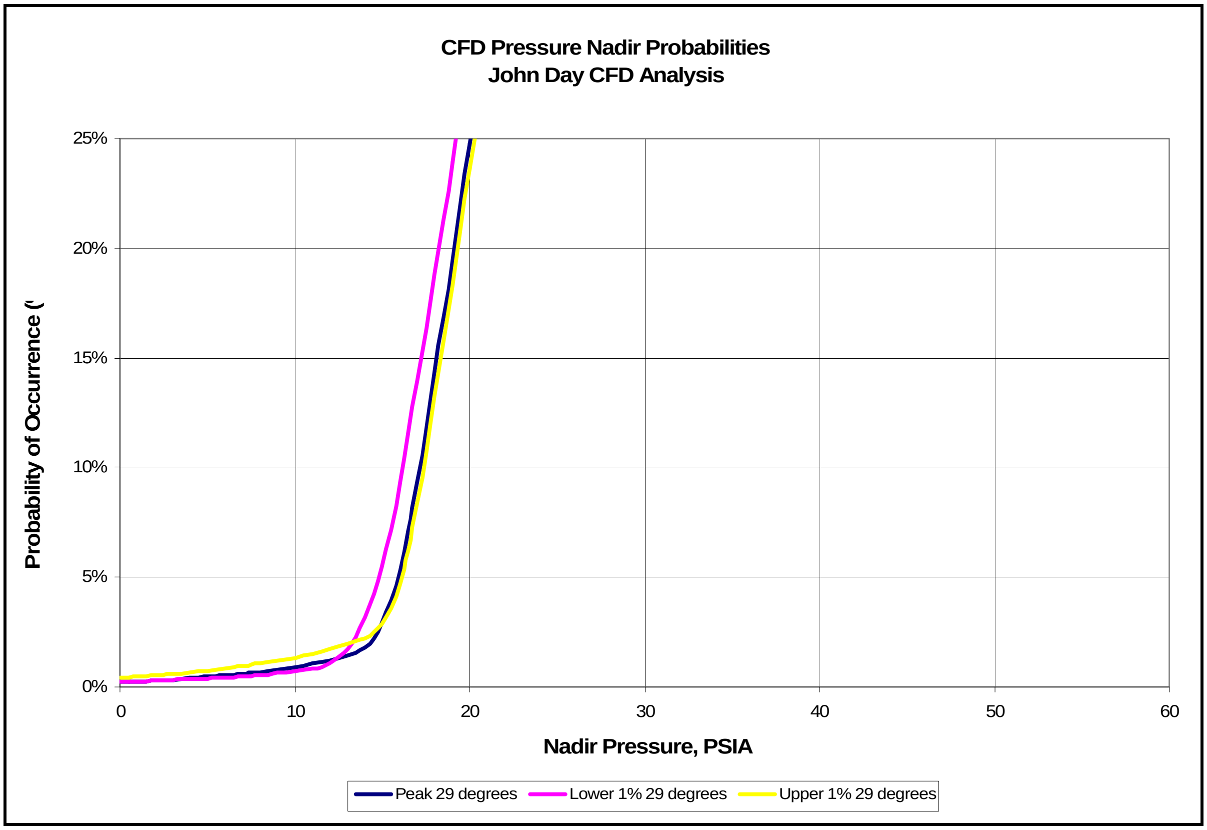


Figure C-7. Results of CFD for Three Operating Conditions at 29-degree Blade Angle



C.4.2.3. Turbine Geometry

Recent field studies of the McNary and John Day turbines indicate a higher probability of survival for juvenile Chinook salmon when passing through a turbine operated with a "more open geometry" (Normandeau 2003, 2007) beyond the current upper 1% operating limit. The turbine unit has an open geometry when the wicket gates are well aligned with the stay-vanes and the runner blades are at a steep rather than flat angle. This provides for a uniform flow through the runner and minimizes exposure to impact, shear, and turbulence. However, the referenced field tests did not account for pressure related injuries. The geometry for turbine operation (runner blade position and wicket gate position) is represented in a family of curves called an "on cam diagram." For example, Figure C-8 illustrates a family of on cam curves over the head range of 105 to 90 feet at John Day. Superimposed on the curves is a horizontal line drawn at 29 degrees illustrating the effect of a Kaplan turbine runner operating at a single blade position. Over the operating head range, the wicket gate position for best operating point varies from about 37 to 41.5 degrees. Figures C-9, C-10, and C-11 show the geometric position of the wicket gates in relation to the stay vanes and scroll case.

When repaired to a propeller at a 29-degree blade angle, the wicket gate operating range is restricted to 37.5 degrees near best operating point (Figure C-9), 35.7 degrees near lower 1% (Figure C-10), and 41 degrees near upper 1% limit (Figure C-11). It should be noted that the full open design wicket gate opening of 52 degrees is rarely reached because the electrical limit of these units is reached at much less wicket gate openings (approximately 40 to 45 degrees).

Figure C-8. Cam Curves and Wicket Gate Operating Range

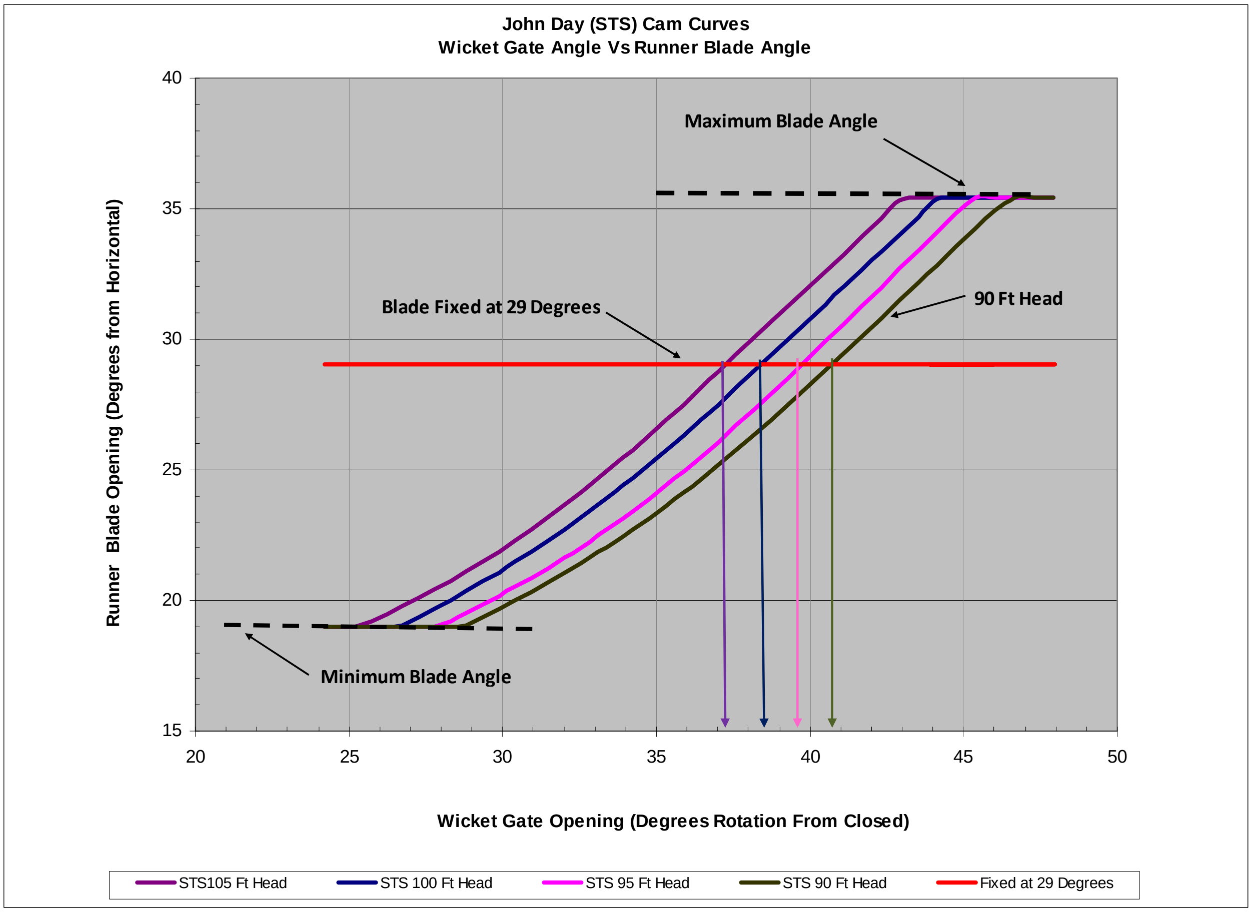


Figure C-9. Wicket Gate at 37.5 Degrees near Best Operating Point at 29-degree Blade Angle

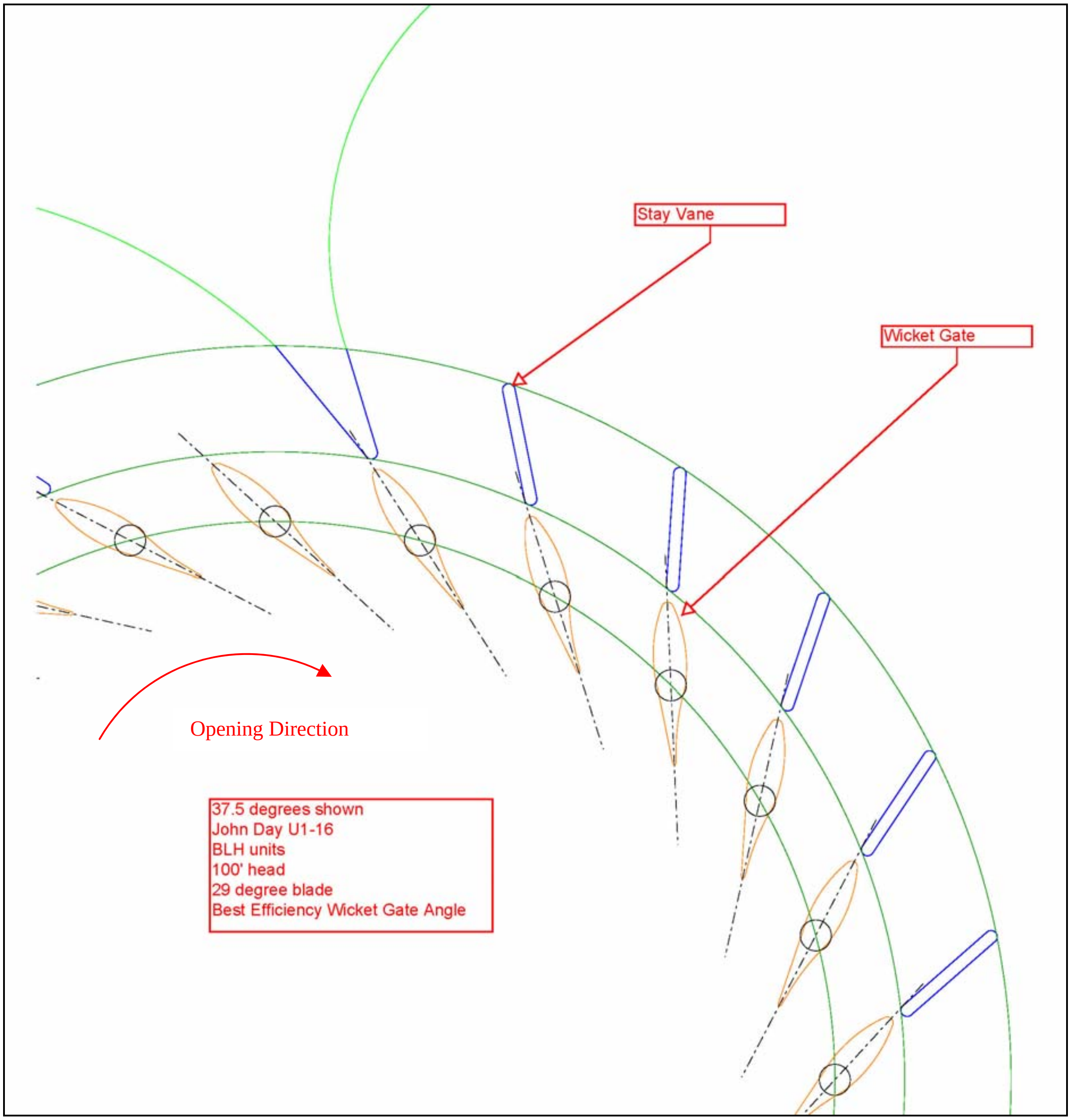


Figure C-10. Wicket Gate at 35.7 Degrees near Lower 1% Limit at 29-degree Blade Angle

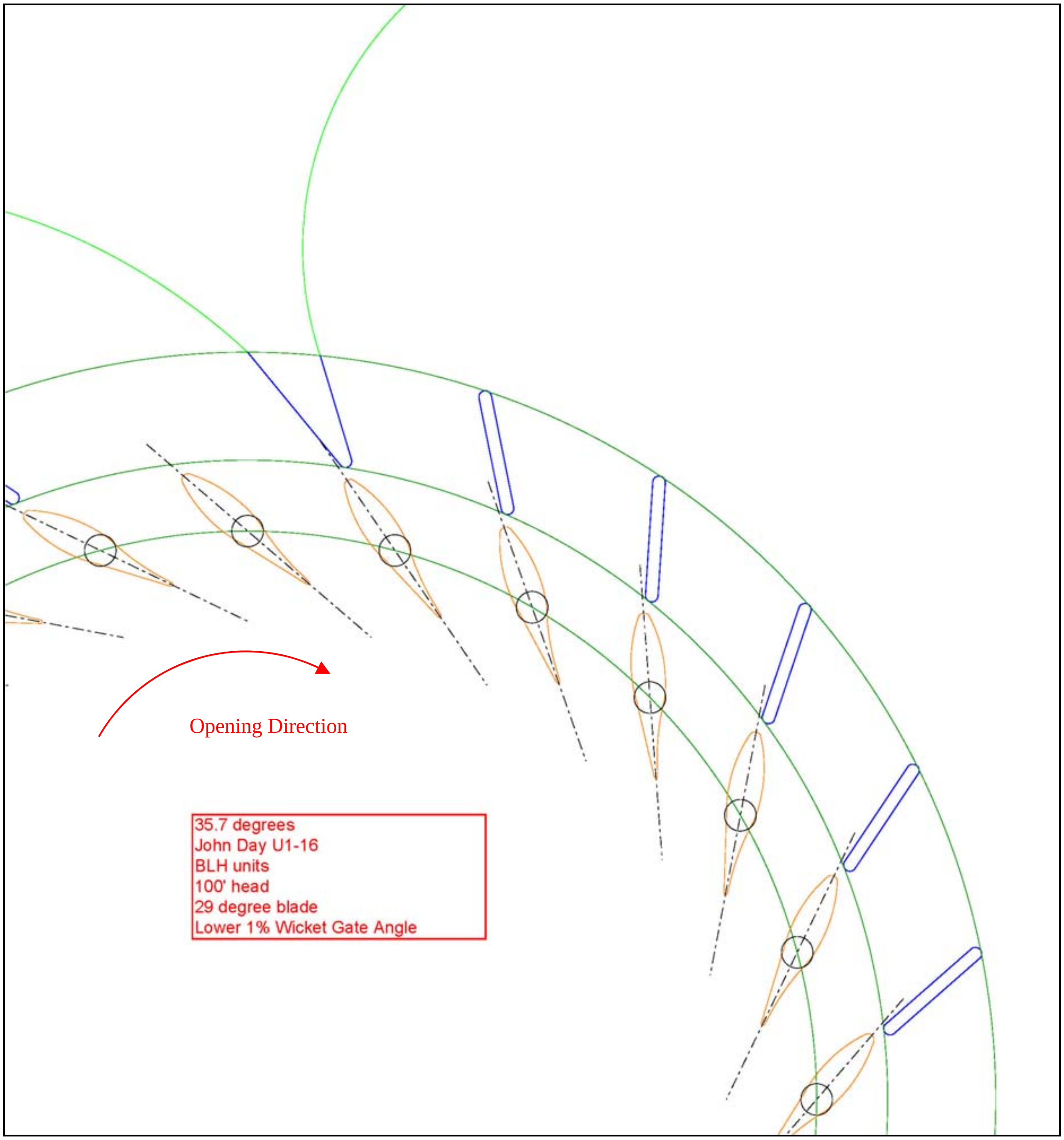


Figure C-11. Wicket Gate at 41 Degrees near Upper 1% Limit at 29-degree Blade Angle

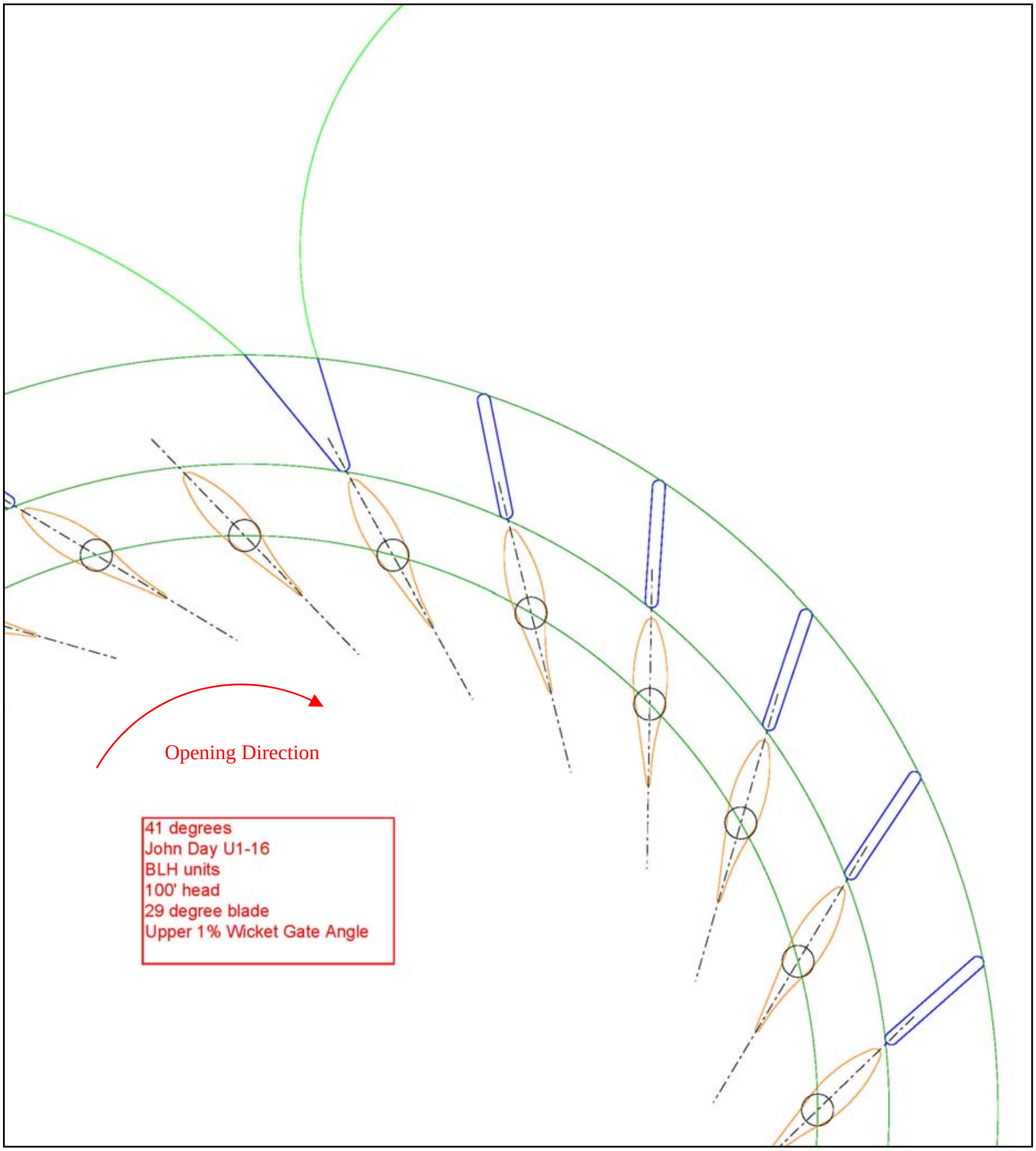
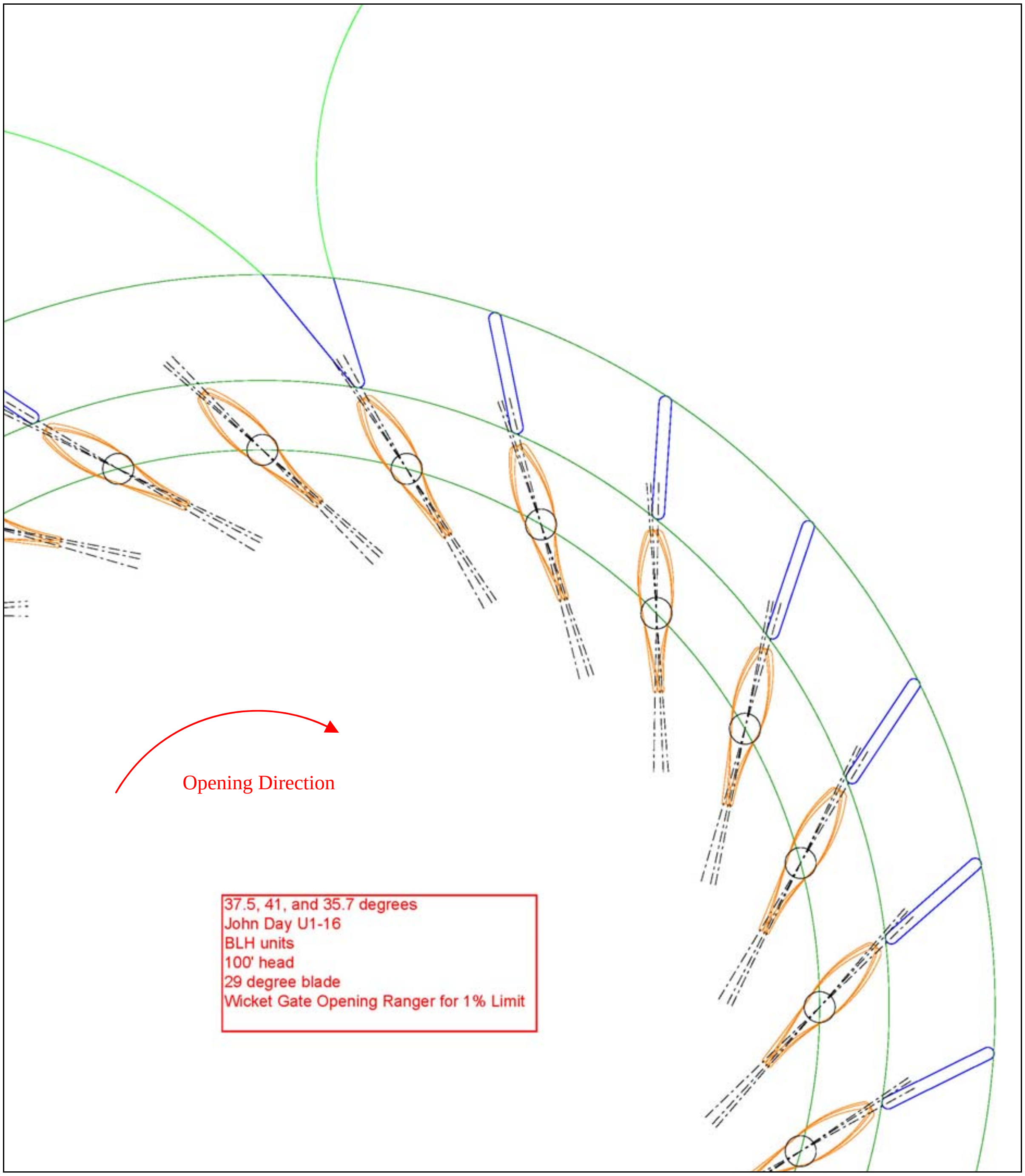


Figure C-12 shows the geometric operating range of the wicket gates for a blade angle of 29 degrees. The operating range of the wicket gates is about 5 degrees of rotation. The positions show a very good geometric relationship while maintaining a reasonable total flow capability with limited operational flexibility.

Figure C-12. Wicket Gate Operating Range for 1% Limits



C.4.3. Biological Field Studies

C.4.3.1. <u>Turbine Survival Studies</u>

A biological field test at John Day (Normandeau 2007) investigated turbine operation of John Day BLH unit 9. The test was designed to estimate survival probabilities of hatchery-reared Chinook salmon passing through the turbine operating at three conditions corresponding to the lower end, peak, and upper limit of the 1 % operating range (Table C-4). The testing was performed by Normandeau using Hi-Z balloon tag methods; in addition to live fish, a series of sensor fish (an instrument package used to record pressure and acceleration in a time history) were released during the test period. There were three release locations for each of the three turbine operating conditions investigated. The results of the Hi-Z tests are discussed below for releases in the three individual intake bays. Estimated 48-hour survival probabilities and standard errors (parentheses) for the three turbine operations (slots combined) are shown in Table C-4. The highest survival (0.959) coincided with the most open geometry, occurring at the upper 1% limit.

Table C-4. 48-hour Survival Estimates for Three Operating Conditions at John Day (slot passage survival estimates combined)

Lower 1% Efficiency (11.8 kcfs)	Peak Efficiency (16.6 kcfs)	Upper 1% Efficiency - Best Geometry (19.9 kcfs)
0949 (0.010)	0.93 (0.011)	0.959 (0.009)

Note: kcfs = thousand cubic feet per second; standard error (SE) in parentheses

The 48-hour survival estimates for each of the nine test conditions are shown in Table C-5.

Table C-5. 48-hour Survival Estimates for All Test Conditions at John Day

Turbine Slot	Lower 1% Efficiency (11.8 kcfs)	Peak Efficiency (16.6 kcfs)	Upper 1% Efficiency (19.9 kcfs)
Slot A	0.979 (0.011)	0.939 (0.020)	0.977 (0.013)
Slot B	0.931 (0.019)	0.930 (0.019)	0.940 (0.019)
Slot C	0.935 (0.020)	0.932 (0.020)	0.959 (0.015)

Note: kcfs = thousand cubic feet per second; standard error (SE) in parentheses

All survival probabilities equaled or exceeded 0.930 with the lowest survival (0.930, SE = 0.019) occurring for fish passed through Slot B at 16.6 kcfs (peak efficiency). The highest survival (0.979, SE = 0.011) occurred when fish were passed through Slot A at 11.8 kcfs (lower 1% efficiency).

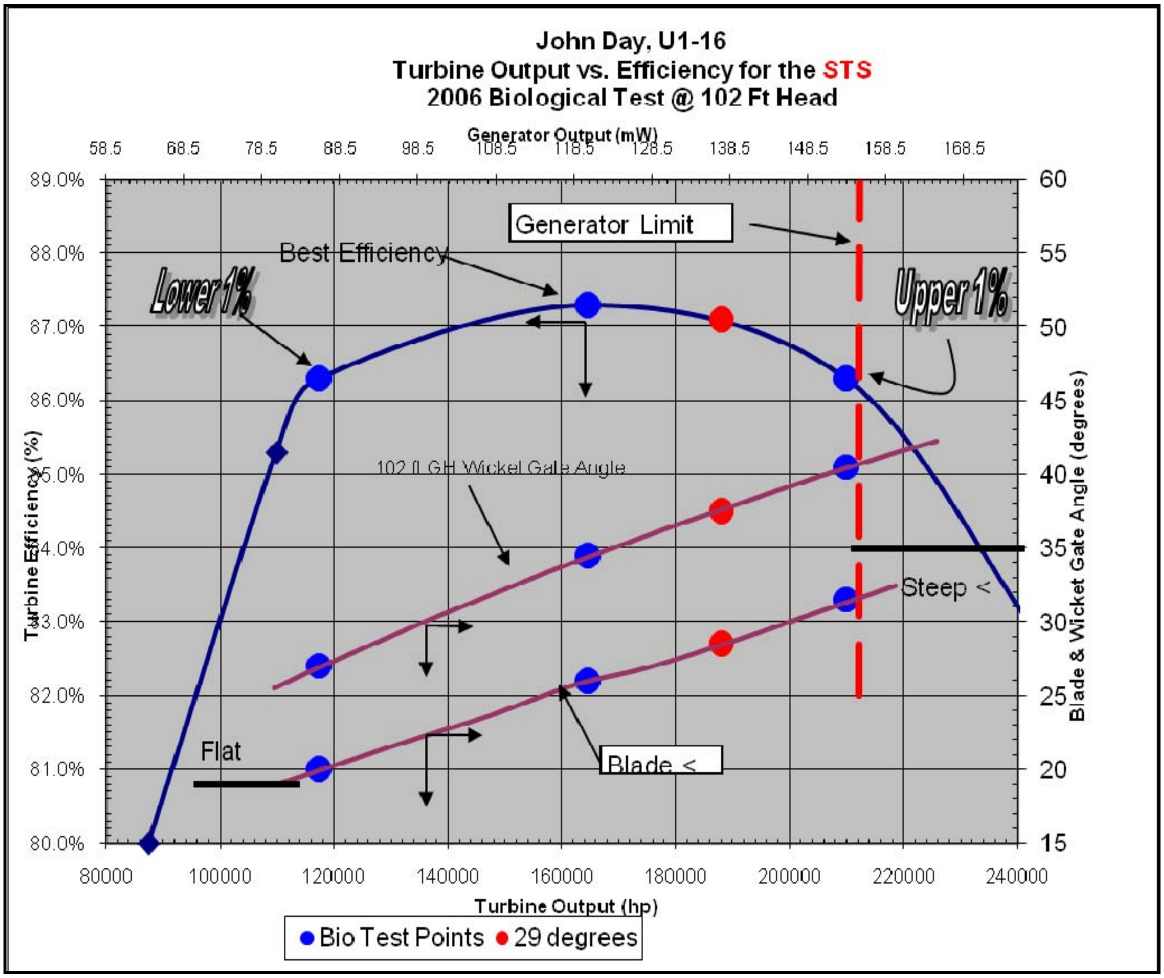
Average “clean fish estimate” (CFE), which includes all examined fish without injuries or maladies, was also calculated for each treatment scenario. The CFE does not account for those test fish that were released into the turbine but not retrieved. The CFE probabilities and SE (in parentheses) for the three turbine geometries (slots combined) are shown in Table C-6.

Table C-6. Clean Fish Estimates for Three Operating Conditions at John Day

Lower 1% Efficiency (11.8 kcfs)	Peak Efficiency (16.6 kcfs)	Upper 1% Efficiency - Best Geometry (19.9 kcfs)
0.962 (0.008)	0.971 (0.007)	0.983 (0.006)

Figure C-13 shows the test conditions at which the John Day turbine survival test was performed. The blue circles indicate the survival test conditions related to the geometry of the turbine. The red circles indicate turbine operation with a 29-degree blade angle.

Figure C-13. Test Conditions for Biological Testing at John Day



C.4.3.2. Turbine Pressure Investigations

Previous studies have indicated that the low pressure domain occurring during turbine passage was insignificant for mortality or injury for surface acclimatized smolt turbine passage. Further research indicated that depth acclimatization had not been adequately addressed. Since, air in the swim bladder expands and compresses within the air bladder with changing depth, an element of pressure effects on fish passage had been overlooked. Additional laboratory biological investigations recommended by the TSP were performed by the Pacific Northwest National Laboratory (PNNL). The PNNL conducted a series of laboratory investigations to evaluate effects of turbine pressure on neutrally buoyant, depth acclimated yearling and sub-yearling Chinook salmon (PNNL 2008). The study resulted in development of probability estimates of mortal injury to depth acclimated fish exposed to a range of turbine nadir pressures (the lowest pressure point for any flow path, i.e., the lowest point within a pressure profile). Although the study was designed to estimate the probability of mortal injury as a function of acclimation depth, nadir pressure, maximum pressure rate of change, and total dissolved gas concentration of the acclimated water, the primary factors contributing to mortal injury were acclimation depth and nadir pressure.

An example of this relationship is shown in Figure C-14. This preliminary figure shows the expected mortality derived from the PNNL testing. Although this work is not yet finalized, some information about the dangerous range of turbine pressure nadirs can be identified. It appears that nadir pressures 10 pounds per square inch absolute (psia; absolute means that the indicated pressure is referenced to a vacuum) and below can be harmful to fish passing through a turbine runner. However, the depth of acclimatization and the rate of change of pressure can influence the effect on fish passage.

Figure C-15 is a summary of preliminary results of the PNNL laboratory pressure studies. This figure is thought to be a worst case scenario and includes the rate of change of pressure through the turbine runner at the highest acclimation pressure measured. Although worst case, nadir pressures in the 10-12 psia range and below can be assumed as dangerous until more information becomes available.

Figure C-14. Expected Mortality vs. Turbine Nadir Pressure at 25-foot Depth Acclimatization

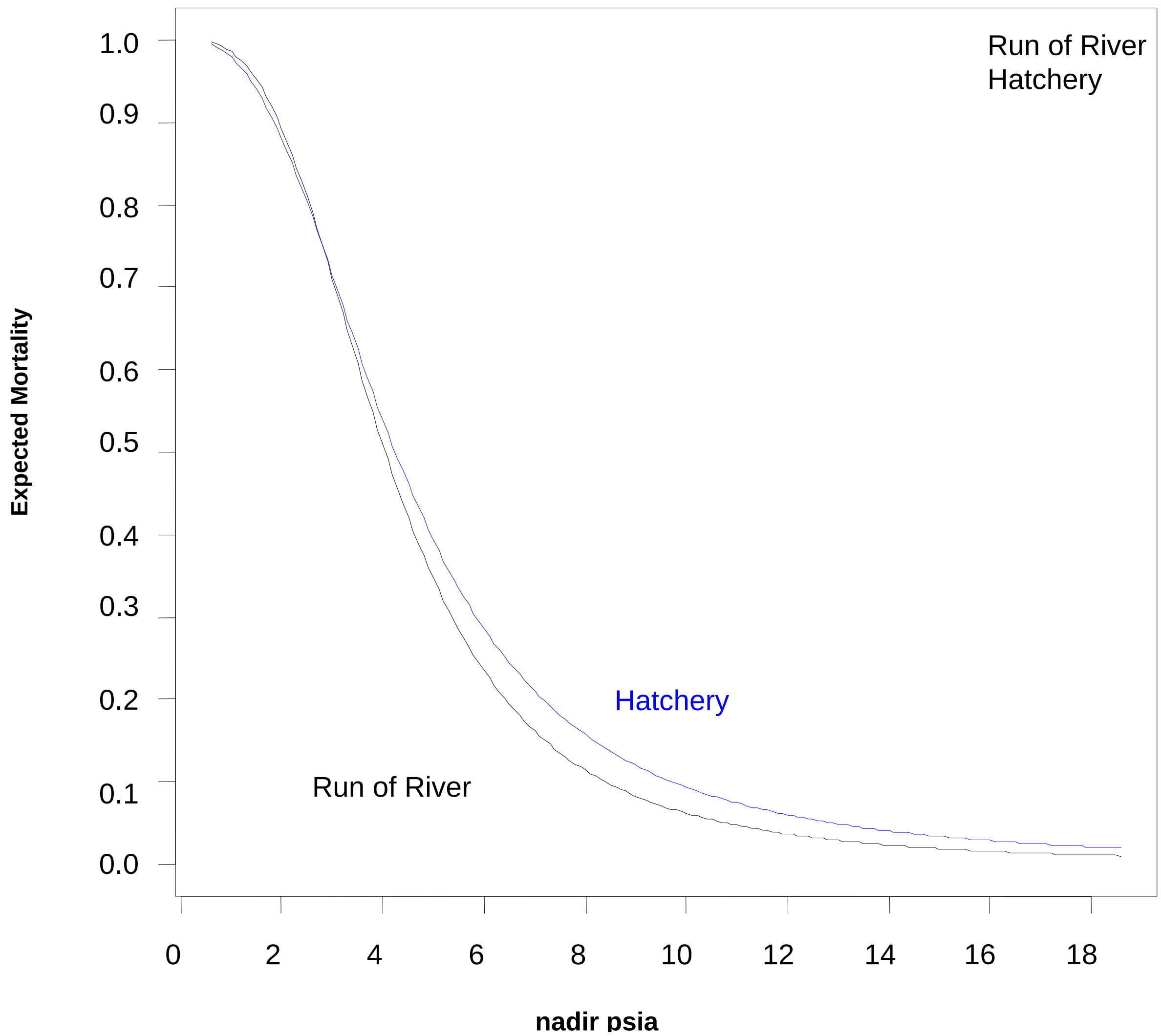
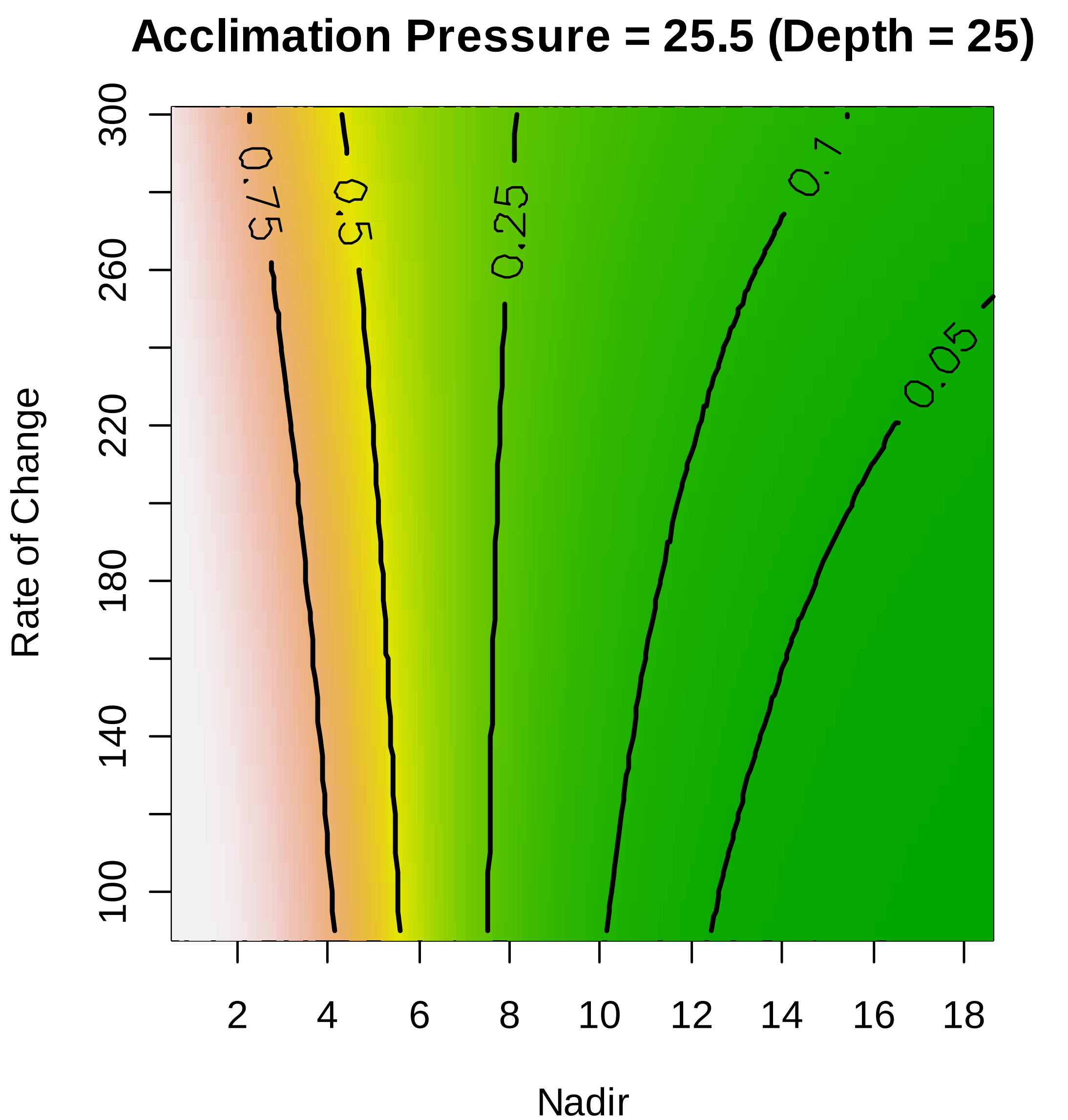


Figure C-15. Apparent Worst Case Mortality vs. Pressure Nadir

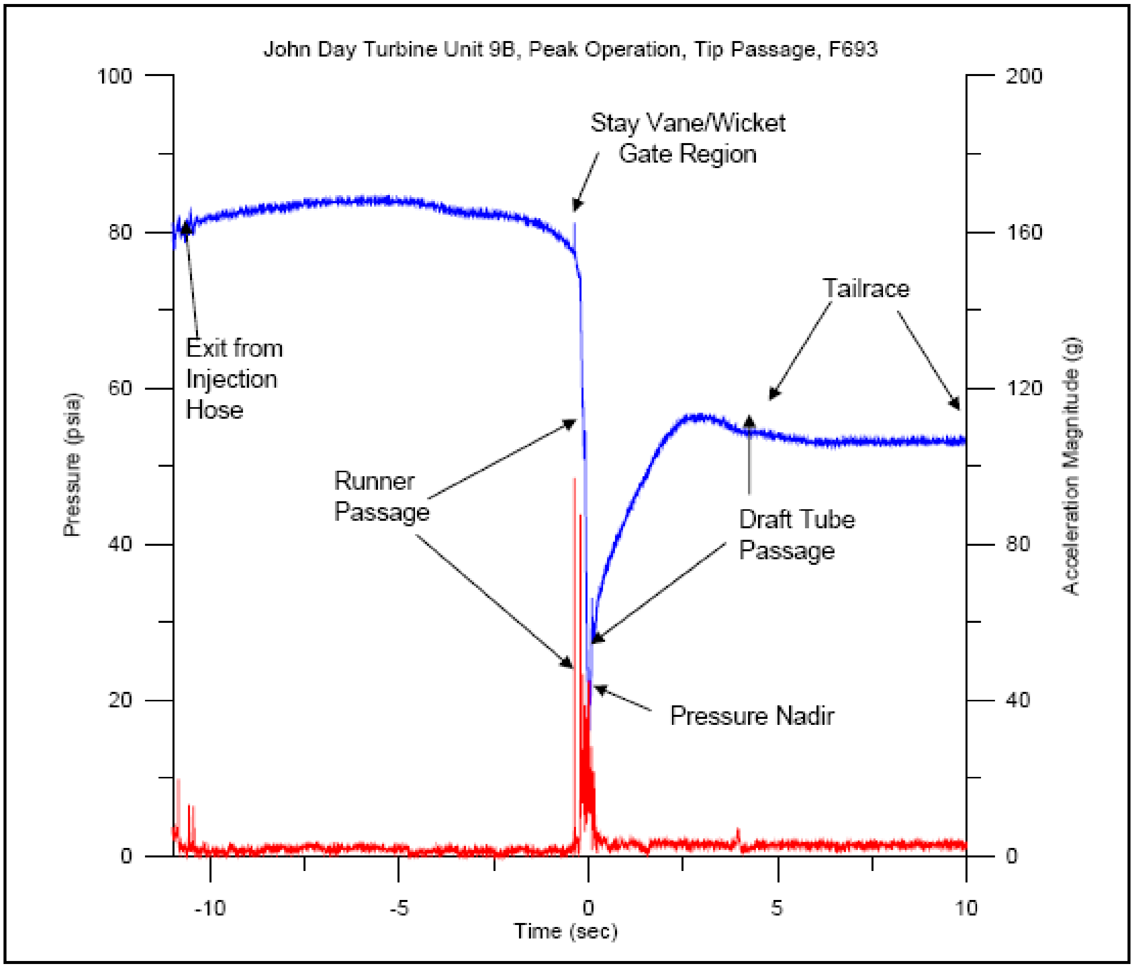


C.4.3.3. <u>Sensor Fish</u>

The sensor fish is an instrument package used to record pressure and acceleration in a time history while passing through a selected flow domain. Sensor fish were used during the John Day turbine passage biological testing. The information available on the sensor fish is contained in the PNNL report (2008). Sensor fish information was obtained at best efficiency and the upper 1% operating limit while operating on cam as a Kaplan turbine. Figure C-16 is a typical sensor fish trace of turbine passage from intake through tailrace.

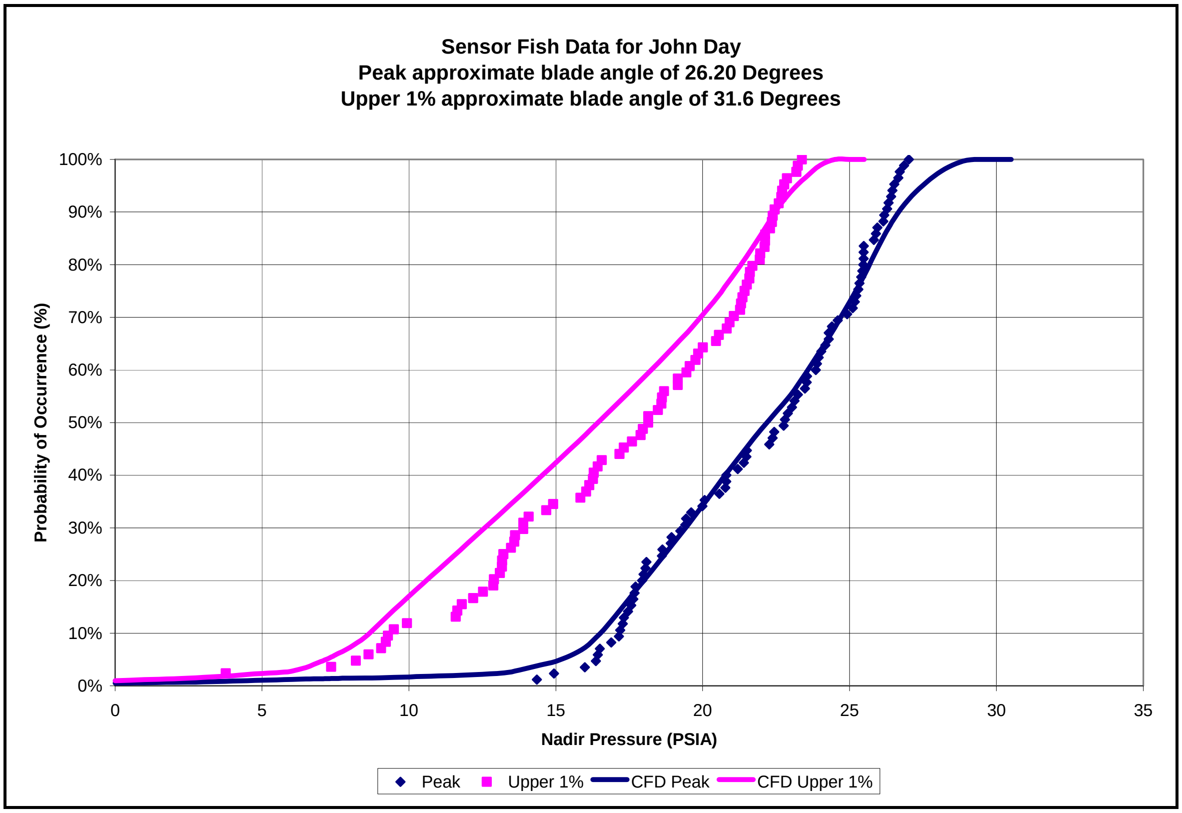
Figure C-16. Sample of Pressure and Acceleration Magnitude Time Histories

A sensor fish device was used at John Day turbine unit 9, intake slot B, for peak efficiency operation and runner tip passage route. A collision event that occurred during passage through the vane/wicket gate region is shown below where red represents acceleration magnitude and blue is absolute pressure.



The John Day sensor fish data was compiled into a probability of occurrence versus pressure nadir (Figure C-17). Although the amount of data available is not sufficient to be statistically valid, it is the only prototype data available identifying the pressure nadir of the BLH turbines considered in this study. It appears that nadir pressures of about 7.0 psia occurred in about 5% of samples at the upper 1% operating limit.

Figure C-17. Sensor Fish Nadir Pressure vs. Probability of Occurrence



Biological data has not been collected for a 29-degree blade angle but the peak (~26.2 degrees) and the upper 1% (~31.6 degrees) is shown in Figure C-17. The recommended CFD results are also shown in the figure. For the peak condition, the sensor fish and CFD results match very closely for the upper 1% condition; the CFD results are more severe when compared to the sensor fish data.

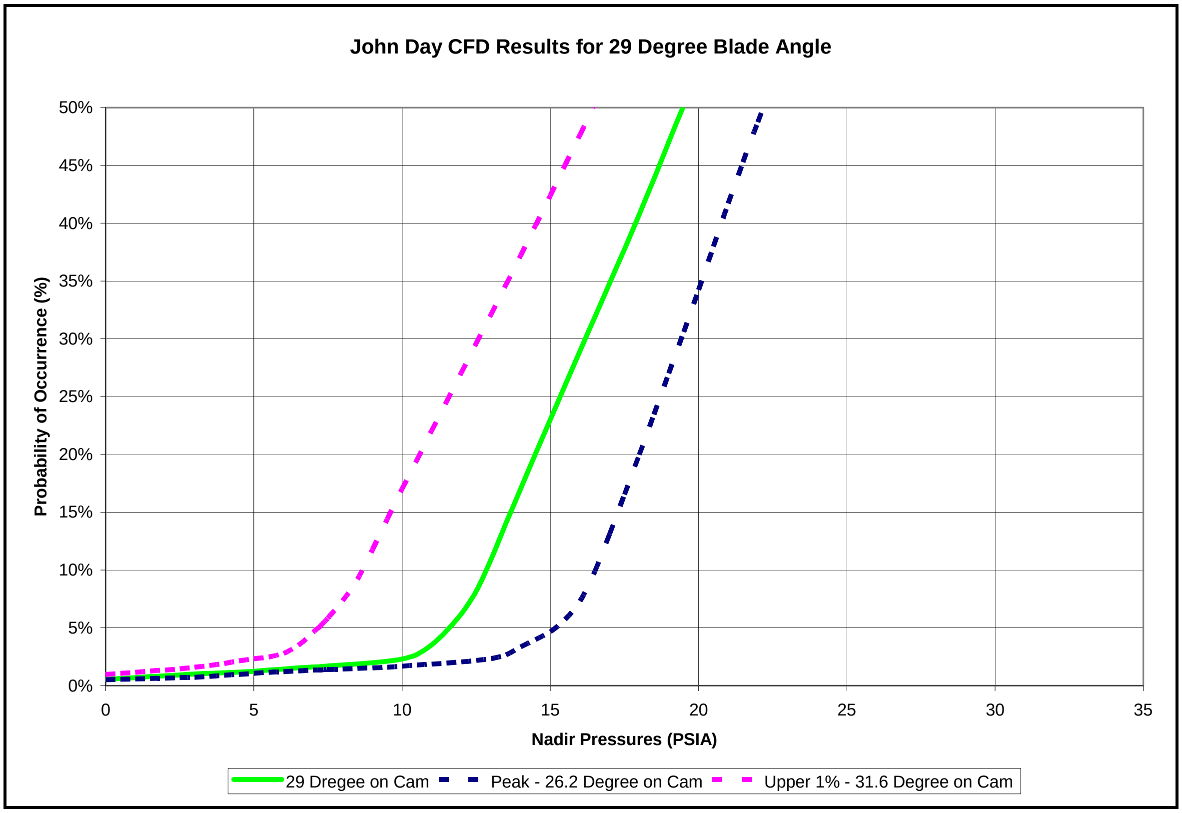
C.4.4. Selection of Blade Angle

The selection of a 29-degree blade angle appears satisfactory for this study.

1. The results of the John Day biological test indicate the best turbine biological operating area is near a 29-degree blade angle.
2. Given some uncertainty, nadir pressures appear satisfactory at 29-degree operating condition (see Figure C-18).
3. The geometry of the unit appears satisfactory.
4. The best operating efficiency at 29 degrees is within the existing Kaplan 1% limits.

Figure C-18 shows the CFD results for the 29-degree blade angle; the sensor fish results at peak and upper 1% results are shown for reference.

Figure C-18. Comparison of Sensor Fish Data and CFD Predictions



C.5.0. Turbine Performance as a Propeller

A 2006 turbine field test on Lower Monumental unit 1 was performed to confirm operational parameters were satisfactory and to establish operating limits conforming to regional fish passage requirements (HDC 2006). The field testing was completed satisfactorily and forms a basis for computing the predicted turbine performance for the other sites containing the BLH turbines under study (Figures C-19 to C-22).

Figure C-19. Lower Granite with Extended Length Submerged Bar Screens (ESBS)

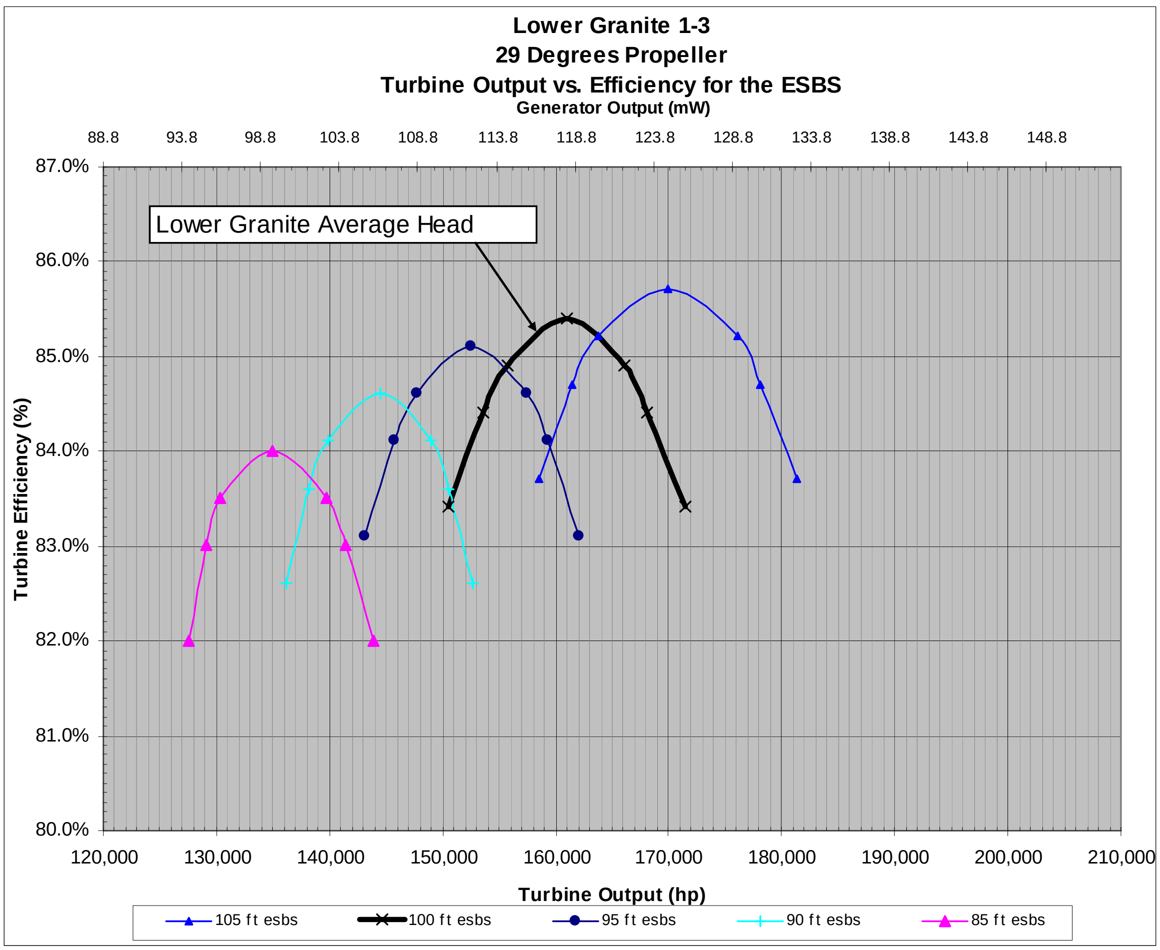


Figure C-19 (continued). Lower Granite with Extended Length Submerged Bar Screens (ESBS)

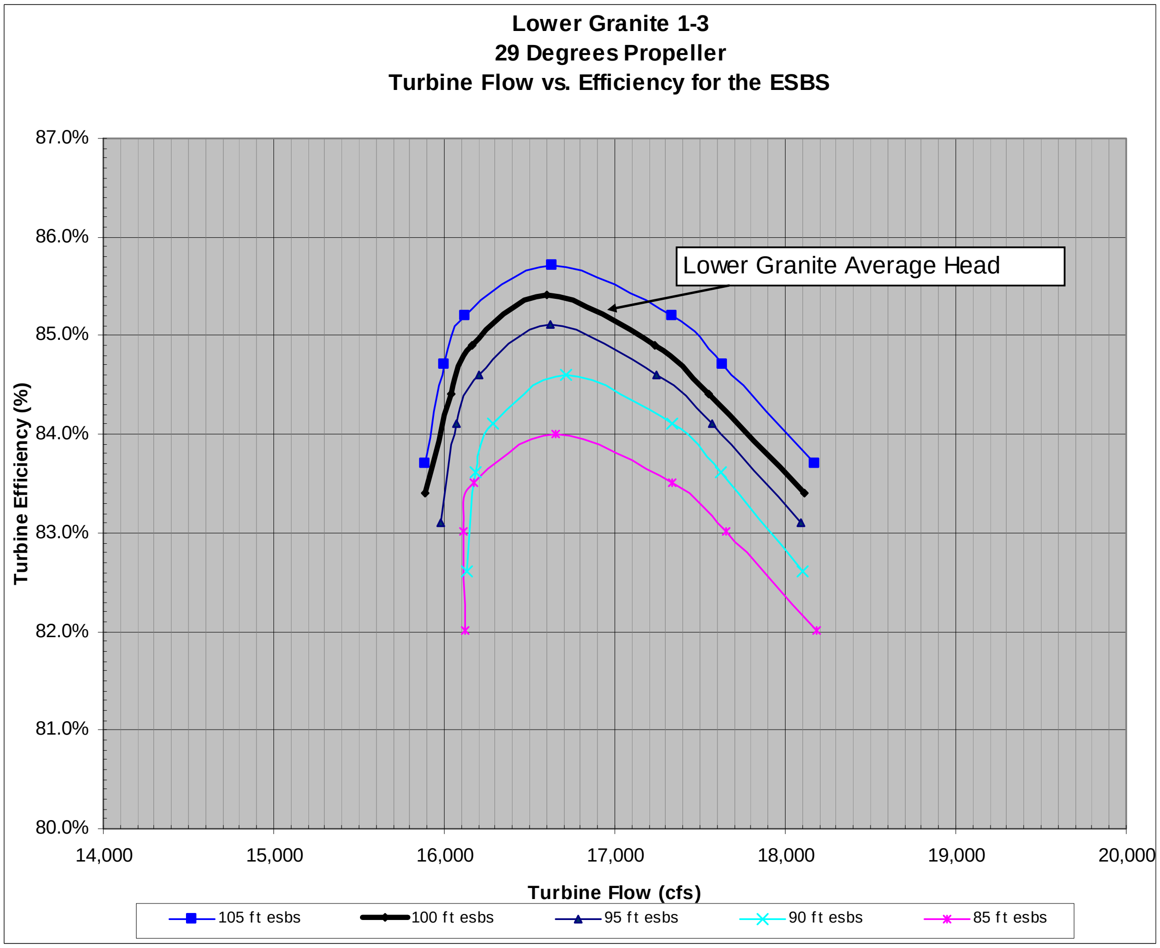


Figure C-20. Little Goose Units 1-3 with ESBS

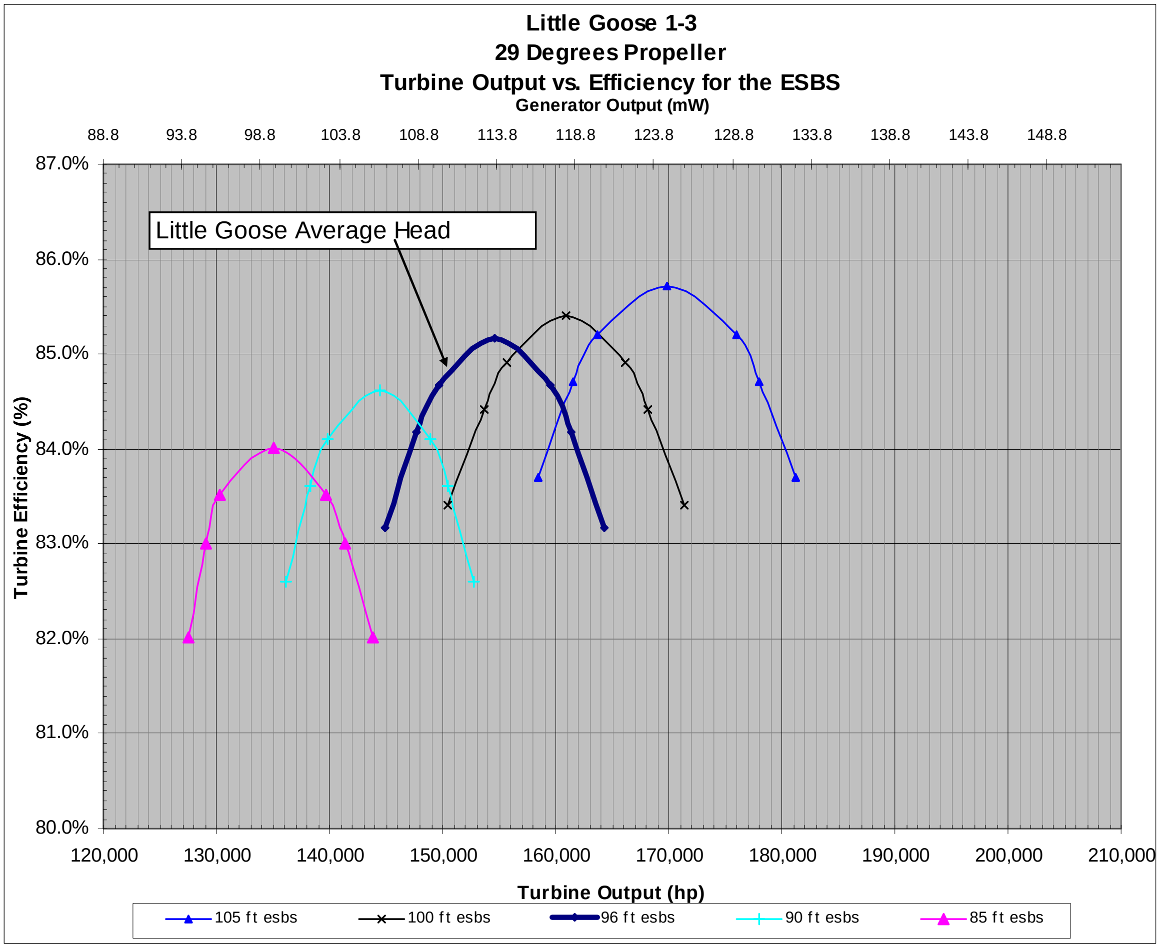


Figure C-20 (continued). Little Goose Units 1-3 with ESBS

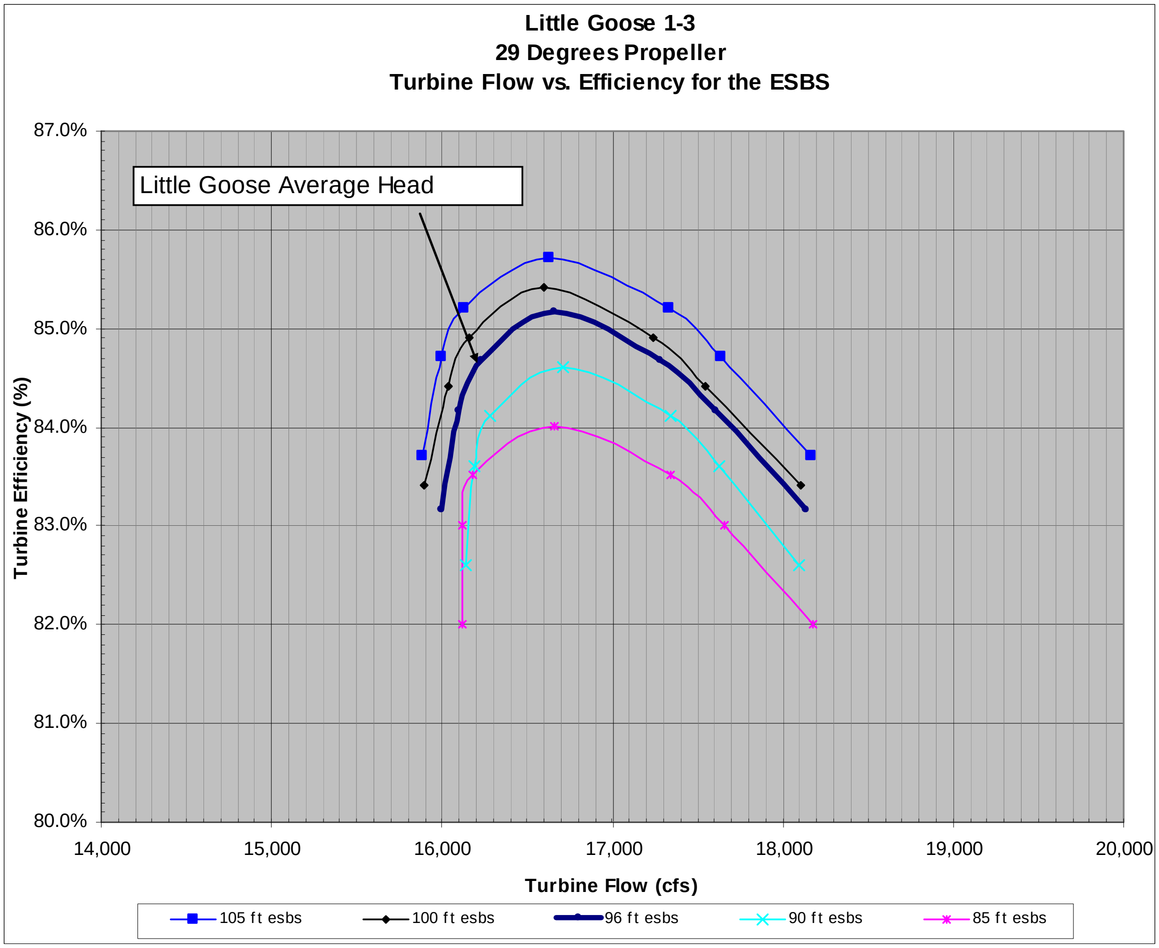


Figure C-21. Lower Monumental Units 1-3 with Submersible Traveling Screens (STS)

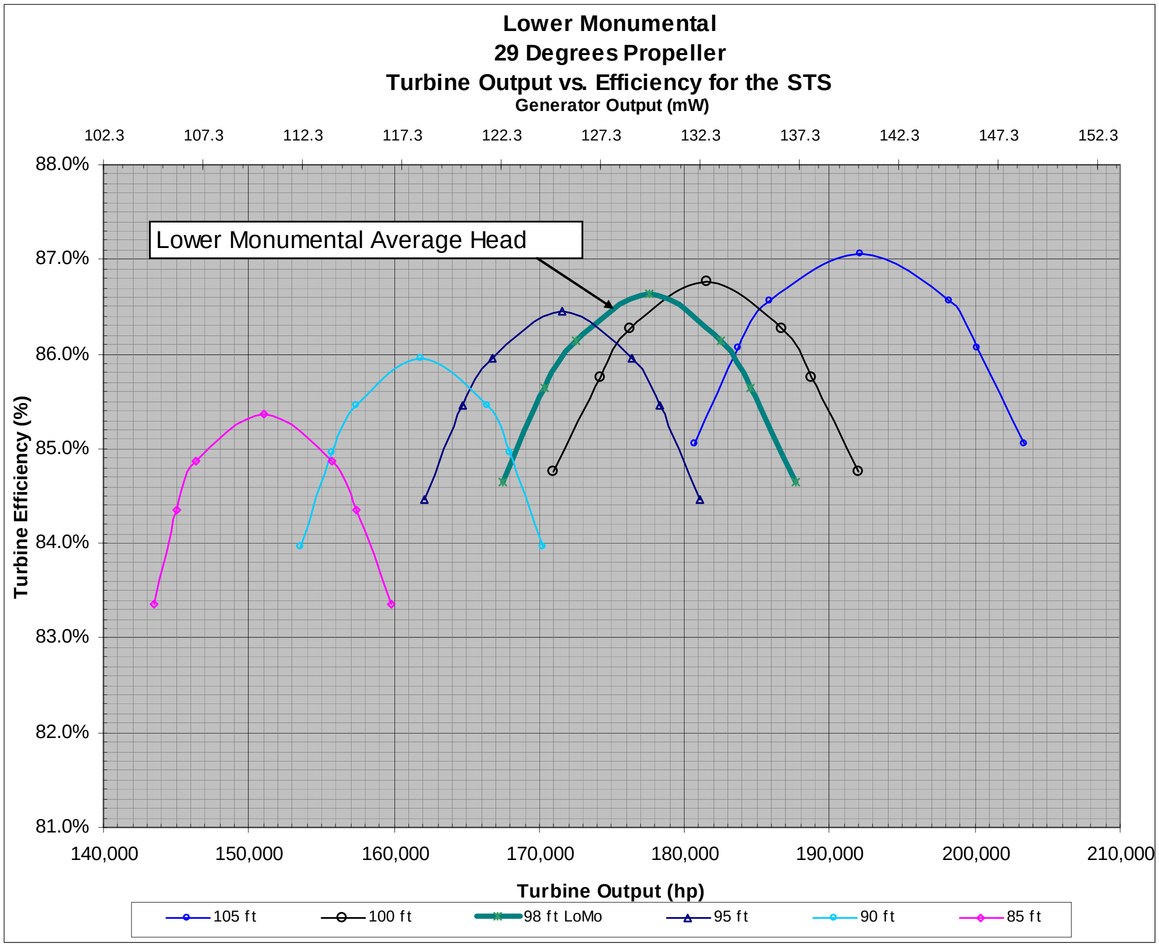


Figure C-21 (continued). Lower Monumental Units 1-3 with Submersible Traveling Screens (STS)

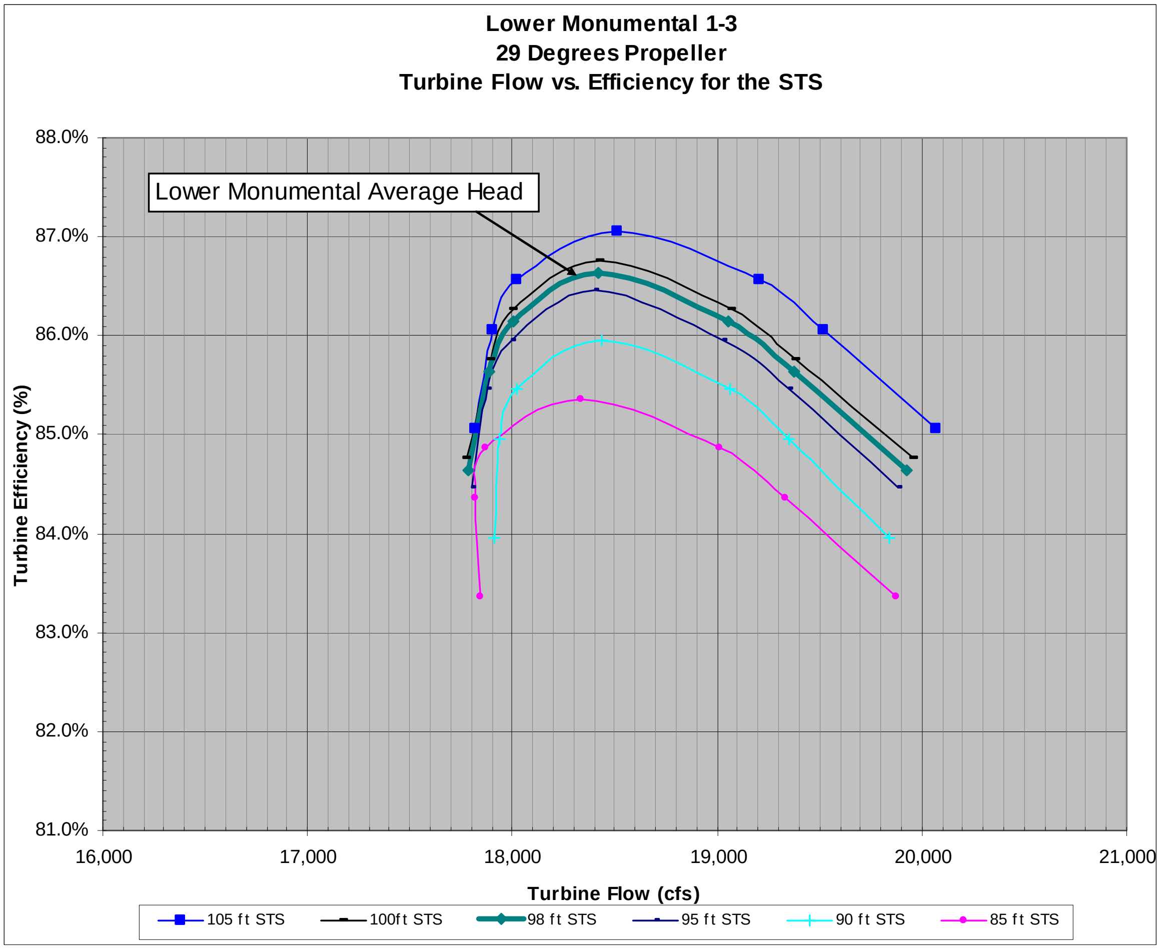


Figure C-22. John Day Units 1-16 with STS

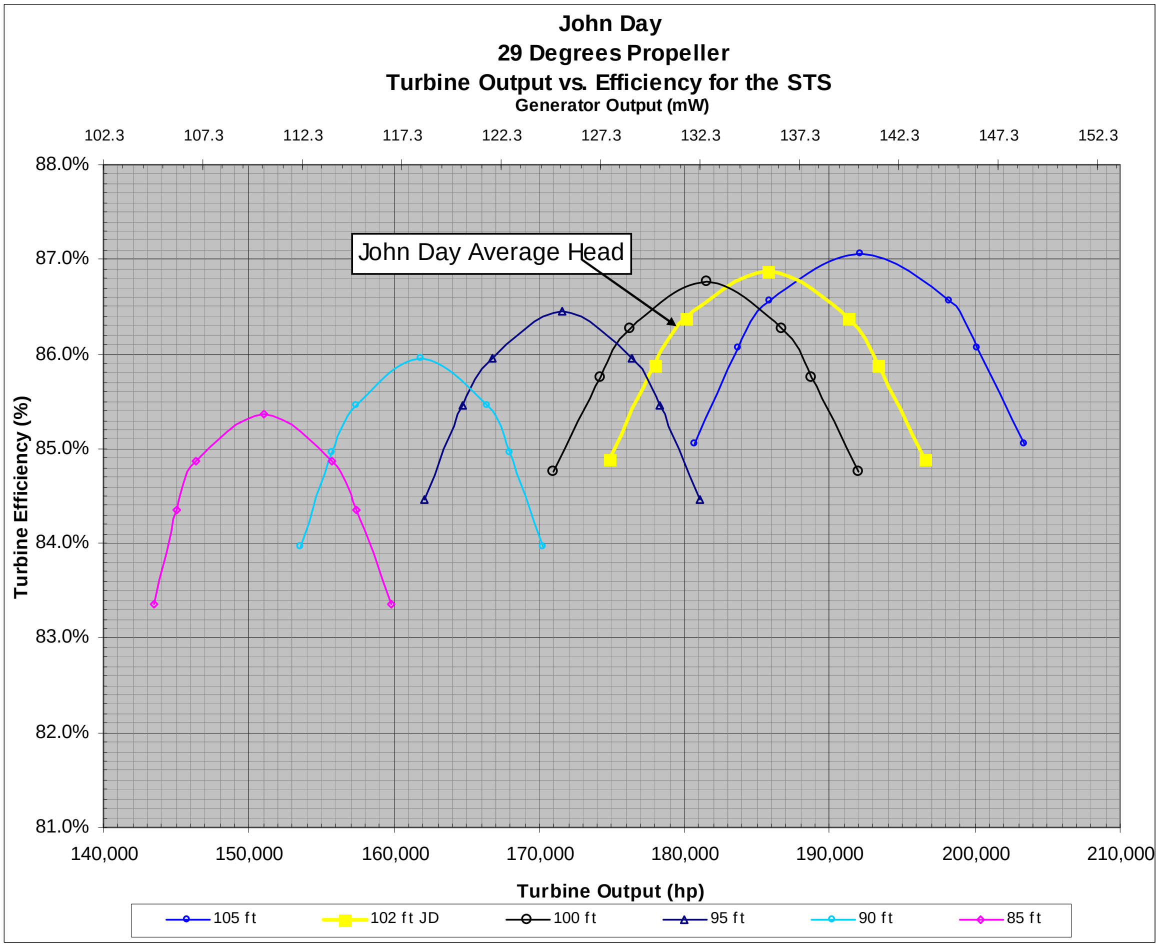
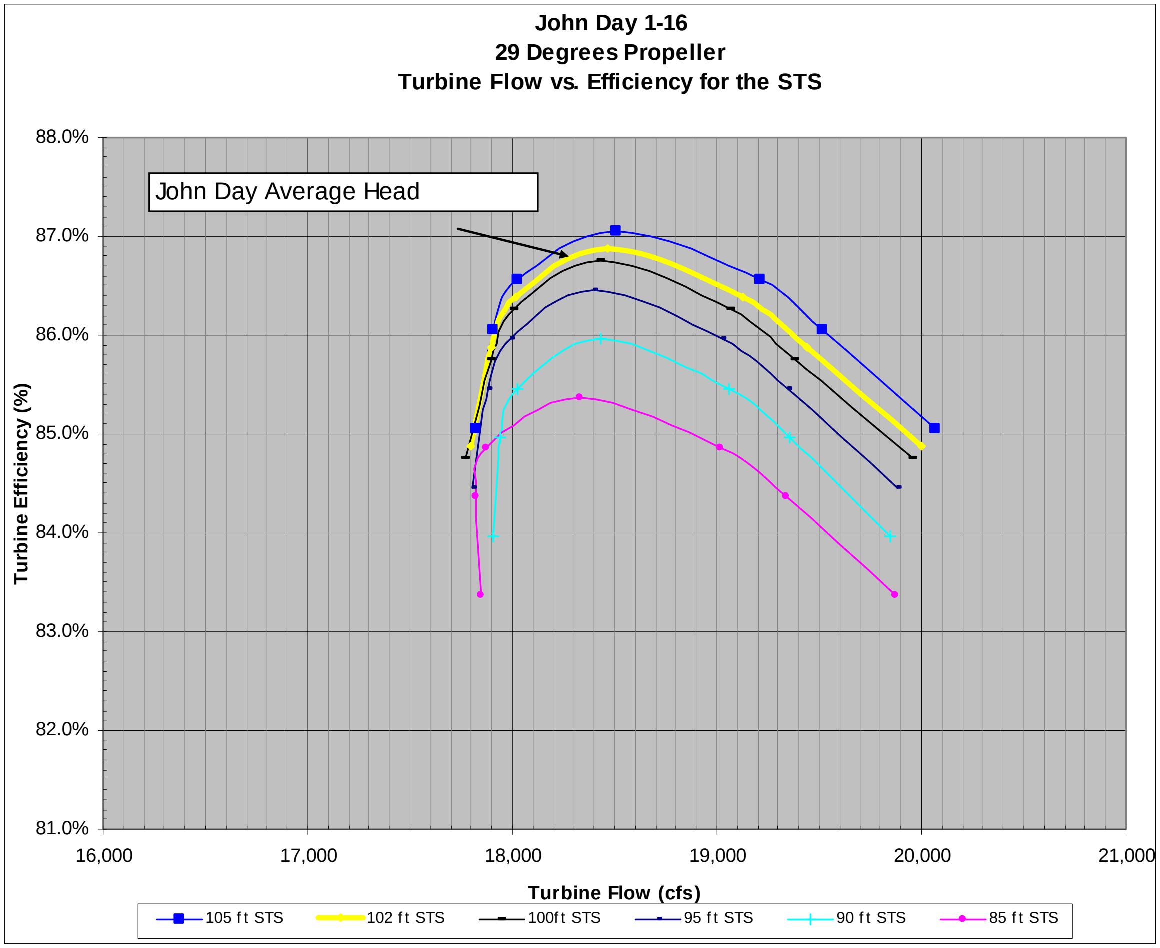


Figure C-22 (continued). John Day Units 1-16 with STS



C.6.0. Summary

1. A runner blade angle of 29 degrees for the 25 BLH units being studied for the Kaplan repair strategy appears biologically satisfactory as a temporary or permanent solution.
2. Should a mechanism failure occur on any of the studied BLH units, the selection of the blade angle to which a permanent repair to propeller is made should be reviewed considering any pertinent information on system operation for fish passage or available turbine fish passage enhancements.
3. An index test on any unit made a temporary propeller or permanent propeller should be performed and FPP and 1% operating criteria revised and adhered to.
4. A biological field test incorporating Hi-Z balloon tags and sensor fish for direct mortality and injury and total turbine survival tags for indirect survival should be performed to confirm safe fish passage conditions. This testing may be done on an existing operating Kaplan by fixing the blades in position and performing the necessary testing.

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D.1.0. Introduction

D.1.1. Purpose and Scope

The purpose of this appendix is to estimate the generation output and corresponding hydropower benefits for several repair strategies under consideration to address future failures of the blade adjustment mechanisms in the 25 identical turbines installed in the John Day, Lower Monumental, Little Goose, and Lower Granite powerhouses. The results in this appendix serve as input to Appendix E, *Economics*, which evaluates the benefits and costs of the various repair strategies.

D.1.2. Project Descriptions

John Day is a Portland District storage project located on the Columbia River (river mile 215.6) in the states of Oregon and Washington. Project operating purposes include flood control, hydropower, navigation, fish/wildlife, recreation, irrigation, and water quality. The project with units 1-16 was completed in 1971. Each powerhouse unit has a 115% overload rating of 155.25 MW (163.42 MVA @ 0.95 PF).

Lower Monumental, Little Goose, and Lower Granite are Walla Walla District run-of-river projects located on the Snake River (river miles 41.6, 70.3 and 107.5, respectively) in the state of Washington. Operating purposes for all three projects include hydropower, navigation, fish/wildlife, recreation, irrigation, and water quality. The initial Lower Monumental and Little Goose projects with units 1-3 were completed in 1970, while the initial Lower Granite project with units 1-3 was completed in 1975. The addition of units 4-6 at all three projects was completed in 1978. Each powerhouse unit at all three projects has a 115% overload rating of 155.25 MW (163.42 MVA @ 0.95 PF).

The 25 identical Kaplan turbines installed in John Day units 1-16 and in units 1-3 at the three Snake River projects were designed and manufactured by Baldwin-Lima-Hamilton (BLH), while the nine identical Kaplan turbines installed in units 4-6 at the three Snake River projects were designed and manufactured by Allis Chalmers (AC). Recent similar failures have occurred in the blade adjustment mechanisms of the 25 BLH turbines. Several repair strategies are being considered for addressing future such failures, which are described below.

D.1.3. Study Participants

This appendix was prepared by the Hydropower Analysis Center (HAC). Mike Egge performed the energy and economic analyses and drafted the appendix text, tables, and figures. Non-HAC participants included: (1) George Medina, Portland District, who served as Project Manager; (2) Sonja Dodge, Northwestern Division Water Management, who performed the Hydro System Seasonal Regulation (HYSSR) simulation study and provided model flow and forebay elevation input for the Turbine Energy Analysis Model (TEAM); (3) Dan Watson, Hydroelectric Design Center (HDC), who provided unit performance data, schedules, and cost estimates; and (4) John Johannis, Bonneville Power Administration (BPA), who provided the power values used in estimating hydropower benefits.

D.1.4. Repair Strategies Evaluated

This study evaluated three repair strategies for addressing future failures of the blade adjustment mechanism in the BLH Kaplan turbines at John Day, Lower Monumental, Little Goose, and Lower Granite. Under each strategy, the John Day evaluation analyzed two different Kaplan failure scenarios (five failures and eight failures over the economic period of analysis, where successive failures were assumed to occur 24 months apart), while each Snake River project evaluation analyzed one Kaplan failure scenario (one failure over the economic period of analysis). For each repair strategy, the initial Kaplan failure was assumed to occur in FY 2010, the first year in the economic period of analysis (assumed to be 20 years in length).

The Kaplan repair strategies, along with the study base case, are briefly described below.

1. **Base Case.** The base case assumes there are no Kaplan turbine failures over the economic period of analysis. The base case is used to economically compare the merits of the three repair strategies. For each strategy, project generation benefits and repair costs are compared to the project generation benefits of the base case.

2. **Strategy A: Failed Turbine to Remain Kaplan Type.** Under this strategy, a failed turbine is repaired to operate temporarily as a propeller type until permanent repairs can be commenced to return the turbine to full Kaplan operation. The analysis for Strategy A assumes that three months is required to repair the failed turbine to propeller operation, that propeller operation continues for 18 months, and that an additional 18 months is required to return the turbine to full Kaplan operation.

3. **Strategy B: Failed Turbine to Become Propeller Type.** Under this strategy, a failed turbine is repaired to operate as a propeller type on an indefinite basis. The analysis for Strategy B assumes that five months is required to repair the failed turbine to propeller operation and that propeller operation continues throughout the remainder of the 20-year period of analysis.

4. **Strategy C: Failed Turbine to Remain Kaplan Type with IDIQ.** This strategy is similar to Strategy A in that it returns a failed turbine to full Kaplan operation. However, the failed turbine is not repaired to operate temporarily as a propeller type as in Strategy A. Instead, Strategy C uses an Indefinite Delivery Indefinite Quantity (IDIQ) contract, which reduces the amount of time (to 24 months) required to return the failed turbine to full Kaplan operation compared to Strategy A.

Figures G-5 through G-9 in Appendix G, *Construction Schedules,* provide graphical depictions of the various Kaplan repair strategies for John Day and each of the three Snake River projects.

D.1.5. Procedure

The development of project generation benefits for this study included the following steps:

- Run the HYSSR model to obtain a sequential stream flow regulation for John Day, Lower Monumental, Little Goose, and Lower Granite projects for the period from August 1928 through July 1978. For each project, determine weekly average releases and reservoir elevations for this 50-year hydrologic period of record.

- For each project, input project operational data (including HYSSR flows and reservoir elevations, turbine-generator performance, unit loading orders, unit maintenance schedules, spill for fish requirements, and powerhouse minimum flow requirements) into TEAM, used to estimate project energy generation output for each year and week in the 50-year hydrologic period of record.
- For each project, run TEAM for each scenario (combination of operating Kaplan turbines, operating propeller turbines and units out of service) required to simulate the base case and each Kaplan repair strategy over the 20-year economic period of analysis.
- Determine average weekly power values from BPA supplied data for super-peak (SP) hours, heavy-load hours (HLH) and light-load hours (LLH) for each week in the 50-year hydrologic period of record.
- For each project, use the COMPARE spreadsheet to determine the value of generation for each scenario required to simulate the base case and each Kaplan repair strategy over the 20-year economic period of analysis.
- For each project, input yearly value of generation and repair cost data into the economics spreadsheet, then determine for each Kaplan repair strategy the present value (to FY 2010) of the net benefits compared to the base case.
- Conduct sensitivity analyses on each Kaplan repair strategy.

The first five steps listed above are described in this appendix, while the remaining two steps are described in Appendix E, *Economics*.

Some parts of the study analysis were performed using spreadsheet software. Arithmetic operations and totals were taken to full decimal accuracy within the spreadsheet. Tables found in this report have been rounded to a specified level of accuracy after the mathematical computations have been performed; therefore, rounded totals may not equal the summation of rounded values.

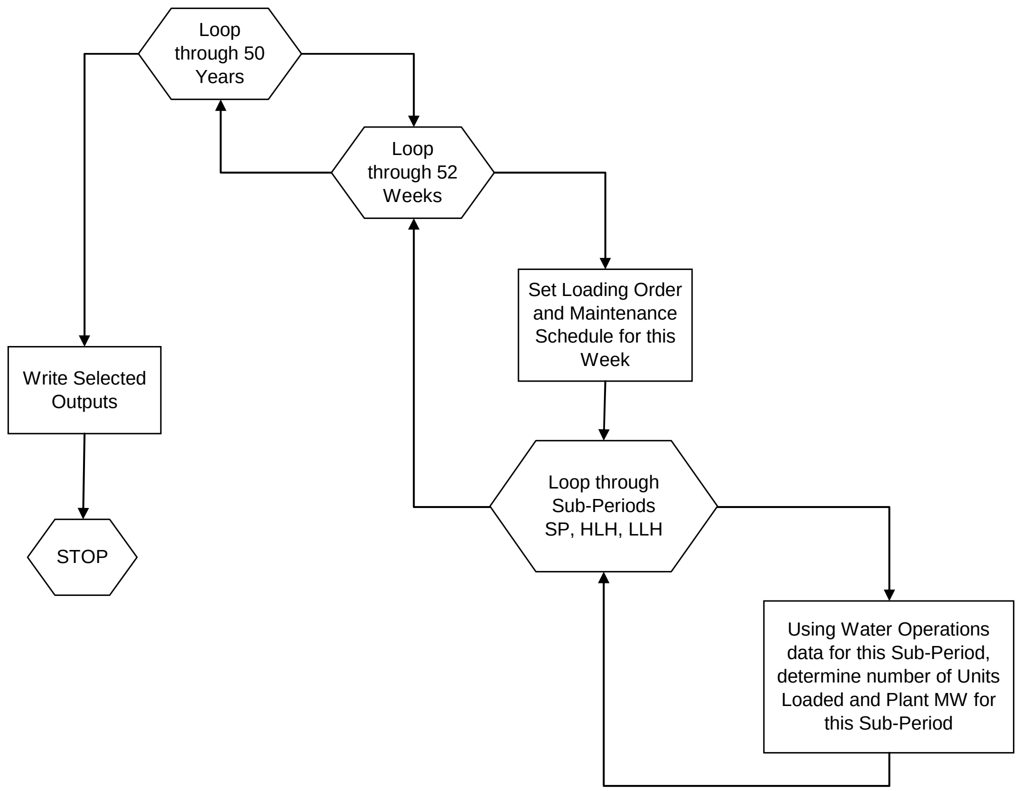
D.2.0. Energy Production

D.2.1. General

For the base case and each Kaplan repair strategy, TEAM was used to estimate the energy generation output of John Day, Lower Monumental, Little Goose, and Lower Granite (abbreviated JDA, LMN, LGS and LWG, respectively). Since TEAM was designed to run on a single project basis, a separate setup of the model was developed for each of the four projects. A simplified logic diagram for TEAM is shown in Figure D-1.

Briefly, TEAM is used to allocate project discharge to units at a power plant with multiple and/or different-sized generating units. When the discharge allocation has been determined for each generating unit, the power output for each unit is computed based on the head and unit efficiency specified. Using available discharges adjusted for various project flow losses, TEAM simulates the loading of generating units in a given sequence, up to the point that all discharge is utilized for generation and any excess is spilled. The unit loading order is specified for each month of the year, thereby allowing the model to reflect variations in loading order and unit availability.

Figure D-1. TEAM Logic Flow



D.2.2. TEAM Overview

The TEAM was set up to use a weekly time step for up to a 62-year hydrologic period of record. In addition, each week is further broken into three sub-periods: (1) the 30-hour SP, the six highest value hours during the 6 AM to 10 PM period on Monday through Friday; (2) the 66-hour HLH, the 6 AM to 10 PM period on Monday through Saturday (not including the SP hours); and (3) the 72-hour LLH, the remaining hours of the week. This allows the energy generation output from TEAM to be valued at the appropriate price levels.

When executed, TEAM loops through all years in the long-term hydrology (50 years used in this study); within each year TEAM then loops through each week, and within each week TEAM loops through the three sub-periods starting with SP, then HLH, and finally LLH. For each sub-period, TEAM uses the defined flow and head for that sub-period and loops through the units based on the loading order specified for that week while checking the maintenance schedule for unit availability. It loads as many units as needed to fully use the sub-period flow. Using performance curves specified for each unit, units are first loaded at their best efficiency point and if after all units are loaded there is flow remaining, units are then loaded up to their generator limit. For the first two sub-periods (SP and HLH), if flow remains after all units have been loaded up to their maximum limit, the remaining flow is moved to the next sub-period (from SP to HLH and from HLH to LLH). For the last sub-period (LLH), if flow remains, all sub-periods are set to the weekly average flow and any unused flow (spill) is assumed to occur in all sub-periods. After all the years are completed, depending on the selected output, power generation, total flow, power flow, unused power flow, gross head, tailwater, and overall efficiency are output for each sub-period to the TEAM spreadsheet. In addition, if selected, unit-specific output is available for each sub-period. A brief description of TEAM inputs and outputs is provided below.

D.2.3. TEAM Inputs

D.2.3.1. Turbine Performance Data

The TEAM requires detailed information for combined turbine-generator performance for each type of unit included in the evaluation. For each unit, TEAM requires four polynomial equations (up to 3rd order) that are each a function of gross head. These are Power (MW) at Best Gate (PBG), Power (MW) at Full Gate (PFG), Efficiency (%) at Best Gate (EBG), and Efficiency (%) at Full Gate (EFG). For each unit the generator upper limit in MW is required. In addition, four values (starting head, starting MW, ending head, and ending MW) are included to define an upper cavitation limit. This data is included in the TEAM spreadsheet on worksheet "Unit Performance." This sheet also includes the total number of units for the power plant (16 for JDA and six for LMN, LGS and LWG) and the number of different types of units. The unit type for each unit is assigned on worksheet "Unit Operations."

The Kaplan Turbine Repair Study required nine different sets of unit performance equations (i.e., nine unit types) as input to TEAM in order to model the operation of the four projects under the various study scenarios used to simulate the base case and each Kaplan repair strategy. This is because simulating the various study scenarios for four projects required three turbine types (BLH Kaplan, AC Kaplan and propeller) and two fish screen scenarios (fish screens in place during April through mid-December and fish screens removed during mid-December through March), where two different fish screen types needed to be modeled (STS screens for JDA and LMN, ESBS screens for LGS and LWG). A summary of the unit performance equations, along with their corresponding graphs, is provided in Appendix A, *Turbine Engineering*.

D.2.3.2. Loading Order

For TEAM to load units for each sub-period, it needs to know the desired loading order. TEAM allows the input of up to 14 different loading orders, which are entered into TEAM on worksheet "Unit Operations." The loading order assigned to each week of the year is also entered on worksheet "Unit Operations."

The initial loading orders (with Kaplan turbines on all project units) entered into TEAM for JDA consisted of two loading orders. The first loading order represented a typical loading order during the period mid-July through March, while the second loading order represented a typical loading order during the period April through mid-July, when top spillway weir operation takes place. For LMN, LGS and LWG, a single year-round initial loading order was entered into TEAM.

Generally, the initial loading orders entered into TEAM for the four study projects are consistent with the unit operation priorities summarized in the March 2008 Fish Passage Plan (FPP). The FPP unit operation priority for each project is shown in Appendix B, *Biological and Environmental Considerations*. Due to the modeling limitations of TEAM, it was not possible to specify LMN and LWG initial loading orders that would be entirely consistent with FPP unit operation priorities. During the period March through November, the FPP unit operation priority for LMN is a function of project flow. And during the period April through October, the FPP unit operations priority for LWG is a function of time of day (daytime operation versus nighttime operation). In the case of nighttime operation, the FPP unit operations priority for LWG is also a function of whether there is enough project flow to run priority units. Since loading orders in TEAM are specified on a weekly basis, it is not possible to enter loading orders into TEAM that are a function of project flow. Due to the particular FPP unit operation priorities specified for JDA and LWG, time of day based loading orders entirely consistent with the FPP could be specified for JDA but not for LWG.

Due to a turbine failure, the LMN unit 1 turbine currently operates as a propeller. The FPP unit operation priority for LMN is based on the current status of unit 1. Consistent with the base case assumption of the Kaplan Turbine Repair Study, the study assumes unit 1 will be returned to full Kaplan operation prior to FY 2010, the first year in the economic period of analysis. Thus, the initial loading order entered into TEAM for LMN is based on full Kaplan operation for unit 1.

Under Kaplan repair strategies A and B, a failed Kaplan turbine is converted temporarily or indefinitely to propeller operation. The study team concluded that the most likely loading order scenario for a unit with a propeller turbine would be to place the unit last in the loading order. Thus, any TEAM run simulating one or more units with propeller operation moved those units to the end of the loading order. Any unit that was later returned to full Kaplan operation was moved to the position it occupied prior to the turbine failure.

D.2.3.3. Unit Maintenance

The TEAM allows up to a 5-year maintenance/unit outage cycle to be entered on a week-by-week basis specifying which units are unavailable for that week (from one to the entire plant if desired). For studies whose hydrologic period of record exceeds the number of years in the cycle (a 50-year hydrologic period of record was used in this study), TEAM repeats the cycle. In this study, a 5-year cycle was included for all four projects, so for the first 5 years the cycle was used exactly as entered. In year 6 of the study, TEAM began the cycle again using year 1 in the cycle to represent year 6 in the study and so on. This data is entered into TEAM on worksheet “Unit Operations.”

Based on information provided by Portland and Walla Walla District operations personnel, unit overhauls and unit annual maintenance were scheduled in TEAM over the 16-week period from mid-August through November (TEAM weeks 3-18) for all four projects. The operations personnel also provided estimates for the frequency and weekly duration of unit overhauls and the weekly duration of unit annual maintenance, estimates that were incorporated into the unit maintenance schedules developed for input into TEAM. These estimates are summarized below.

Three unit overhauls are typically performed at JDA each year, where each outage is six weeks in duration and there is a 2-week overlap between overhauls. In a given year, any JDA unit not undergoing an overhaul will undergo a 1-week annual maintenance outage. In order to maintain the same number of unit overhauls and unit annual maintenance outages in each of the five maintenance cycles, unit overhauls and unit annual maintenance outages for JDA unit 16 were not modeled in TEAM.

Each of the six units at LMN, LGS and LWG undergoes a 4-month (or 16-week) overhaul every 6 years. In a given year, any unit not undergoing an overhaul will undergo a 1-week annual maintenance outage. In order to maintain the same number of unit overhauls and unit annual maintenance outages in each of the five maintenance cycles, unit overhauls and unit annual maintenance outages for unit 3 at LMN, LGS and LWG were not modeled in TEAM. Unit 3 at each of the three projects is the unit assumed to experience a turbine failure under each of the three Kaplan repair strategies.

D.2.3.4. Unit Operation to Within One Percent of Peak Efficiency

The March 2008 FPP stipulates that the turbine-generator units at JDA, LMN, LGS and LWG operate to within 1% of their peak efficiency point in order to enhance fish survival. This requirement is mandatory during the months April through October, but the requirement is relaxed during the months November through March in the cases of power emergencies.

Unit operation to within 1% of peak efficiency can be specified in TEAM on a week-by-week basis. This input is entered on worksheet "Unit Operations." Entering a "Y" in a given week instructs TEAM to enforce the 1% requirement during that week, while entering an "N" in a given week instructs TEAM to relax the 1% requirement during that week.

For this study, TEAM was instructed to enforce the 1% requirement during the months April through October (TEAM weeks 1-13 and 36-52) and to relax the 1% requirement during the months November through March (TEAM weeks 14-35).

D.2.3.5. Unit Performance Loss Due to Fish Screens

The TEAM allows for the use of a single equation of the form:

ULOSS = L1 * H^L2 * Q^L3,

This equation can be used to estimate the loss in unit performance (power) due to the installation of fish screens. In the equation, H = unit head, Q = unit discharge, ULOSS = percent loss in unit performance, and L1, L2 and L3 are constants that define the impact of a given fish screen type on the units of a given project. The fish screen losses option is selected by entering values for L1, L2 and L3 on worksheet "Unit Operations." Also entered on worksheet "Unit Operations" are the weeks of the year for which the fish screen loss equation is to be applied.

If the fish screen losses option is selected, TEAM first determines the final unit loading head (H), discharge (Q) and power (P) for each unit loaded during a given week and sub-period. Then, for each loaded unit, TEAM uses the H and Q values to calculate the value for ULOSS and applies the ULOSS value to the final unit loading power to estimate the unit power reduction (ULOSS * P) with fish screen losses taken into account.

The TEAM accounted for fish screen losses during the time of the year (April through mid-December) when fish screen operation takes place at each of the four study projects. In reality, fish screen losses in a project unit are dependent on the fish screen and unit performance characteristics of the unit. Since TEAM applies the same ULOSS equation coefficients to all project units regardless of the fish screen and unit performance characteristics of each unit, TEAM was not able to use the fish screen losses option described above to take into account unit power losses when fish screens are installed.

Instead, for each scenario (combination of operating Kaplan turbines, operating propeller turbines and units out of service) required to simulate the base case and each Kaplan repair strategy over the 20-year economic period of analysis, TEAM was run twice. The first run of each pair assigned to each unit the equations representing unit performance without fish screens, while the second run of each pair assigned to each unit the equations representing unit performance with fish screens. The TEAM output for mid-December through March (TEAM weeks 21-35) from the first run (without fish screens) and the TEAM output for April through mid-December (TEAM weeks 1-20 and 36-52) from the second run (with fish screens) were then merged. This produced TEAM output representing project operation with fish screens removed during mid-December through March and project operation with fish screens installed during April through mid-December.

D.2.3.6. Water Operations/Hydrology

The TEAM requires water operation data for each week for every year evaluated. The HYSSR model was used to simulate the operation of the Columbia River Basin system of projects over the 50-year hydrologic period of record from August 1928 through July 1978. The HYSSR output that served as input to TEAM for this study included regulated flows and forebay elevations for the 50-year period for each of the four study projects. Since HYSSR uses a 14-period per year routing interval (monthly with April and August each split into two periods), TEAM converted the HYSSR monthly flows and forebay elevations into weekly equivalents. For a TEAM week that fell entirely within one month, TEAM used the HYSSR monthly value to represent the weekly value. For a TEAM week that crossed two months, TEAM used a weighted average of the two HYSSR monthly values to represent the weekly value, based on the number of days of the week that fell in each of the two months.

Also required as input into TEAM is data for determining the project tailwater elevation for each week for every year evaluated. This input can either be in the form of a tailwater rating table or a constant tailwater elevation to be applied to each week of each year. For this study, the tailwater rating tables for the four projects that serve as input to the HYSSR model were used as input to TEAM. Other data that served as input to TEAM for each of the four projects included:

- Project non-power discharges and flow losses such as lockages, flows through fish ladders, juvenile bypass systems, ice and trash sluiceways, and auxiliary water supply for fishways (not included is spill for fish requirements, which are entered into TEAM separately).
- Percent of project flow spilled for fish.
- Upper limit on project flow spilled for fish.
- Minimum powerhouse discharge.

Project values for each of the above four data types were entered into TEAM for each of the 14 HYSSR periods. The same set of project values was used for all years evaluated by TEAM. These values are based on information contained in the March 2008 FPP.

The TEAM input described in this section is entered on worksheet “Water Monthly.”

D.2.3.7. Sub-Periods

Section D.2.2 notes that each TEAM week is broken into three sub-periods: the 30-hour SP, the 66-hour HLH, and the 72-hour LLH. This section describes the weekly process by which project units are loaded in each of the three sub-periods.

In order to load units in each sub-period, TEAM needs to distribute the weekly flow between the three sub-periods. This is accomplished by multiplying a weekly “shaping factor” for each sub-period by the weekly flow. The shaping factors used by TEAM are stored in worksheet “Sub Period Weekly Factors.” This worksheet contains a table of shaping factors for each of the three sub-periods. Each table contains a shaping factor for each week in the 50-year hydrologic period analyzed by TEAM. The weekly shaping factors are calculated by TEAM based on monthly shaping factors that are entered into worksheet “Sub-Period Monthly Factors.” The monthly shaping factors were developed by the BPA.

D.2.3.8. Other Inputs

The TEAM run execution is controlled on worksheet "Control." The number of years included in the input data is set here, along with the number of periods (weeks in this case) in the year. The user can select the first and last year to run (anywhere from one to the total years available can be selected). The user can choose whether to run sub-periods or only use period average data. Run identifiers are also entered on this worksheet. The user can select the desired outputs here. The user can also choose to have run-status messages written to this worksheet during TEAM execution. A prefix is entered for naming output worksheets. If the user decides to save the file, a unique file name based on run date and time and the run identifier is created. After the file is saved, the file name and the time it was saved are written to this worksheet.

D.2.4. TEAM Outputs

Four types of output can be selected. Each type (except debug) is written to its own worksheet. Desired output and corresponding worksheet names are set in worksheet "Control."

- Detailed Unit Output: Provides period-by-period detailed unit loading information. Only for monthly data of 10 years or less.
- Quick Unit Output: Added to the Visual Basic version as an alternative to the existing detailed unit output. This provides abbreviated period-by-period output, which is much quicker than the detailed unit output.
- Table Output: User-friendly tabular output used for investment evaluations. Available for individual sub-periods and runs based on period average flows without sub-periods. A sub-period summary table is also produced.
- Debug: These were the embedded write statements used for debugging included in the original HALLO model (was used as the starting point for the development of TEAM). Writes to a text file.

D.2.5. TEAM Scenarios

A number of TEAM scenarios (combination of operating Kaplan turbines, operating propeller turbines and units out of service) were required to simulate the base case and each Kaplan repair strategy over the 20-year economic period of analysis. A total of 36 TEAM runs (18 runs without fish screens and 18 runs with fish screens) were required for JDA, while a total of six TEAM runs (three runs without fish screens and three runs with fish screens) were required for each of the three Snake River projects.

Table D-1 summarizes for JDA, LMN, LGS and LWG the TEAM scenarios corresponding to each pair of TEAM runs. Also shown in Table D-1 for each project is the average annual generation in gigawatt hours (GWh) for each TEAM scenario, along with the reduction in annual generation (in GWh) from the base case (Kaplan turbines on all units and no units out of service).

Table D-1 shows that for each Snake River project, there is a negative reduction in annual generation under TEAM Run R03. In other words, if a failed turbine is repaired to propeller operation for the entire year, there is a gain in project generation compared to the base case. This result can be explained as follows:

Table D-1. TEAM Scenarios and Average Annual Generation

Run Pair Designation	Number of Operating Kaplans (K)	Number of Operating Propellers (P)	Number of Units Out of Service (U)	Average Annual Generation (GWh)	Reduction in Annual Generation From Base Case (GWh)
TEAM Results for John Day Project					
R01	16	0	0	9,636	----
R02	15	0	1	9,612	24
R03	14	0	2	9,576	60
R04	15	1	0	9,635	1
R05	14	1	1	9,611	25
R06	14	2	0	9,635	1
R07	13	2	1	9,610	26
R08	13	3	0	9,634	2
R09	12	3	1	9,609	27
R10	12	4	0	9,632	3
R11	11	4	1	9,607	29
R12	11	5	0	9,631	5
R13	10	5	1	9,605	31
R14	10	6	0	9,629	7
R15	9	6	1	9,602	34
R16	9	7	0	9,626	10
R17	8	7	1	9,598	38
R18	8	8	0	9,622	14
TEAM Results for Lower Monumental Project					
R01	6	0	0	2,517	----
R02	5	0	1	2,458	60
R03	5	1	0	2,521	-4
TEAM Results for Little Goose Project					
R01	6	0	0	2,443	----
R02	5	0	1	2,398	45
R03	5	1	0	2,452	-9
TEAM Results for Lower Granite Project					
R01	6	0	0	2,465	----
R02	5	0	1	2,401	64
R03	5	1	0	2,472	-8

- There are two families of Kaplan turbines at each of the three Snake River projects, units 1-3 (BLH turbines) and units 4-6 (AC turbines). The newer AC turbines are more efficient than the older BLH turbines.
- The initial unit loading order used in TEAM for each Snake River project, which is as consistent with the unit operating priorities specified in the March 2008 FFP as the model will allow, generally favor the loading of units 1-3 ahead of units 4-6.

- The study analysis assumes that the turbine failure at each Snake River project takes place on unit 3. If the turbine on unit 3 is repaired to propeller operation upon failure, unit 3 is placed last in the unit loading order for as long as the turbine operates as a propeller.
- During this time, the more efficient units 4-6 move up in the unit loading order.
- Depending upon the amount of project flow available during a given period, the generation produced with five Kaplan turbines and one propeller turbine can exceed the generation produced with six Kaplan turbines due to the increase in project efficiency.
- Since TEAM Run R03 for each Snake River project simulates yearlong propeller operation for unit 3, unit 3 is placed last in the unit loading order over the entire year. During this time, there are at least some periods where the generation produced at each project exceeds the generation that can be produced with six Kaplan turbines. Thus, there is a gain in annual generation for each Snake River project under TEAM Run R03 compared to the base case.

D.3.0. Valuation of Energy Output

D.3.1. Overview

The BPA has developed and provided to the Corps of Engineers the projected hourly market-clearing prices based on the 50 years of hydrologic data used in estimating energy production. These projections were developed using an electric energy market model called AURORA. AURORA is owned and licensed by EPIS Incorporated.

D.3.2. AURORA Production Cost Model

The hourly market-clearing price is based upon a fixed set of resources dispatched in least-cost order to meet demand. The hourly price is set equal to the variable cost of the marginal resource needed to meet the last unit of demand. A long-term resource optimization feature within the AURORA model allows generating resources to be added or retired based on economic profitability. Market-clearing price and the resource portfolio are interdependent. Market-clearing price affects the revenues any particular resource can earn and consequently will affect which resources are added or retired. Iterative solutions of resource portfolios and market-clearing prices are completed in AURORA until the difference between the last two iterations is minimal. AURORA sets the market-clearing price using assumptions of demand levels (load) and supply costs. The demand forecast implicitly includes the effect of price elasticity over time. The supply side is defined by the cost and operating characteristics of individual electric generating plants, including resource capacity, heat rate, and fuel price. AURORA incorporates the effect that transmission capacity and prices have on the system's ability to move generation output between areas. AURORA recognizes 13 areas within the Western Electricity Coordinating Council (WECC), largely defined by major transmission interconnections. For example, California is split into two market areas, north and south; Oregon, Washington, and Northern Idaho are combined while Southern Idaho is a separate market area; and British Columbia and Alberta (Canada) are combined into a single market area.

The assumptions in AURORA for determining power values include:

- Load year October 2009 - September 2010 was modeled using AURORA.
- 50 water years (August 1928 through July 1978) of regional monthly generation obtained from BPA's HYDROSIM model served as input to AURORA.

- For each of the 50 water years, monthly generation was simulated for the modeled load year.
- An hourly marginal cost for each hour of the period October 2009 - September 2010 was determined for each water year's generation.
- BPA provided 8,760 hourly marginal costs values for each of the 50 water years (leap years not considered).
- These values represent the Mid-Columbia trading prices.

To describe AURORA's methodology, it is helpful to distinguish between two main aspects of modeling the electric energy market: the short-term determination of the hourly market-clearing price and the long-term optimization of the resource portfolio.

D.3.2.1. Hourly Price Determination

As noted earlier, the hourly market-clearing price is based upon a fixed set of resources dispatched in least-cost order to meet demand. The hourly price is set equal to the variable cost of the marginal resource. AURORA places two restrictions on the hourly operation of generating plants. First, AURORA simulates the "must run" status of certain units. Second, AURORA recognizes that costs associated with ramping generation levels up and down will make the economic dispatch of plants on an hourly basis impractical. To account for this, AURORA commits generating plants to operate at weekly intervals. AURORA uses a weekly price forecast to determine plant profitability and to model the commitment decision.

D.3.2.2. Long-Term Resource Optimization

The long-term resource optimization feature within AURORA allows generating resources to be added or retired based on economic profitability. Economic profitability is measured as the net present value (NPV) of revenue minus the NPV of costs. A potential new resource that is economically profitable will be added to the resource database. An existing resource that is not economically profitable will be retired from the resource database. In reality, the market-clearing price (hence the profitability of a resource) and the resource portfolio are interdependent. The market-clearing price will affect the revenues any particular resource can earn, and consequently, it will affect which resources are added and retired. In the same way, changes in the resource portfolio will change the supply cost structure, which will affect the market-clearing price. AURORA uses an iterative process to address this interdependency.

AURORA's iterative process uses a preliminary price forecast to evaluate existing and potential new resources in terms of their economic profitability. If an existing resource is not profitable, it becomes a candidate for retirement. Alternatively, if a potential new resource is economically profitable, it is a candidate to be added to the resource portfolio. In the first step of the iterative process, a small set of new resources is drawn from those with the greatest profitability and added to the resource base. Similarly, a small set of the most unprofitable existing resources is retired. This modified resource portfolio is used in the next step in the iterative process to derive a revised market-clearing price forecast. The modified price will then drive a new iteration of resource changes. AURORA will continue the iterative solution of the resources portfolio and the market-clearing price until the difference in price between the last two iterations reaches a minimum and the iterations converge on a stable solution.

D.3.3. Energy Values Used in Evaluation

The hourly AURORA energy values cannot be directly used in the evaluation since TEAM is calculating average weekly generation. To derive average weekly prices, the hourly AURORA prices were grouped into three weekly sub-periods: SP, HLH, and LLH for each of the weeks in the 50-year period of record. The following assumptions were used:

- SP will be defined as the highest price 6 hours per day during the traditional HLH period (6 AM to 10 PM or 0600 to 2200) on Monday through Friday for a total of 30 hours per week.
- HLH are usually the 16 hours per day for the period 6 AM to 10 PM (0600 to 2200) for Monday through Saturday for a total of 96 hours per week. Since this includes SP hours, which are a subset of HLH, the HLH were limited to 66 hours per week. This is based on 96 hours minus the 30 SP hours (highest 6 hours per day on Monday through Friday).
- LLH are 8 hours per day on Monday through Saturday and all day Sunday for a total of 72 hours per week. Although certain holidays are considered LLH for the entire day, they are not included in the breakdown used here.
- Holidays and Daylight Savings are not accounted for.
- Days used to break down sub-periods are based on the August 2009 through July 2010 period for all water years.
- Each week has 7 days except for week 52, which has 8 days. Based on the assumed year for prices, this extra day is a Saturday, so the last week has 192 hours, but only 30 SP hours.

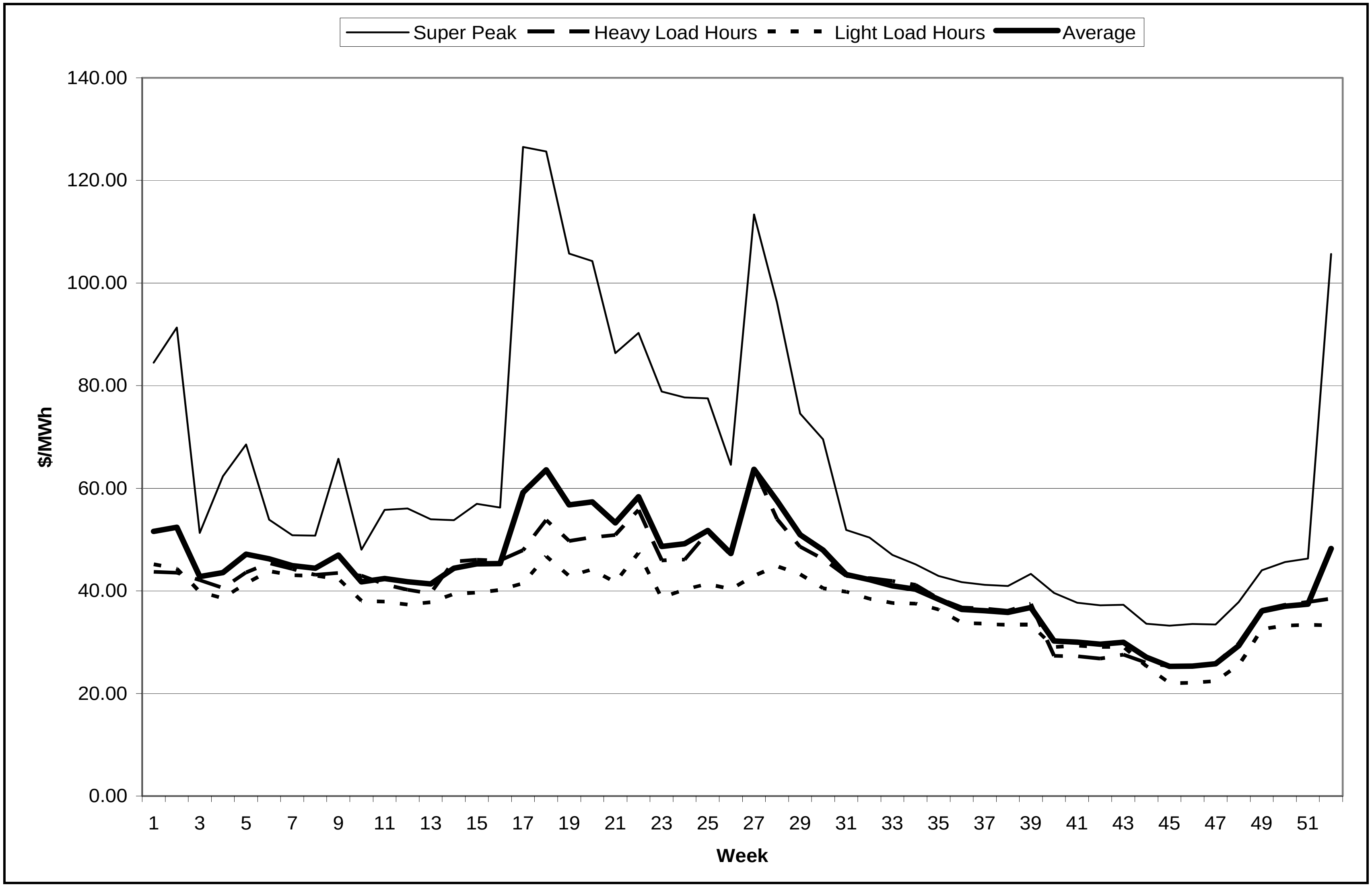
Hourly prices were converted to weekly averages for each water year. The result was a 50-water year by 52-week table of power values for each sub-period. The average weekly prices are shown in Figure D-2.

D.3.4. Determining Energy Benefits for Each

For each project and each TEAM scenario, the TEAM output for weeks 21-35 from the without fish screens TEAM run and the TEAM output for weeks 1-20 and 36-52 from the with fish screens TEAM run were merged to produce composite TEAM output representing the TEAM scenario.

To determine the energy benefits associated with each TEAM scenario, an Excel spreadsheet called COMPARE was developed that utilized the composite TEAM output, along with the weekly energy values described in Section D.3.3. The composite TEAM output for each TEAM scenario includes a worksheet that provides project weekly generation for each of the three sub-periods (SP, HLH and LLH) over the entire hydrologic period used in the study. For each project, copies of this worksheet were moved into COMPARE for all TEAM scenarios including the base case (TEAM Scenario R01). Weekly energy values for all years in the hydrologic period were also loaded into COMPARE. With TEAM scenario worksheets and weekly energy values as input, COMPARE can determine the energy benefits associated with any two TEAM scenarios, as well as the difference in energy benefits between the two TEAM scenarios. For example, the TEAM scenario representing one unit out of service can be compared with the TEAM scenario representing no units out of service. In this case, COMPARE computes the energy benefits associated with each of the two TEAM scenarios, and also computes the impact on energy benefits that result from a unit being out of service.

Figure D-2. Average Weekly Price by Sub-Period



Benefits in COMPARE are calculated on a weekly time step for each sub-period and for each year in the hydrologic period. For each sub-period, the weekly benefits are averaged over the entire hydrologic period to obtain the average benefit for each week. The weekly average benefits for each of the three sub-periods are then summed to obtain the total weekly average benefits. The 52 weekly average benefits are then summed to obtain the hydrologic period average annual benefits.

For each of the four projects, Table D-2 shows the average annual benefits (or annual generation value) for each TEAM scenario required to simulate the base case and each repair strategy over the 20-year economic period of analysis. Also shown is the corresponding reduction in annual benefits from the base case (last column labeled “Reduction in Generation Value from Base Case”).

Table D-2. Average Annual Benefits for TEAM Scenarios

Run Pair Designation	Number of Operating Kaplans (K)	Number of Operating Propellers (P)	Number of Units Out of Service (U)	Annual Generation Value ($1,000)	Reduction in Generation Value From Base Case ($1,000)
COMPARE Results for John Day Project					
R01	16	0	0	408,855	----
R02	15	0	1	408,391	464
R03	14	0	2	407,602	1,253
R04	15	1	0	408,843	12
R05	14	1	1	408,368	487
R06	14	2	0	408,822	33
R07	13	2	1	408,333	522
R08	13	3	0	408,790	65
R09	12	3	1	408,292	563
R10	12	4	0	408,751	104
R11	11	4	1	408,235	620
R12	11	5	0	408,694	161
R13	10	5	1	408,156	699
R14	10	6	0	408,618	237
R15	9	6	1	408,048	807
R16	9	7	0	408,514	341
R17	8	7	1	407,875	980
R18	8	8	0	408,351	504
COMPARE Results for Lower Monumental Project					
R01	6	0	0	97,145	----
R02	5	0	1	95,869	1,276
R03	5	1	0	97,314	-170
COMPARE Results for Little Goose Project					
R01	6	0	0	96,286	----
R02	5	0	1	95,413	872
R03	5	1	0	96,640	-354
COMPARE Results for Lower Granite Project					
R01	6	0	0	95,785	----
R02	5	0	1	94,420	1,365
R03	5	1	0	96,097	-311

Table D-2 shows that for each Snake River project, there is a negative reduction in annual generation value under TEAM Run R03. In other words, if a failed turbine is repaired to propeller operation for the entire year, there is a gain in project generation value compared to the base case. This result occurs because, as shown in Table D-1, there is a gain in annual generation for each Snake River project under TEAM Run R03.

For each of the TEAM scenarios summarized in Table D-2, weekly average benefits from COMPARE were used to obtain the generation value for each week of the year. The weekly generation values from the various TEAM scenarios were then used to determine the week-by-week generation value for the base case and each Kaplan repair strategy over the 20-year economic period of analysis. For example, under Strategy B (failed turbine to become propeller type), a single Kaplan failure occurs at each Snake River project at the beginning of FY 2010. This strategy assumes that five months are required to repair the failed turbine to propeller operation and that propeller operation continues throughout the remainder of the period of analysis. The week-by-week generation values for Strategy B were obtained by combining the TEAM Scenario R02 weekly generation values for the period October 2009 - February 2010 with the TEAM Scenario R03 weekly generation values for the period March 2010 - September 2029, where TEAM Scenario R02 represents five operating Kaplan units, no operating propeller units, and one unit out of service, while TEAM Scenario R03 represents five operating Kaplan units, one operating propeller unit, and no units out of service.

After week-by-week generation values were obtained for the base case and each Kaplan repair strategy over the 20-year period of analysis, the results were used to determine the corresponding yearly generation values for each fiscal year in the 20-year period. These results were then used to determine, for each Kaplan repair strategy, the reduction in generation value from the base case. Table D-3 summarizes the results of this process for each of the four projects. The table values assume an energy inflation rate of 2% beginning in FY 2011.

Table D-3 shows that under Strategy A (failed turbine to remain Kaplan type), each Snake River project experiences a negative reduction in generation value from the base case in FY 2010, FY 2011 and FY 2013 and experiences a positive reduction in generation value from the base case in FY 2012. The negative reduction in generation value shown for FY 2010 and FY 2011 is the result of each failed turbine being repaired to propeller type over a three-month period and operating as a propeller for an 18-month period that spans those two years. The positive reduction in generation value shown for FY 2012 is the result of an 18-month outage that takes place to return the failed turbine to full Kaplan operation. The last three months of this outage occurs during October – December of FY 2013. The loss of one unit during this three-month period has little negative impact on project generation, since there is often insufficient flow during October – December to support operating all six units. To the contrary, with unit 3 out of service the more efficient units 4-6 move up in the unit loading order. Thus, it is entirely possible for each Snake River project to produce more generation (and generation value) during October – December with unit 3 out of service than with unit 3 in service. This is what accounts for the negative reduction in generation value during FY 2013 for each Snake River project.

Table D-3 shows that under Strategy B (failed turbine to become propeller type), each Snake River project experiences a negative reduction in generation value from the base case during each year of the 20-year period of analysis. This is the result of each failed turbine being repaired to propeller type over a five-month period and operating as a propeller throughout the remainder of the 20-year period of analysis.

Table D-3. Inflated Annual Reduction in Generation Value ($1,000) from Base Case

Kaplan Repair Strategy	Number of Turbine Failures	Year Number / Fiscal Year																			
		1 2010	2 2011	3 2012	4 2013	5 2014	6 2015	7 2016	8 2017	9 2018	10 2019	11 2020	12 2021	13 2022	14 2023	15 2024	16 2025	17 2026	18 2027	19 2028	20 2029
John Day Project																					
Strategy A	5	23	13	531	26	553	27	575	28	598	29	566	14	0	0	0	0	0	0	0	0
Strategy B	5	119	13	146	35	186	72	236	120	309	192	196	200	204	208	212	217	221	225	230	233
Strategy C	5	464	474	483	493	503	513	523	533	544	555	0	0	0	0	0	0	0	0	0	0
Strategy A	8	23	13	531	26	553	27	575	28	598	29	623	31	648	32	674	33	637	15	0	0
Strategy B	8	119	13	146	35	186	72	236	120	309	192	411	295	559	441	802	678	692	706	720	695
Strategy C	8	464	474	483	493	503	513	523	533	544	555	566	577	589	601	613	625	0	0	0	0
Lower Monumental Project																					
Strategy A	1	-163	-173	1,328	-13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy B	1	-163	-173	-177	-180	-184	-187	-191	-195	-199	-203	-207	-211	-215	-220	-224	-228	-233	-238	-242	-229
Strategy C	1	1,276	1,302	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Little Goose Project																					
Strategy A	1	-346	-361	908	-46	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy B	1	-346	-361	-368	-375	-383	-391	-398	-406	-415	-423	-431	-440	-449	-458	-467	-476	-486	-495	-505	-427
Strategy C	1	872	890	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lower Granite Project																					
Strategy A	1	-304	-317	1,421	-48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy B	1	-304	-318	-324	-330	-337	-344	-351	-358	-365	-372	-380	-387	-395	-403	-411	-419	-427	-436	-445	-376
Strategy C	1	1,365	1,393	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Appendix E
Economics

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E.1.0. Introduction

E.1.1. Purpose and Scope

The purpose of this appendix is to compare the economic merits of several repair strategies under consideration to address future failures of the blade adjustment mechanisms in 25 identical turbines installed in the John Day, Lower Monumental, Little Goose, and Lower Granite powerhouses. The results from several other report appendices serve as input to this appendix. The value of the generation produced by the four projects under each repair strategy was obtained from Appendix D, *Power Benefits*. The repair costs and repair schedules associated with each repair strategy were obtained from Appendix F, *Cost Estimates* and Appendix G, *Construction Schedules*, respectively.

E.1.2. Project Descriptions

John Day is a Portland District storage project located on the Columbia River (river mile 215.6) in the states of Oregon and Washington. Project operating purposes include flood control, hydropower, navigation, fish/wildlife, recreation, irrigation, and water quality. The project with units 1-16 was completed in 1971. Each powerhouse unit has a 115% overload rating of 155.25 MW (163.42 MVA @ 0.95 PF).

Lower Monumental, Little Goose, and Lower Granite are Walla Walla District run-of-river projects located on the Snake River (river miles 41.6, 70.3 and 107.5, respectively) in the state of Washington. Operating purposes for all three projects include hydropower, navigation, fish/wildlife, recreation, irrigation, and water quality. The initial Lower Monumental and Little Goose projects with units 1-3 were completed in 1970, while the initial Lower Granite project with units 1-3 was completed in 1975. The addition of units 4-6 at all three projects was completed in 1978. Each powerhouse unit at all three projects has a 115% overload rating of 155.25 MW (163.42 MVA @ 0.95 PF).

The 25 identical Kaplan turbines installed in John Day units 1-16 and in units 1-3 at the three Snake River projects were designed and manufactured by Baldwin-Lima-Hamilton (BLH), while the nine identical Kaplan turbines installed in units 4-6 at the three Snake River projects were designed and manufactured by Allis-Chalmers (AC). Recent failures have occurred in the blade adjustment mechanisms of the 25 BLH turbines. Several repair strategies are being considered for addressing future such failures, which are described below.

E.1.3. Study Participants

This appendix was prepared by the Hydropower Analysis Center (HAC). Mike Egge performed the energy and economic analyses and drafted the appendix text, tables, and figures. Non-HAC participants included: (1) George Medina, Portland District, who served as Project Manager; (2) Sonja Dodge, Northwestern Division Water Management, who performed the Hydro System Seasonal Regulation (HYSSR) simulation study and provided model flow and forebay elevation input for the Turbine Energy Analysis Model (TEAM); (3) Dan Watson, Hydroelectric Design Center (HDC), who provided unit performance data, schedules, and cost estimates; and (4) John Johannis, Bonneville Power Administration (BPA), who provided the power values used in estimating hydropower benefits.

E.1.4. Repair Strategies Evaluated

This study evaluated three repair strategies for addressing future failures of the blade adjustment mechanism in the BLH Kaplan turbines at John Day, Lower Monumental, Little Goose, and Lower Granite. Under each strategy, the John Day evaluation analyzed two different Kaplan failure scenarios (five failures and eight failures over the economic period of analysis, where successive failures were assumed to occur 24 months apart), while each Snake River project evaluation analyzed one Kaplan failure scenario (one failure over the economic period of analysis). For each repair strategy, the initial Kaplan failure was assumed to occur in FY 2010, the first year in the economic period of analysis (assumed to be 20 years in length).

The Kaplan repair strategies, along with the study base case, are briefly described below.

1. **Base Case.** The base case assumes there are no Kaplan turbine failures over the economic period of analysis. The base case is used to economically compare the merits of the three repair strategies. For each strategy, project generation benefits and repair costs are compared to the project generation benefits of the base case.

2. **Strategy A: Failed Turbine to Remain Kaplan Type.** Under this strategy, a failed turbine is repaired to operate temporarily as a propeller type until permanent repairs can be commenced to return the turbine to full Kaplan operation. The analysis for Strategy A assumes that three months is required to repair the failed turbine to propeller operation, that propeller operation continues for 18 months, and that an additional 18 months is required to return the turbine to full Kaplan operation.

3. **Strategy B: Failed Turbine to Become Propeller Type.** Under this strategy, a failed turbine is repaired to operate as a propeller type on an indefinite basis. The analysis for Strategy B assumes that five months is required to repair the failed turbine to propeller operation and that propeller operation continues throughout the remainder of the 20-year period of analysis.

4. **Strategy C: Failed Turbine to Remain Kaplan Type with IDIQ.** This strategy is similar to Strategy A in that it returns a failed turbine to full Kaplan operation. However, the failed turbine is not repaired to operate temporarily as a propeller type as in Strategy A. Instead, Strategy C uses an Indefinite Delivery Indefinite Quantity (IDIQ) contract, which reduces the amount of time (to 24 months) required to return the failed turbine to full Kaplan operation compared to Strategy A.

Figures G-5 through G-9 in Appendix G, *Construction Schedules*, provide graphical depictions of the various Kaplan repair strategies for John Day and each of the three Snake River projects.

E.1.5. Procedure

The development of project generation benefits for this study included the following steps:

- Run the HYSSR model to obtain a sequential stream flow regulation for John Day, Lower Monumental, Little Goose, and Lower Granite projects for the period from August 1928 through July 1978. For each project, determine weekly average releases and reservoir elevations for this 50-year hydrologic period of record.

- For each project, input project operational data (including HYSSR flows and reservoir elevations, turbine-generator performance, unit loading orders, unit maintenance schedules, spill for fish requirements and powerhouse minimum flow requirements) into TEAM, used to estimate project energy generation output for each year and week in the 50-year hydrologic period of record.
- For each project, run TEAM for each scenario (combination of operating Kaplan turbines, operating propeller turbines and units out of service) required to simulate the base case and each Kaplan repair strategy over the 20-year economic period of analysis.
- Determine average weekly power values from BPA supplied data for super-peak (SP) hours, heavy-load hours (HLH), and light-load hours (LLH) for each week in the 50-year hydrologic period of record.
- For each project, use the COMPARE spreadsheet to determine the value of generation for each scenario required to simulate the base case and each Kaplan repair strategy over the 20-year economic period of analysis.
- For each project, input yearly value of generation and repair cost data into the economics spreadsheet, then determine for each Kaplan repair strategy the present value (to FY 2010) of the net benefits compared to the base case.
- Conduct sensitivity analyses on each Kaplan repair strategy.

The first five steps listed above are described in Appendix D*, Power Benefits,* while the remaining two steps are described in this appendix.

Some parts of the study analysis were performed using spreadsheet software. Arithmetic operations and totals were taken to full decimal accuracy within the spreadsheet. Tables found within this report have been rounded to a specified level of accuracy after the mathematical computations have been performed; therefore, rounded totals may not equal the summation of rounded values.

E.2.0. Economic Analysis

E.2.1. Overview

The economic analysis performed for this study consisted of comparing project generation benefits and repair costs under each repair strategy with the project generation benefits of the base case. This comparison was performed separately for each of the four study projects. The strategy which produced the least cost or most benefit (i.e., the highest net present value (NPV) relative to the base case) was considered to be the best strategy from an economic perspective. The economic analysis was carried out using a spreadsheet model. A description of the spreadsheet operation, input and output is presented in Section E.2.3.

E.2.2. Key Assumptions

The following is a list of the key assumptions that were made with respect to the economic analysis for this study:

- A detailed energy production model that included turbine performance, maintenance schedules, and unit loading orders.
- Turbine performance, both with and without fish screens, for each of the three turbine types modeled in the study (BLH Kaplan, AC Kaplan, and fixed-blade propeller).
- 50-year simulated operation with resultant hydrologic flows.
- Energy generation separated into three parts: SP, HLH (on-peak), and LLH (off-peak).
- Power price forecasts over the long-term hydrologic period broken into SP, HLH (on-peak), and LLH (off-peak).
- 20-year economic period of analysis (beginning in FY 2010).
- 13% discount rate.
- Repair cost estimates for each turbine repair strategy.
- 15% cost contingency.
- 2% inflation rate on costs.
- 4.625% interest during construction.
- 2% inflation rate on energy values.

E.2.3. Economic Analysis Spreadsheet

To evaluate the overall NPV of the three Kaplan repair strategies, a spreadsheet model was set up to incorporate relevant factors, including interest rate (rate of return), period of analysis, assumed inflation rates, expected impacts to the value of generation (gains/losses relative to the base case) from implementing a particular repair strategy, and repair costs for each repair strategy. A separate version of the model was set up for each of the four study projects.

The spreadsheet model used Excel functions to compute the NPV for the base case and each alternative case (repair strategy), as well as the NPV of each alternative case compared to the base case. The inputs into the computations were entered into the following two worksheets; these worksheets are described in the following sections.

- **IRR_Master**: Acts as a control sheet to select study cases for comparison and for the input of specific values used in the evaluation. Provides NPV results for the base case and alternative case as well as the incremental NPV for the alternative case compared to the base case.
- **Generic_Annual_GT**: Contains turbine repair costs and any miscellaneous costs, as well as the expected value of generation impacts of the alternative case relative to the base case.

E.2.3.1. IRR_Master Worksheet

Figure E-1 shows an example of the data input into the IRR_Master worksheet[5]. User inputs are shaded blue and are described in Table E-1.

[5] The economic model was originally developed for use in powerhouse rehabilitation studies (involving, e.g., turbine replacement, generator rewind, transformer replacement). For these studies, the NPV and internal rate of return (IRR) were key calculations used in comparing the economic merits of the rehabilitation alternatives. Recent studies have used only NPV calculations when making these comparisons. As a result, economic comparison of the repair strategies in this study is based solely on NPV.

Figure E-1. IRR_Master Worksheet Inputs

John Day IRR & NPV

	Rate	Base Year for Inflation
IDC	4.625%	
Assumed Discount Rate	13.000%	
Cost Inflation	2.0%	2010
Energy Inflation	2.0%	2010

Base Case		First Cost Year	First On Line
Turbine/Generator Combination	Base Case (No Kaplan Failures)	2010	2010
Transformer Combination	Not Used	2010	2010
Alternative Case		First Cost Year	First On Line
Turbine/Generator Combination	Strategy A8: Temp. Prop. (8 Failures)	2010	2010
Transformer Combination	Not Used	2010	2010

Project Year -->	1	2	3	4	5
Year (Oct-Sept) -->	2010	2011	2012	2013	2014

Years for IRR & NPV	20

E.2.3.2. <u>Generic_Annual_GT Worksheet</u>

Cost and benefit (value of generation) stream data are entered into tables contained in the Generic_Annual_GT worksheet. Up to 25 years of data can be entered for up to 29 different alternatives. The table areas shaded blue, pink, orange, red and green designates user input areas. The numbers above the pink, orange, red and green areas refer to the study year. Since the period of analysis for this study begins in FY 2010, study year 1 was used to designate FY 2010.

The **blue** area in the first worksheet table (see Figure E-2) is where the name and description for each alternative is entered. These are only entered in the first table and are replicated in the remaining tables. The alternative names and descriptions are used in the IRR_Master worksheet to select the desired components for the base and alternative cases.

There are two table areas where costs associated with an alternative are entered. Construction, acquisition and installation costs are entered into the **pink** area, while miscellaneous costs are entered into the **red** area. Costs entered into either area should be entered in constant dollars (no inflation). Costs entered into the pink area **are subject to interest during construction**, while costs entered into the red area **are NOT subject to interest during construction**.

Table E-1. Input for IRR_Master Worksheet

Input Item	Description
IDC Rate	Interest rate used to calculate interest during construction
Assumed Discount Rate	Interest rate used for NPV calculation
Cost Inflation	Annual inflation rate on turbine and generator costs
Base Year Inflation	Base year for cost inflation (inflation begins the following year)
Energy Inflation	Annual inflation rate on outage costs and benefits
Base Year Inflation	Base year for energy inflation (inflation begins the following year)
Base Case	
Turbine/Generator Combination	Turbine/generator option used in Base Case (loads data from worksheet Generic_Annual_GT for Base Case)
First Cost Year	Sets first year of cost/benefit stream data (although says “Cost”, applies to both benefits and costs) for turbine/generator option in Base Case from worksheet Generic_Annual_GT (e.g. if this value was set to 2010, year 1 of data on Generic_Annual_GT would be 2010)
First On Line	Originally used to determine when debt retirement began for Base Case turbine/generator – no longer used, debt retirement begins when benefits increase or cost stream goes to 0.
Transformer Combination	Transformer option used in Base Case (loads data from worksheet Generic_Annual_Trans for Base Case) – not applicable for this study
First Cost Year	Sets first year of cost/benefit stream data (although says “Cost”, applies to both benefits and costs) for transformer option in Base Case from Generic_Annual_Trans (e.g., if this value was set to 2010, year 1 of data on Generic_Annual_Trans would be 2010) – not applicable for this study
First On Line	Originally used to determine when debt retirement began for Base Case transformer – not applicable for this study
Alternative Case	
Turbine/Generator Combination	Turbine/generator option used in Alternative Case (loads data from worksheet Generic_Annual_GT for Alternative Case)
First Cost Year	Sets first year of cost/benefit stream data (although says “Cost”, applies to both benefits and costs) for turbine/generator option in Alternative Case from worksheet Generic_Annual_GT (e.g. if this value was set to 2010, year 1 of data on Generic_Annual_GT would be 2010)
First On Line	Originally used to determine when debt retirement began for Alternative Case turbine/generator – No longer used, debt retirement begins when benefits increase or cost stream goes to 0.
Transformer Combination	Transformer option used in Alternative Case (loads data from worksheet Generic_Annual_Trans for Alternative Case) – not applicable for this study
First Cost Year	Sets first year of cost/benefit stream data (although says “Cost” applies to both benefits and costs) for transformer option in Alternative Case from Generic_Annual_Trans (e.g. if this value was set to 2010, year 1 of data on Generic_Annual_Trans would be 2010) – not applicable for this study
First On Line	Originally used to determine when debt retirement began for Alternative Case transformer – not applicable for this study
Year (Oct-Sept) -->	Starting year for evaluation
Years for IRR & NPV	Number of years from first year to use in NPV and IRR calculation.

Repair costs for each turbine repair strategy were developed by HDC (see Appendix F, *Cost Estimates*) and expressed as yearly estimates so that they could be entered into the pink area of worksheet Generic_Annual_GT. The Kaplan repair study did not use the red area of the worksheet. Figure E-2 summarizes the yearly repair costs that served as input to the economic analysis spreadsheet.

There are two table areas where benefits (value of generation) impacts associated with an alternative are entered. Benefits attributable to powerhouse rehabilitation (e.g., benefits gained through an increase in unit efficiency and / or capacity) are entered in the **green** area located below the red area. The base case value of generation is added to each value in this table to arrive at the corresponding table located above the red area. This table, which also has a **green** area, represents the project total value of generation under each alternative, not taking into account unit outages. Outage impacts (costs) to the value of generation when a unit is out of service for installation / rehabilitation or has failed and is not repaired are entered into the **orange** area. The data values entered into the green and orange areas are based on TEAM and COMPARE output (see Appendix D, *Power Benefits*) and should be entered in constant dollars (no inflation). To determine the yearly net value of generation associated with a given alternative, the IRR_Master worksheet subtracts the yearly value in the orange area from the yearly value in the green area (located above the red area).

TEAM and COMPARE were used to develop yearly gains / losses, (compared to the base case) in the value of project generation under each turbine repair strategy. Since there was no increase in unit efficiency and / or capacity under any repair strategy, it was decided to enter the combined impacts to the value of generation (from unit outages and once a unit is back in service following the completion of turbine repairs) in the green area located below the red area. Consequently, the Kaplan repair study did not use the orange area of the worksheet. Figure E-3 summarizes the yearly generation value impacts that served as input to the economic analysis spreadsheet.

Figure E-2. Repair Costs ($1,000) in Generic_Annual_GT Worksheet

John Day Project

Turbine Repair Cases	Turbine Repair Cost																			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Base Case (No Kaplan Failures)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy A5: Temp. Prop. (5 Failure	171	700	1,635	1,100	1,635	1,100	1,635	1,100	1,635	1,100	1,464	400	0	0	0	0	0	0	0	0
Strategy B5: Perm. Prop. (5 Failure	245	0	245	0	245	0	245	0	245	0	0	0	0	0	0	0	0	0	0	0
Strategy C5: Perm. Kaplan (5 Failu	1,051	1,453	1,051	1,453	1,051	1,453	1,051	1,453	1,051	1,453	0	0	0	0	0	0	0	0	0	0
Strategy A8: Temp. Prop. (8 Failure	171	700	1,635	1,100	1,635	1,100	1,635	1,100	1,635	1,100	1,635	1,100	1,635	1,100	1,635	1,100	1,464	400	0	0
Strategy B8: Perm. Prop. (8 Failure	245	0	245	0	245	0	245	0	245	0	245	0	245	0	245	0	0	0	0	0
Strategy C8: Perm. Kaplan (8 Failu	1,051	1,453	1,051	1,453	1,051	1,453	1,051	1,453	1,051	1,453	1,051	1,453	1,051	1,453	1,051	1,453	0	0	0	0

Lower Monumental, Little Goose, Lower Granite Projects

Turbine Repair Cases	Turbine Repair Cost																			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Base Case (No Kaplan Failures)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy A: Temp. Prop. (1 Failure)	171	700	1,464	400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy B: Perm. Prop. (1 Failure)	245	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy C: Perm. Kaplan (1 Failure	1,051	1,453	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure E-3. Value of Generation Impacts ($1,000) in Generic_Annual_GT Worksheet

John Day Project

Base Case Gen. Value ($1,000) 408,855 All Kaplan Units With No Unit Failures

Generation Value Impacts (Gain / Loss Over Base Case)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Base Case (No Kaplan Failures)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy A5: Temp. Prop. (5 Failure	-23	-12	-511	-25	-511	-25	-511	-25	-511	-25	-464	-11	0	0	0	0	0	0	0	0
Strategy B5: Perm. Prop. (5 Failure	-119	-12	-140	-33	-172	-65	-209	-104	-263	-161	-161	-161	-161	-161	-161	-161	-161	-161	-161	-160
Strategy C5: Perm. Kaplan (5 Failu	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	0	0	0	0	0	0	0	0	0	0
Strategy A8: Temp. Prop. (8 Failure	-23	-12	-511	-25	-511	-25	-511	-25	-511	-25	-511	-25	-511	-25	-511	-25	-464	-11	0	0
Strategy B8: Perm. Prop. (8 Failure	-119	-12	-140	-33	-172	-65	-209	-104	-263	-161	-337	-237	-440	-341	-608	-504	-504	-504	-504	-477
Strategy C8: Perm. Kaplan (8 Failu	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	-464	0	0	0	0

Lower Monumental Project

Base Case Gen. Value ($1,000) 97,145 All Kaplan Units With No Unit Failures

Generation Value Impacts (Gain / Loss Over Base Case)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Base Case (No Kaplan Failures)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy A: Temp. Prop. (1 Failure)	163	170	-1,276	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy B: Perm. Prop. (1 Failure)	163	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	157
Strategy C: Perm. Kaplan (1 Failure	-1,276	-1,276	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Little Goose Project

Base Case Gen. Value ($1,000) 96,286 All Kaplan Units With No Unit Failures

Generation Value Impacts (Gain / Loss Over Base Case)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Base Case (No Kaplan Failures)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy A: Temp. Prop. (1 Failure)	346	354	-872	43	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy B: Perm. Prop. (1 Failure)	346	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	293
Strategy C: Perm. Kaplan (1 Failure	-872	-872	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Lower Granite Project

Base Case Gen. Value ($1,000) 95,785 All Kaplan Units With No Unit Failures

Generation Value Impacts (Gain / Loss Over Base Case)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Base Case (No Kaplan Failures)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy A: Temp. Prop. (1 Failure)	304	311	-1,365	46	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Strategy B: Perm. Prop. (1 Failure)	304	311	311	311	311	311	311	311	311	311	311	311	311	311	311	311	311	311	311	258
Strategy C: Perm. Kaplan (1 Failure	-1,365	-1,365	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

E.2.3.3. <u>Calculation of NPV and IRR</u>

Once all input data has been entered into the IRR_Master and Generic_Annual_GT worksheets, the NPV and IRR are calculated for the base case and the selected alternative case. Also calculated are the net NPV and IRR for the alternative case minus the base case. As noted in Section E.2.3.1, recent studies have used only the NPV calculations when comparing the economic merits of various alternatives. Since NPV calculations are based on the specified/desired rate of return, the IRR calculations are no longer considered necessary when comparing alternatives. In addition, the economic analysis spreadsheet uses the Excel IRR function for making IRR calculations. Depending on the costs and benefits streams, the IRR function may not return a value and a “#DIV/0!” may be shown. Figure E-4 displays sample NPV and IRR calculations for this study. The economic comparison of the Kaplan repair strategies was based solely on the NPV calculations.

Figure E-4. Sample NPV Calculations

John Day IRR & NPV

	Rate	Base Year for Inflation
IDC	4.625%	
Assumed Discount Rate	13.000%	
Cost Inflation	2.0%	2010
Energy Inflation	2.0%	2010

Base Case		First Cost Year	First On Line
Turbine/Generator Combination	Base Case (No Kaplan Failures)	2010	2010
Transformer Combination	Not Used	2010	2010
Alternative Case		First Cost Year	First On Line
Turbine/Generator Combination	Strategy A8: Temp. Prop. (8 Failures)	2010	2010
Transformer Combination	Not Used	2010	2010

Project Year -->	1	2	3	4	5
Year (Oct-Sept) -->	2010	2011	2012	2013	2014

Years for IRR & NPV: 20

	IRR	NPV
Base Case: G/T-Base Case (No Kaplan Failures), Transformer-Not Used	**#DIV/0!**	**$3,237,560**
Alternative: G/T-Strategy A8: Temp. Prop. (8 Failures), Transformer-Not Used	**#DIV/0!**	**$3,226,629**
Net NPV (Alternative MINUS Base Case)	**#DIV/0!**	**($10,931)**

E.2.4. Economic Analysis Results for Repair Strategies

Tables E-2 through E-5 summarize for John Day, Lower Monumental, Little Goose, and Lower Granite respectively, the PV repair costs, PV value of generation, and NPV (PV value of generation - PV repair costs) for the base case and each turbine repair strategy. These same calculations are shown for each turbine repair strategy relative to the base case. Two failure scenarios were analyzed for JDA (five and eight turbine failures over the 20-year economic period of analysis), while each Snake River project analysis assumed one turbine failure over the 20-year economic period of analysis. Table E-6 averages the corresponding results from Tables E-3 through E-5 to provide a summary representing all three Snake River projects combined.

A review of the last column in Tables E-2 through E-5 shows that for each of the four study projects, Strategy B (failed turbine to become propeller type) produces the highest NPV relative to the base case. In the case of JDA, the highest NPV (or least negative NPV) is achieved under the five turbines failure scenario. The main reason strategy B is the best repair strategy from an economic perspective for all four study projects is that the turbine repair costs for Strategy B are much lower (by a factor of about 10) than the turbine repair costs for Strategy A and Strategy C.

In the case of the Snake River projects, another factor that favors Strategy B is the positive PV value of generation (compared to the base case), which results in a positive NPV for each project. As noted in Appendix D, *Power Benefits*, when unit 3 at a Snake River project operates nearly the entire 20-year economic period of analysis as a propeller (as in Strategy B), it is placed last in the unit loading order, thereby moving the more efficient units 4-6 up in the unit loading order. This produces gains in project generation (and in the value of project generation) during each year in the 20-year economic period of analysis. These gains more than offset the loss in generation (and value of generation) that results when unit 3 is out of service for five months due to a turbine failure.

E.2.5. Sensitivity Analysis Results for Repair Strategies

The economic analysis performed for this study identified Strategy B (failed turbine to become propeller type) as the best repair strategy from an economic perspective for John Day and each of the three Snake River projects. Since the economic analysis is based on a number of key assumptions (see Section E.2.2.), a sensitivity analysis was performed to determine if changing the value of a key assumption would impact which repair strategy is identified as the best repair strategy at each study project.

The sensitivity analysis considered the following four economic analysis key assumptions:

- Discount rate: 13 percent
- Energy inflation: 2 percent
- Cost inflation: 2 percent
- Per failure annual repair costs (uninflated): $2,735,000 for Strategy A
$245,000 for Strategy B
$2,504,000 for Strategy C

The sensitivity analysis consisted of repeating the economic analysis with one key assumption changed and all other key assumptions left unchanged. This process was repeated four times, once for each of the four key assumptions listed above. The changes that were made to these key assumptions for the sensitivity analysis are listed below:

- Discount rate: 4.625 percent (Corps' discount rate for FY 2009)
- Energy inflation: 3 percent
- Cost inflation: 3 percent
- Per failure annual repair costs (uninflated): $1,735,000 for Strategy A
$490,000 for Strategy B
$2,504,000 for Strategy C

For Strategy A, the sensitivity analysis reduced repair costs by $1,000,000 (to $1,735,000) to reflect the situation where the repairs are performed by Corps' personnel rather than being performed by a contractor. For Strategy B, the sensitivity analysis doubled repair costs (to $490,000) to reflect the situation where more damage results from the turbine failure than was assumed in the original repair cost estimate. For Strategy C, the sensitivity analysis assumed the same repair costs that were assumed in the economic analysis.

The sensitivity analysis results for John Day are summarized in Table E-7, while the sensitivity analysis average results for Lower Monumental, Little Goose, and Lower Granite are summarized in Table E-8. Both tables contain five columns of results, where each column summarizes NPV (PV value of generation – PV repair costs) for each turbine repair strategy relative to the base case. The first of these columns represents the NPV results from the original economic analysis, where the Table E-7 results match those shown in the last column of Table E-2 and the Table E-8 results match those shown in the last column of Table E-6. The remaining columns of NPV results summarized in Tables E-7 and E-8 represent the results that were obtained when the economic analysis was repeated after a change was made in one of the key assumptions. The key assumption that was changed is highlighted in green in the top row of each column.

The sensitivity analysis results summarized in Tables E-7 and E-8 show that when any of the four key assumptions is changed as described above, the updated economic analysis reaches the same conclusions as those reached in the original economic analysis: Strategy B produces the highest NPV relative to the base case for each study project. In the case of JDA, the highest NPV (or least negative NPV) is achieved under the five turbine failures scenario. Thus, Strategy B remains the best repair strategy from an economic perspective for all four study projects.

Table E-2. PV of John Day Repair Costs and Value of Generation by Repair Strategy

Strategy	Strategy Description	Date of Initial Unit Failure	Number of Unit Failures	Downtime Per Unit Failure (Months)	Duration Between Unit Failures (Months)	PV Repair Costs ($1,000)	PV Generation ($1,000)	NPV ($1,000)	Relative to Base Case: PV Rep Costs ($1,000)	Relative to Base Case: PV Gen ($1,000)	Relative to Base Case: NPV ($1,000)
Base Case	There are no Kaplan unit failures throughout the 20-year period of analysis.	N / A	N / A	N / A	N / A	0	3,237,560	3,237,560	----	----	----
Strategy A5	A failed Kaplan unit is temporarily repaired to fixed blade propeller operation until repairs to full Kaplan operation can be commenced.	FY 10	5	21 (3 + 18)	24	7,349	3,236,219	3,228,869	7,349	-1,341	-8,691
Strategy B5	A failed Kaplan unit is permanently repaired to fixed blade propeller operation.	FY 10	5	5	24	777	3,236,545	3,235,769	777	-1,015	-1,791
Strategy C5	A failed Kaplan unit is permanently repaired to full Kaplan operation using an IDIQ type contract.	FY 10	5	24	24	8,696	3,234,855	3,226,159	8,696	-2,705	-11,401
Strategy A8	A failed Kaplan unit is temporarily repaired to fixed blade propeller operation until repairs to full Kaplan operation can be commenced.	FY 10	8	21 (3 + 18)	24	9,240	3,235,868	3,226,629	9,240	-1,692	-10,931
Strategy B8	A failed Kaplan unit is permanently repaired to fixed blade propeller operation.	FY 10	8	5	24	974	3,235,993	3,235,019	974	-1,567	-2,541
Strategy C8	A failed Kaplan unit is permanently repaired to full Kaplan operation using an IDIQ type contract.	FY 10	8	24	24	11,825	3,234,159	3,222,335	11,825	-3,401	-15,225

Notes: Figures G-1 through G-4 in **Appendix G, *Construction Schedules*** present graphical depictions of the base case and the Kaplan repair strategies.

The study analysis assumes the following JDA units experience turbine failures: 4, 10, 8, 14, 11 (for five unit failures), and 4, 10, 8, 14, 11, 6, 3, 15 (for eight turbine failures), where units are listed in the order in which they are assumed to fail. The units selected to fail were chosen on a random basis.

For Strategies A5 and A8, it is assumed that 3 months is required to repair a failed unit to temporary fixed blade propeller operation. Propeller operation is assumed to take place for 18 months, after which repairs (assumed to require an additional 18 months) are commenced to return the unit to full Kaplan operation.

The annual repair costs and annual value of generation are inflated at two percent.

Per failure uninflated repair costs for each Kaplan repair strategy are developed in **Appendix F, *Cost Estimates***. Each estimate includes a contract contingency of 15 percent. Each estimate also includes non-contract costs (20 percent for Strategies A and C, and 50 percent for Strategy B). Non-contract costs include engineering and design (E&D), project management (PM), contracting (C), engineering during construction (EDC), supervision and administration (S&A), and project support (PS).

Table E-3. PV of Lower Monumental Repair Costs and Value of Generation by Repair Strategy

Strategy	Strategy Description	Date of Initial Unit Failure	Number of Unit Failures	Downtime Per Unit Failure (Months)	Duration Between Unit Failures (Months)	PV Repair Costs ($1,000)	PV Generation ($1,000)	NPV ($1,000)	Relative to Base Case PV Rep Costs ($1,000)	Relative to Base Case PV Gen ($1,000)	Relative to Base Case NPV ($1,000)
Base Case	There are no Kaplan unit failures throughout the 20-year period of analysis.	N / A	N / A	N / A	N / A	0	769,251	769,251	----	----	----
Strategy A	A failed Kaplan unit is temporarily repaired to fixed blade propeller operation until repairs to full Kaplan operation can be commenced.	FY 10	1	21 (3 + 18)	24	2,124	768,618	766,494	2,124	-633	-2,757
Strategy B	A failed Kaplan unit is permanently repaired to fixed blade propeller operation.	FY 10	1	5	24	231	770,587	770,356	231	1,336	1,105
Strategy C	A failed Kaplan unit is permanently repaired to full Kaplan operation using an IDIQ type contract.	FY 10	1	24	24	2,178	767,102	764,924	2,178	-2,149	-4,327

Notes: Figure G-5 in **Appendix G, *Construction Schedules*** presents graphical depictions of the base case and the Kaplan repair strategies, where each repair strategy assumes that Unit 3 experiences a turbine failure.

For Strategy A, it is assumed that 3 months is required to repair a failed unit to temporary fixed blade propeller operation. Propeller operation is assumed to take place for 18 months, after which repairs (assumed to require an additional 18 months) are commenced to return the unit to full Kaplan operation.

The annual repair costs and annual value of generation are inflated at two percent.

Per failure uninflated repair costs for each Kaplan repair strategy are developed in **Appendix F, *Cost Estimates***. Each estimate includes a contract contingency of 15 percent. Each estimate also includes non-contract costs (20 percent for Strategies A and C, and 50 percent for Strategy B). Non-contract costs include engineering and design (E&D), project management (PM), contracting (C), engineering during construction (EDC), supervision and administration (S&A), and project support (PS).

Table E-4. PV of Little Goose Repair Costs and Value of Generation by Repair Strategy

Strategy	Strategy Description	Date of Initial Unit Failure	Number of Unit Failures	Downtime Per Unit Failure (Months)	Duration Between Unit Failures (Months)	PV Repair Costs ($1,000)	PV Generation ($1,000)	NPV ($1,000)	Relative to Base Case: PV Rep Costs ($1,000)	Relative to Base Case: PV Gen ($1,000)	Relative to Base Case: NPV ($1,000)
Base Case	There are no Kaplan unit failures throughout the 20-year period of analysis.	N / A	N / A	N / A	N / A	0	762,448	762,448	----	----	----
Strategy A	A failed Kaplan unit is temporarily repaired to fixed blade propeller operation until repairs to full Kaplan operation can be commenced.	FY 10	1	21 (3 + 18)	24	2,124	762,436	760,312	2,124	-12	-2,136
Strategy B	A failed Kaplan unit is permanently repaired to fixed blade propeller operation.	FY 10	1	5	24	231	765,236	765,005	231	2,787	2,556
Strategy C	A failed Kaplan unit is permanently repaired to full Kaplan operation using an IDIQ type contract.	FY 10	1	24	24	2,178	760,980	758,802	2,178	-1,469	-3,647

Notes: Figure G-5 in **Appendix G, *Construction Schedules*** presents graphical depictions of the base case and the Kaplan repair strategies, where each repair strategy assumes that Unit 3 experiences a turbine failure.

For Strategy A, it is assumed that 3 months is required to repair a failed unit to temporary fixed blade propeller operation. Propeller operation is assumed to take place for 18 months, after which repairs (assumed to require an additional 18 months) are commenced to return the unit to full Kaplan operation.

The annual repair costs and annual value of generation are inflated at two percent.

Per failure uninflated repair costs for each Kaplan repair strategy are developed in **Appendix F, *Cost Estimates***. Each estimate includes a contract contingency of 15 percent. Each estimate also includes non-contract costs (20 percent for Strategies A and C, and 50 percent for Strategy B). Non-contract costs include engineering and design (E&D), project management (PM), contracting (C), engineering during construction (EDC), supervision and administration (S&A), and project support (PS).

Table E-5. PV of Lower Granite Repair Costs and Value of Generation by Repair Strategy

Strategy	Strategy Description	Date of Initial Unit Failure	Number of Unit Failures	Downtime Per Unit Failure (Months)	Duration Between Unit Failures (Months)	PV Repair Costs ($1,000)	PV Generation ($1,000)	NPV ($1,000)	Relative to Base Case: PV Rep Costs ($1,000)	Relative to Base Case: PV Gen ($1,000)	Relative to Base Case: NPV ($1,000)
Base Case	There are no Kaplan unit failures throughout the 20-year period of analysis.	N / A	N / A	N / A	N / A	0	758,486	758,486	----	----	----
Strategy A	A failed Kaplan unit is temporarily repaired to fixed blade propeller operation until repairs to full Kaplan operation can be commenced.	FY 10	1	21 (3 + 18)	24	2,124	758,048	755,924	2,124	-438	-2,562
Strategy B	A failed Kaplan unit is permanently repaired to fixed blade propeller operation.	FY 10	1	5	24	231	760,938	760,707	231	2,452	2,221
Strategy C	A failed Kaplan unit is permanently repaired to full Kaplan operation using an IDIQ type contract.	FY 10	1	24	24	2,178	756,187	754,009	2,178	-2,299	-4,477

Notes: Figure G-5 in **Appendix G, *Construction Schedules*** presents graphical depictions of the base case and the Kaplan repair strategies, where each repair strategy assumes that Unit 3 experiences a turbine failure.

For Strategy A, it is assumed that 3 months is required to repair a failed unit to temporary fixed blade propeller operation. Propeller operation is assumed to take place for 18 months, after which repairs (assumed to require an additional 18 months) are commenced to return the unit to full Kaplan operation.

The annual repair costs and annual value of generation are inflated at two percent.

Per failure uninflated repair costs for each Kaplan repair strategy are developed in **Appendix F, *Cost Estimates***. Each estimate includes a contract contingency of 15 percent. Each estimate also includes non-contract costs (20 percent for Strategies A and C, and 50 percent for Strategy B). Non-contract costs include engineering and design (E&D), project management (PM), contracting (C), engineering during construction (EDC), supervision and administration (S&A), and project support (PS).

Table E-6. PV of Snake River Projects Repair Costs and Value of Generation by Repair Strategy

Strategy	Strategy Description	Date of Initial Unit Failure	Number of Unit Failures	Downtime Per Unit Failure (Months)	Duration Between Unit Failures (Months)	PV Repair Costs ($1,000)	PV Generation ($1,000)	NPV ($1,000)	Relative to Base Case: PV Rep Costs ($1,000)	Relative to Base Case: PV Gen ($1,000)	Relative to Base Case: NPV ($1,000)
Base Case	There are no Kaplan unit failures throughout the 20-year period of analysis.	N / A	N / A	N / A	N / A	0	763,395	763,395	----	----	----
Strategy A	A failed Kaplan unit is temporarily repaired to fixed blade propeller operation until repairs to full Kaplan operation can be commenced.	FY 10	1	21 (3 + 18)	24	2,124	763,034	760,910	2,124	-361	-2,485
Strategy B	A failed Kaplan unit is permanently repaired to fixed blade propeller operation.	FY 10	1	5	24	231	765,587	765,356	231	2,192	1,961
Strategy C	A failed Kaplan unit is permanently repaired to full Kaplan operation using an IDIQ type contract.	FY 10	1	24	24	2,178	761,423	759,245	2,178	-1,972	-4,150

Notes: Figure G-5 in **Appendix G, *Construction Schedules*** presents graphical depictions of the base case and the Kaplan repair strategies, where each repair strategy assumes that Unit 3 experiences a turbine failure.

For Strategy A, it is assumed that 3 months is required to repair a failed unit to temporary fixed blade propeller operation. Propeller operation is assumed to take place for 18 months, after which repairs (assumed to require an additional 18 months) are commenced to return the unit to full Kaplan operation.

The annual repair costs and annual value of generation are inflated at two percent.

Per failure uninflated repair costs for each Kaplan repair strategy are developed in **Appendix F, *Cost Estimates***. Each estimate includes a contract contingency of 15 percent. Each estimate also includes non-contract costs (20 percent for Strategies A and C, and 50 percent for Strategy B). Non-contract costs include engineering and design (E&D), project management (PM), contracting (C), engineering during construction (EDC), supervision and administration (S&A), and project support (PS).

Results shown in table represent the average of the results obtained for each of the three Snake River projects.

Table E-7. NPV Sensitivity Analysis for John Day Project by Repair Strategy

Economic Parameter	Discount Rate Energy Inflation Cost Inflation Repair Costs	13% 2% 2% See Note 1)	4.625% 2% 2% See Note 1)	13% 3% 2% See Note 1)	13% 2% 3% See Note 1)	13% 2% 2% See Note 2)
Strategy	**Strategy Description**	**Economic Analysis NPV ($1,000)**	**Discount Rate SA NPV ($1,000)**	**Energy Inflation SA NPV ($1,000)**	**Cost Inflation SA NPV ($1,000)**	**Repair Costs SA NPV ($1,000)**
Base Case	No Kaplan unit failures throughout the 20-year period of analysis.	----	----	----	----	----
Strategy A5	A failed Kaplan unit is temporarily repaired to fixed blade propeller operation until repairs to full Kaplan operation can be commenced.	-8,691	-14,077	-8,759	-9,053	-6,003
Strategy B5	A failed Kaplan unit is permanently repaired to fixed blade propeller operation.	-1,791	-3,230	-1,871	-1,816	-2,568
Strategy C5	A failed Kaplan unit is permanently repaired to full Kaplan operation using an IDIQ type contract.	-11,401	-17,132	-11,500	-11,711	-11,401
Strategy A8	A failed Kaplan unit is temporarily repaired to fixed blade propeller operation until repairs to full Kaplan operation can be commenced.	-10,931	-20,970	-11,049	-11,559	-7,553
Strategy B8	A failed Kaplan unit is permanently repaired to fixed blade propeller operation.	-2,541	-5,616	-2,704	-2,590	-3,515
Strategy C8	A failed Kaplan unit is permanently repaired to full Kaplan operation using an IDIQ type contract.	-15,225	-27,900	-15,413	-15,846	-15,225

Notes: 1) The Kaplan Turbine Repair Study economic analysis assumes the following repair costs:

Per Failure Annual Repair Costs (Uninflated)	$2,735,000	for Repair Strategy A
	$245,000	for Repair Strategy B
	$2,504,000	for Repair Strategy C

2) The repair costs sensitivity analysis modifies the repair costs as described below:

Per Failure Annual Repair Costs (Uninflated)	$1,735,000	for Repair Strategy A (a $1,000,000 reduction in repair costs if COE personnel perform the repairs rather than having the repairs performed by a contractor)
	$490,000	for Repair Strategy B (a doubling of the repair costs if more damage results from the turbine failure than is assumed in the original repair cost estimate)
	$2,504,000	for Repair Strategy C (repair costs remain the same)

3) NPV results shown in table are relative to the base case.

Table E-8. NPV Sensitivity Analysis for Snake River Projects by Repair Strategy

Economic Parameter	**Discount Rate** **Energy Inflation** **Cost Inflation** **Repair Costs**	**13%** **2%** **2%** **See Note 1)**	**4.625%** **2%** **2%** **See Note 1)**	**13%** **3%** **2%** **See Note 1)**	**13%** **2%** **3%** **See Note 1)**	**13%** **2%** **2%** **See Note 2)**
Strategy	**Strategy Description**	**Economic Analysis NPV ($1,000)**	**Discount Rate SA NPV ($1,000)**	**Energy Inflation SA NPV ($1,000)**	**Cost Inflation SA NPV ($1,000)**	**Repair Costs SA NPV ($1,000)**
Base Case	There are no Kaplan unit failures throughout the 20-year period of analysis.	----	----	----	----	----
Strategy A	A failed Kaplan unit is temporarily repaired to fixed blade propeller operation until repairs to full Kaplan operation can be commenced.	-2,485	-3,142	-2,499	-2,520	-1,708
Strategy B	A failed Kaplan unit is permanently repaired to fixed blade propeller operation.	1,961	3,942	2,103	1,961	1,730
Strategy C	A failed Kaplan unit is permanently repaired to full Kaplan operation using an IDIQ type contract.	-4,150	-4,669	-4,159	-4,162	-4,150

Notes: 1) The Kaplan Turbine Repair Study economic analysis assumes the following repair costs:

Per Failure Annual Repair Costs	$2,735,000	for Repair Strategy A
(Uninflated)	$245,000	for Repair Strategy B
	$2,504,000	for Repair Strategy C

2) The repair costs sensitivity analysis modifies the repair costs as described below:

Per Failure Annual Repair Costs (Uninflated)	$1,735,000	for Repair Strategy A (a $1,000,000 reduction in repair costs if COE personnel perform the repairs rather than having the repairs performed by a contractor)
	$490,000	for Repair Strategy B (a doubling of the repair costs if more damage results from the turbine failure than is assumed in the original repair cost estimate)
	$2,504,000	for Repair Strategy C (repair costs remain the same)

3) NPV results shown in table are relative to the base case and represent the average of the NPV results obtained for each of the three Snake River projects.

Appendix F
Cost Estimates

Appendix F
Cost Estimates

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F.1.0. Costs for the Three Repair Strategies

There are three strategies analyzed in this report to repair a failed Kaplan unit. Strategy A is a standard contract repair. Strategy B is the permanent conversion of a Kaplan unit to a fixed blade propeller. Strategy C is similar to Strategy A except an innovative Indefinite Delivery Indefinite Quantity (IDIQ) contracting process will be used. Costs for repairing a broken Kaplan unit to full Kaplan function are based on the temporary repair of Lower Monumental unit 1 and the Kaplan repair of Lower Granite unit 2 and John Day unit 16 to full service, two units on which this work has already been performed. The conversion of a broken unit to permanent fixed-blade propeller operation is based on a best estimate of the work involved.

Non-contract costs such as engineering and design (E&D), project management, contracting, engineering during construction, supervision and administration (S&A), and project support are assumed to be about 20% of the contract cost for a full Kaplan repair. This is based on common estimates for other rehabilitation jobs of similar nature. For the smaller permanent conversion to a fixed blade propeller the non-contract cost are estimated to be greater than 20%. A contingency of approximately 15% of the repair cost is used for each of the three strategies to account for unforeseen circumstances.

F.2.0. Strategy A, Full Kaplan Repair by Regular Contract

After a mechanism failure has been determined, the initial actions would be to temporarily repair the unit to a fixed blade propeller. The project personnel would temporarily set the runner blades at 29 degrees immediately after failure (see Appendix C) by welding blocks on the runner to prevent movement. This temporary repair is expected to take 3 months (see Appendix G, Temporary Repair Schedule). The runner is then operated for a period of about 18 months in this temporary fixed blade mode. During this period, a contract to perform a full repair is to be assembled and awarded to a contractor. It is expected that the unit will be repaired to full Kaplan function over an 18-month period. The total time from failure to full Kaplan function will be about 39 months (see Appendix G, Strategy A).

F.2.1. Temporary Fixed-blade Repair

Table F-1 shows the expected labor hours and costs to perform a temporary repair to fixed blade operation and is based on the Lower Monumental unit 1 failure in spring of 2005. A cost of $80/hour is assumed for labor costs. This cost is also shown in Table F-3, Item No. 1, which shows the total estimated repair cost for Strategy A.

Table F-1. Temporary Fixed-blade Propeller Repair

Description		Labor Hours
Dewater Unit		
Head gates		30
Stop logs		30
Un-water & uncover		40
	Subtotal	100
Platform Install	Subtotal	100
Hub		
Remove oil		40
Lower hub cone		160
Reinstall hub cone		160
Refill with oil		40
	Subtotal	400
Blades		
Unstick blades		40
Set angle		40
	Subtotal	80
Blocks		
Machine blocks		120
Weld blocks to hub		800
Stainless steel on blades (Cav Resistant)		200
	Subtotal	1,120
Remove Platform & Water Unit	Subtotal	200
	Total Hours	2,000
	Labor Costs	$160,000
	Supplies and Material	$11,000
	Total Project Costs	**$171,000**

F.2.2. Estimate for Replacement of Spare Runner Parts

Replacement spare parts will be needed to maintain the necessary spare parts inventory for a future repair. A contract was awarded in 2007 to have spare parts fabricated for the John Day unit 16 repair. The estimate for spare parts for a possible future runner failure is based on this contract price with appropriate adjustments is presented in Table F-2. At the request of BPA, an attempt was made to identify the costs as they apply to the expense and capital budgets. This cost is included as Item No. 10 in Table F-3, which presents the total cost for Strategy A.

Table F-2. Spare Parts List

John Day Unit 16 Repair Parts		2007 Contract PRC ($)	Future Contract Est. Projected Oct 2009 ($)
Bid Item	**Description**		
1	Studs, Nuts & Washers for Runner Cone	8,324	8,990
2	**Inside & Outside Blade Mechanism Links*	*29,840*	*32,228*
3	**Link Pins and Keys for Blade Lever*	*11,966*	*12,924*
4	**Link Pins and Keys for Eye End*	*11,966*	*12,924*
5	**Blade Link Stud Bolts, Nuts and Spacers*	*6,815*	*7,361*
6	Link Pin Bushings	19,120	20,650
7	**Coat Link Bushings with Karon*	*6,564*	*7,090*
8	**Eye End Bolts, Shim Plate, Dowels & Nuts*	*117,289*	*126,673*
9	Lever Taper Keys and Screws	5,386	5,817
10	Inner Blade Shank Bushings and Dowels	29,004	31,325
11	Outer Blade shank Bushing	53,574	57,860
12	**Ship Existing Blade Shank Bushing*	*8,223*	*8,881*
13	**Coat Inner Blade Bushings with Karon*	*61,467*	*66,385*
14	**Coat Outer Blade Bushings with Karon*	*87,465*	*94,463*
15	Servomotor Piston Rod Bushing	9,255	9,996
16	Crosshead Bushing and Dowels	8,196	8,852
17	**Blade Servo operating Nuts*	*16,276*	*17,579*
18	Blade Packing Sleeves	44,345	47,893
19	Blade Servomotor Piston Rings	24,853	26,842
20	Blade Servomotor Piston Rod Rings	3,770	4,072
	Total Capitalized Items	357,871	386,508
	Total Expensed Items	205,827	222,297
	Grand Total	**$563,698**	**$608,805**

** Capitalized items*

F.2.3. Total Estimated Costs for Strategy A

The costs shown in Table F-3 are the anticipated general repair and contract prices. The contract price is based on a John Day unit 16-type repair on a BLH unit. The time to perform contract work from the Notice to Proceed until the unit is returned to service is about 18 months.

Table F-3. Per Unit Total Estimated Costs for Strategy A, Kaplan Repair by Regular Contract

Item No.	Description	Kaplan Repair Oct 2009 Cost ($)
1	Temporary Propeller Repair by Project Staff	171,000
2	Site Mobilization	300,000
3	Site Demobilization	100,000
4	Unit Disassembly	200,000
5	Unit Reassembly	300,000
6	Disassembly/Reassembly Runner	300,000
7	Clean and Polish Blade Trunnion/Blade Lever	15,000
8	Parts and Materials	40,000
9	RT/MT Blade Levers/Crosshead	10,000
10	Renew Hub Internal Components	610,000
	Subtotal Repair Cost	2,046,000
	Non-Contract Cost	405,200
	Contingencies	283,900
	Strategy A Total Cost	**$2,735,100**

F.3.0. Strategy B, Conversion to Fixed-blade Propeller

Strategy B involves fixing the blades permanently at 29 degrees by installing 3 pins though the blade flange into the runner hub effectively fixing the blades in one position (see Appendix A). This cost will be a combination of project costs to prepare the unit for permanent conversion to propeller operation and the contract costs to perform the drilling and pinning of each blade. The project costs for this work are identified in Table F-4. The project dewaters the unit, removes oil, installs the stop logs, installs the platform, and removes all these items and waters up the unit when the work is complete. The project will also help in the drilling and pinning of each blade to a certain extent. Specialized tools and fixtures are needed to bore the holes in the blade. There is a one-time cost for these tools of $40,000, which will remain Government property. The expected time to perform this work is within about 5 months after the failure of the unit (see Appendix G, Permanent Propeller by Contract).

Table F-4. Per Unit Total Estimated Costs for Strategy B to Permanently Pin Blades

Description	Permanent Repair Costs Oct 2009 ($)
Project Labor Cost	80,000
Contract Cost	100,000
Non-Contract Costs	50,000
Contingencies	15,000
Strategy B Total Cost	**$245,000***

*Does not include one-time tool cost of $40,000.

F.4.0. Strategy C, Full Kaplan Repair by IDIQ Contract

Strategy C is to assemble a task order scope of work after unit failure to award an IDIQ Contract for the repair. The unit is expected to be out of service for about 24 months, about 6 months to get the specification and task order together and the funding in place. It will take the contractor about 18 months to repair the turbine to full Kaplan function (see Appendix G, Kaplan Repair by IDIQ). Table F-5 shows the expected costs to perform this repair and assumes the turbine runner parts are available for the Contractor to use.

Table F-5. Per Unit Total Estimated Costs for Strategy C, Kaplan Repair by IDIQ Contract

Item No.	Description	Kaplan Repair Oct 2009 Cost ($)
1	Site Mobilization	300,000
2	Site Demobilization	100,000
3	Unit Disassembly	200,000
4	Unit Reassembly	300.000
5	Disassembly/Reassembly Runner	300,000
6	Clean and Polish Blade Trunnion/Blade Lever	15,000
7	Parts and Materials	40,000
8	RT/MT Blade Levers/Crosshead	10,000
9	Renew Hub Internal Components	610,000
	Subtotal Repair Cost	1,875,000
	Non-Contract Costs	371,000
	Contingencies	258,300
	Strategy C Total Cost	**$2,504,300**

F.5.0. Cost Summary for Strategies A, B and C

Table F-6 provides the estimated total costs for the three repair strategies based on October 1, 2009 cost levels.

Table F-6. Cost Summary for Strategies A, B and C

Description	Total Estimated Repair Oct 2009 Costs ($)
Strategy A - Repair to Kaplan by Contract	$2,735,100
Strategy B - Repair to Permanent Propeller	$245,000
Strategy C - Repair to Kaplan by IDIQ Contract	$2,504,300

F.6.0. Fish Passage Improvement Optional Work

If Strategy B is selected, the potential for additional fish passage improvements is possible by filling in the remaining runner blade gaps. Other fish passage mitigation measures may also considered; however, they are unknown and not included in the economic evaluation for this report. The cost in Table F-7 is not included in any estimate used in this report and is provided as a potential fish passage improvement for future consideration. The blade gaps to be filled would be the outside edge near the discharge ring area. The inside edge of the blade is between 0.5- and 0.75-inch from the runner hub and it is not necessary to fill in this gap (see Appendix A). The first unit to have the gaps filled would include a one-time cost ($25,000) to manufacture the patterns. Subsequent units will not incur this cost. It is estimated the improvement would add about 3 months to the schedule (see Appendix G, Strategy B).

Table F-7. Estimated Per Unit Added Cost to Fill Blade Gaps

Description	Permanent Repair Costs Oct 2009 ($)
Project Labor Cost	25,000
Contract Cost	150,000
Non-Contract Costs	50,000
Contingencies	15,000
Total Cost	**$240,000***

*Does not include one-time pattern cost of $25,000.

Appendix G
Construction Schedules

Appendix G
Construction Schedules

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G.1.0. Detailed Schedules

Figures G-1 to G-4 show detailed construction schedules for Strategies A, B, C, and temporary repair to propeller form the basis of costs, benefits, and timing expenditures for the economics presented in this report (see Appendices D and E). These schedules are estimates only for the purposes of this report and reflect assumptions reached by consensus of the Project Development Team (PDT).

G.2.0. Assumed Failures

The assumed failures used in the economic analysis for all the projects were randomly selected by the PDT and in no way are a prediction of actual failures. The estimated time of failure has been normalized to provide comparative information (20-year study period) for meaningful economic analysis. The assumed failures used for Strategies A, B and C are shown below.

John Day

For John Day Units 1-16, two series of failures were evaluated with five and eight failures over the 20-year study period.

<u>Five units fail (Figures G-5 and G-6)</u>:

- 1st-year Failure
- 3rd-year Failure
- 5th-year Failure
- 7th-year Failure
- 9th-year Failure

<u>Eight units fail (Figures G-7 and G-8)</u>:

- 1st-year Failure
- 3rd-year Failure
- 5th-year Failure
- 7th-year Failure
- 9th-year Failure
- 11th-year Failure
- 13th-year Failure
- 15th-year Failure

Lower Monumental

For Lower Monumental Units 1-3, only one failure was assumed to occur the 1st year in the 20 year study period (Figure G-9).

Little Goose

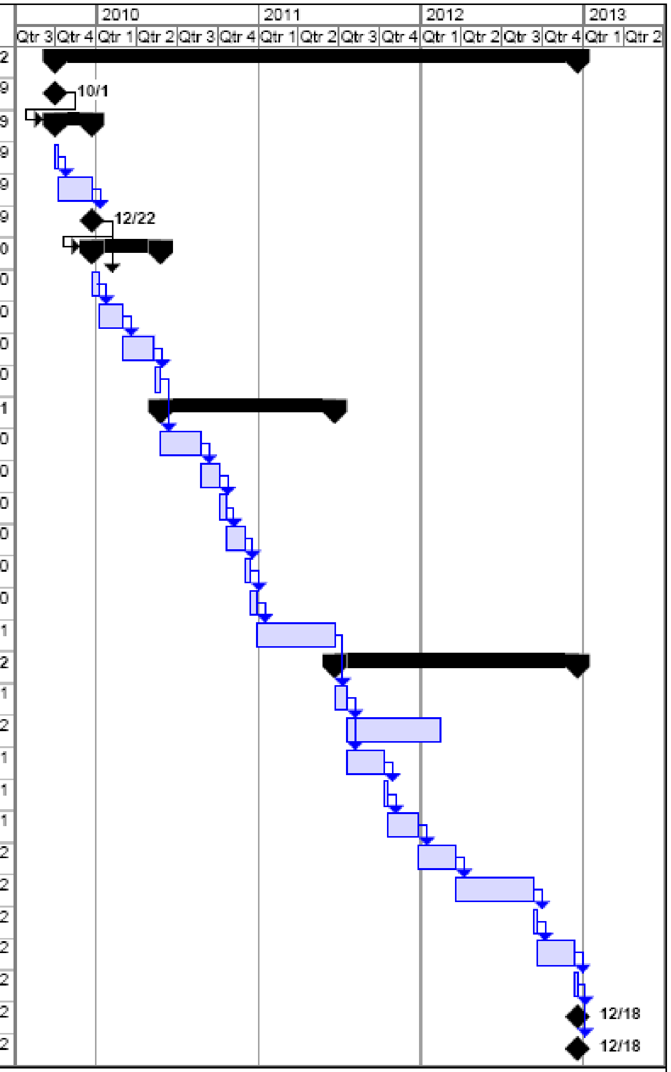
For Little Goose Units 1-3, only one failure was assumed to occur the 1st year in the 20 year study period (Figure G-9).

Lower Granite

For Lower Granite Units 1-3, only one failure was assumed to occur the 1st year in the 20 year study period (Figure G-9).

Figure G-1. Detailed Schedule for Strategy A, Kaplan Repair by Contract

ID		Task Name	Duration	Start	Finish
1		**Kaplan Repair by Contract (Strategy A: 39 Months)**	**839 days**	**Thu 10/1/09**	**Tue 12/18/12**
2		Unit Failure (OOS)	0 days	Thu 10/1/09	Thu 10/1/09
3		**Failure Invest. - Broken Blade Linkage**	**59 days**	**Thu 10/1/09**	**Tue 12/22/09**
4		Dewater Unit	4 days	Thu 10/1/09	Tue 10/6/09
5		Perform Temporary Blade Weld	55 days	Wed 10/7/09	Tue 12/22/09
6		POL	0 days	Tue 12/22/09	Tue 12/22/09
7		**Sub Agreement**	**110 days**	**Wed 12/23/09**	**Tue 5/25/10**
8		Preparation of Decision Document	10 days	Wed 12/23/09	Tue 1/5/10
9		Capital Work Group Presentation	40 days	Wed 1/6/10	Tue 3/2/10
10		Prepare & Sign Subagreement	50 days	Wed 3/3/10	Tue 5/11/10
11		Transfer Funds	10 days	Wed 5/12/10	Tue 5/25/10
12		**Contract**	**280 days**	**Wed 5/26/10**	**Tue 6/21/11**
13		Prepare Specification	65 days	Wed 5/26/10	Tue 8/24/10
14		ITR & Review	30 days	Wed 8/25/10	Tue 10/5/10
15		Prepare P & S for Advertise	10 days	Wed 10/6/10	Tue 10/19/10
16		Advertise	30 days	Wed 10/20/10	Tue 11/30/10
17		Evaluate Experience and Bids	10 days	Wed 12/1/10	Tue 12/14/10
18		Award Contract & NTP	10 days	Wed 12/15/10	Tue 12/28/10
19		Contingency	125 days	Wed 12/29/10	Tue 6/21/11
20		**Repair to Kaplan (18 months)**	**390 days**	**Wed 6/22/11**	**Tue 12/18/12**
21		Contractor Mobilizes	20 days	Wed 6/22/11	Tue 7/19/11
22		Fabrication of Linkage Parts	150 days	Wed 7/20/11	Tue 2/14/12
23		Disassemble Gen Unit to Runner	60 days	Wed 7/20/11	Tue 10/11/11
24		Remove Runner from Water Passage	5 days	Wed 10/12/11	Tue 10/18/11
25		Disassemble Runner in prep for Repair	50 days	Wed 10/19/11	Tue 12/27/11
26		Reassemble Runner with New Parts	60 days	Wed 12/28/11	Tue 3/20/12
27		Contingency Time	125 days	Wed 3/21/12	Tue 9/11/12
28		Place Runner in Water Passage	5 days	Wed 9/12/12	Tue 9/18/12
29		Reassemble Generating Unit	60 days	Wed 9/19/12	Tue 12/11/12
30		Commission Unit	5 days	Wed 12/12/12	Tue 12/18/12
31		POL	0 days	Tue 12/18/12	Tue 12/18/12
32		Cost Strategy A = $2,735k Appendix F Table F3	0 days	Tue 12/18/12	Tue 12/18/12

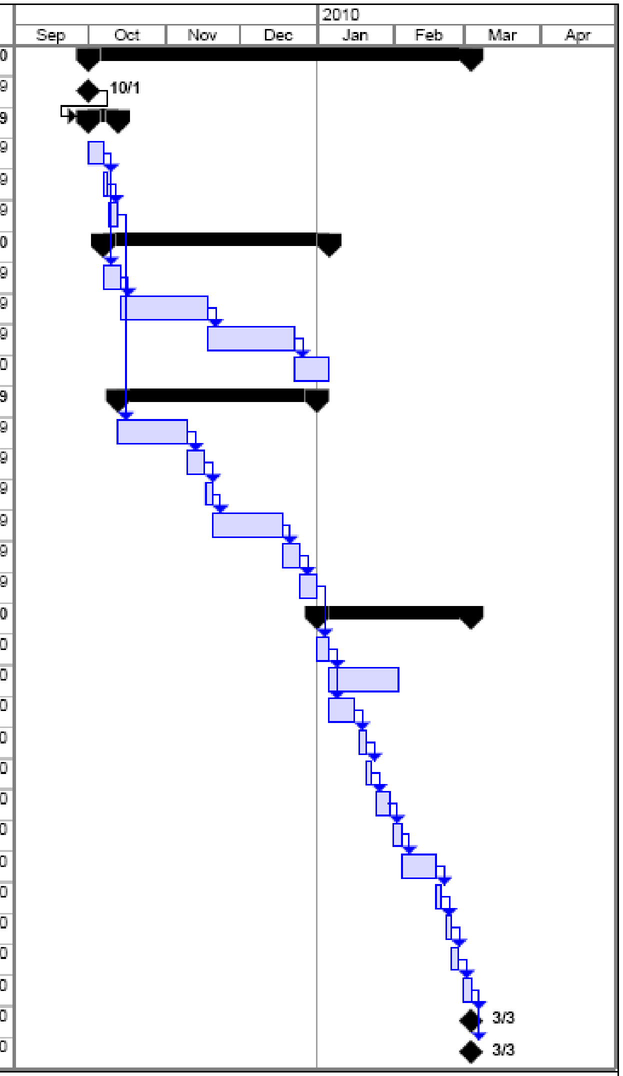


Project: Strategy A
Date: Mon 3/2/09

Task, Split, Progress, Milestone, Summary, Project Summary, External Tasks, External Milestone, Deadline

Figure G-2. Detailed Schedule for Strategy B, Permanent Repair to Propeller by Contract

ID	Task Name	Duration	Start	Finish
1	**Permanent Propeller by Contract (Strategy B: 5 Months)**	**110 days**	**Thu 10/1/09**	**Wed 3/3/10**
2	Unit Failure (OOS)	0 days	Thu 10/1/09	Thu 10/1/09
3	**Failure Invest. - Broken Blade Linkage**	**8 days**	**Thu 10/1/09**	**Mon 10/12/09**
4	Dewater Unit	4 days	Thu 10/1/09	Tue 10/6/09
5	Install Platform	2 days	Wed 10/7/09	Thu 10/8/09
6	Remove Hub Oil	2 days	Fri 10/9/09	Mon 10/12/09
7	**Sub Agreement**	**65 days**	**Wed 10/7/09**	**Tue 1/5/10**
8	Preparation of Decision Document	5 days	Wed 10/7/09	Tue 10/13/09
9	Capital Work Group Presentation	25 days	Wed 10/14/09	Tue 11/17/09
10	Prepare and Sign Sub Agreement	25 days	Wed 11/18/09	Tue 12/22/09
11	Transfer Funds	10 days	Wed 12/23/09	Tue 1/5/10
12	**Contract**	**58 days**	**Tue 10/13/09**	**Thu 12/31/09**
13	Prepare Specification	20 days	Tue 10/13/09	Mon 11/9/09
14	ITR & Review	5 days	Tue 11/10/09	Mon 11/16/09
15	Revise Specification	3 days	Tue 11/17/09	Thu 11/19/09
16	Advertize	20 days	Fri 11/20/09	Thu 12/17/09
17	Evaluate Bids	5 days	Fri 12/18/09	Thu 12/24/09
18	Award Contract & NTP	5 days	Fri 12/25/09	Thu 12/31/09
19	**Repair to Permanent Propeller**	**44 days**	**Fri 1/1/10**	**Wed 3/3/10**
20	Contractor Mobilizes	3 days	Fri 1/1/10	Tue 1/5/10
21	Procure Boring Tool	20 days	Wed 1/6/10	Tue 2/2/10
22	Lower Cone and Inspect Blade Linkage	8 days	Wed 1/6/10	Fri 1/15/10
23	Unstick Failed Blade	3 days	Mon 1/18/10	Wed 1/20/10
24	Remove broken Parts	2 days	Thu 1/21/10	Fri 1/22/10
25	Raise Cone Tighten Fasteners, Install Cover Plates	5 days	Mon 1/25/10	Fri 1/29/10
26	Set Blade Angle & Fixture	3 days	Mon 2/1/10	Wed 2/3/10
27	Bore Holes & Install Pins	10 days	Thu 2/4/10	Wed 2/17/10
28	Replace Oil in Hub	2 days	Thu 2/18/10	Fri 2/19/10
29	Remove Platform	2 days	Mon 2/22/10	Tue 2/23/10
30	Water up Unit	3 days	Wed 2/24/10	Fri 2/26/10
31	Commission Unit	3 days	Mon 3/1/10	Wed 3/3/10
32	**POL**	**0 days**	**Wed 3/3/10**	**Wed 3/3/10**
33	**Cost Strategy B = $245k Appendix F Table F4**	**0 days**	**Wed 3/3/10**	**Wed 3/3/10**

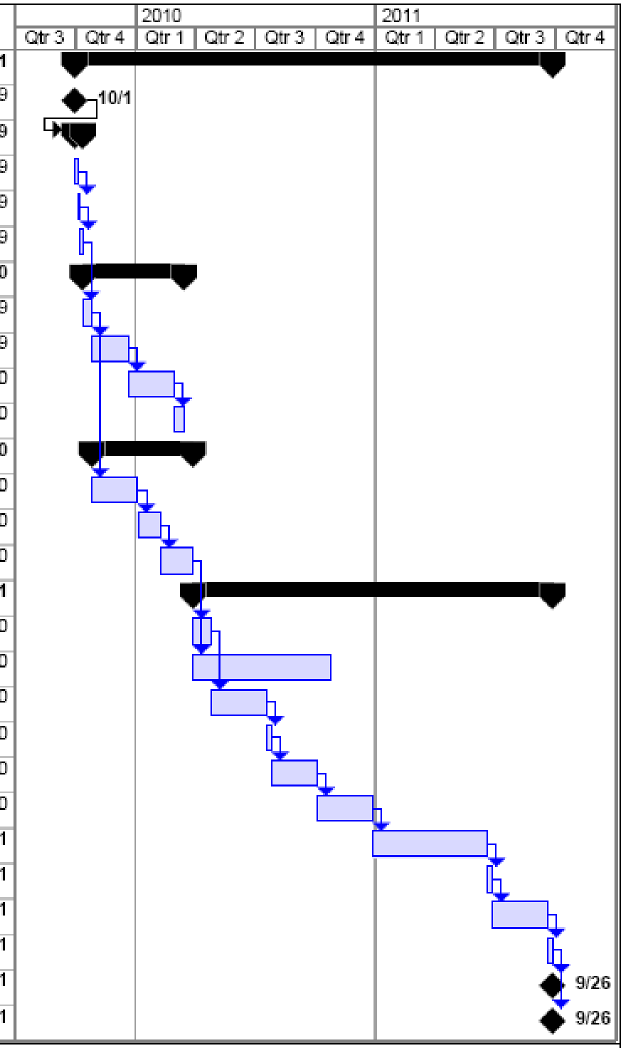


Project: Strategy B
Date: Mon 3/2/09

Task		Milestone		External Tasks	
Split		Summary		External Milestone	
Progress		Project Summary		Deadline	

Figure G-3. Detailed Schedule for Strategy C, Kaplan Repair by IDIQ Contract

ID	Task Name	Duration	Start	Finish
1	**Kaplan Repair by IDIQ (Strategy C: 24 Months)**	**518 days**	**Thu 10/1/09**	**Mon 9/26/11**
2	Unit Failure (OOS)	0 days	Thu 10/1/09	Thu 10/1/09
3	**Failure Invest. - Broken Blade Linkage**	**8 days**	**Thu 10/1/09**	**Mon 10/12/09**
4	Dewater Unit	4 days	Thu 10/1/09	Tue 10/6/09
5	Install Platform	2 days	Wed 10/7/09	Thu 10/8/09
6	Remove Hub Oil	2 days	Fri 10/9/09	Mon 10/12/09
7	**Sub Ageement**	**110 days**	**Tue 10/13/09**	**Mon 3/15/10**
8	Preparation of Decision Document	10 days	Tue 10/13/09	Mon 10/26/09
9	Capital Work Group Presentation	40 days	Tue 10/27/09	Mon 12/21/09
10	Prepare & Sign Subagreement	50 days	Tue 12/22/09	Mon 3/1/10
11	Transfer Funds	10 days	Tue 3/2/10	Mon 3/15/10
12	**IDIQ Contract**	**110 days**	**Tue 10/27/09**	**Mon 3/29/10**
13	Prepare Task Order Scope of Work	50 days	Tue 10/27/09	Mon 1/4/10
14	ITR & Review	25 days	Tue 1/5/10	Mon 2/8/10
15	NTP	35 days	Tue 2/9/10	Mon 3/29/10
16	**Repair to Kaplan (18 Months)**	**390 days**	**Tue 3/30/10**	**Mon 9/26/11**
17	Contractor Mobilizes	20 days	Tue 3/30/10	Mon 4/26/10
18	Fabrication of Linkage Parts	150 days	Tue 3/30/10	Mon 10/25/10
19	Disassemble Gen Unit to Runner	60 days	Tue 4/27/10	Mon 7/19/10
20	Remove Runner from Water Passage	5 days	Tue 7/20/10	Mon 7/26/10
21	Disassemble Runner in prep for Repair	50 days	Tue 7/27/10	Mon 10/4/10
22	Reassemble Runner with New Parts	60 days	Tue 10/5/10	Mon 12/27/10
23	Contingency Time	125 days	Tue 12/28/10	Mon 6/20/11
24	Place Runner in water Passage	5 days	Tue 6/21/11	Mon 6/27/11
25	Reassemble Generating Unit	60 days	Tue 6/28/11	Mon 9/19/11
26	Commission Unit	5 days	Tue 9/20/11	Mon 9/26/11
27	**POL**	0 days	Mon 9/26/11	Mon 9/26/11
28	**Cost Strategy C = $2,500k Appen F Table F5**	0 days	Mon 9/26/11	Mon 9/26/11

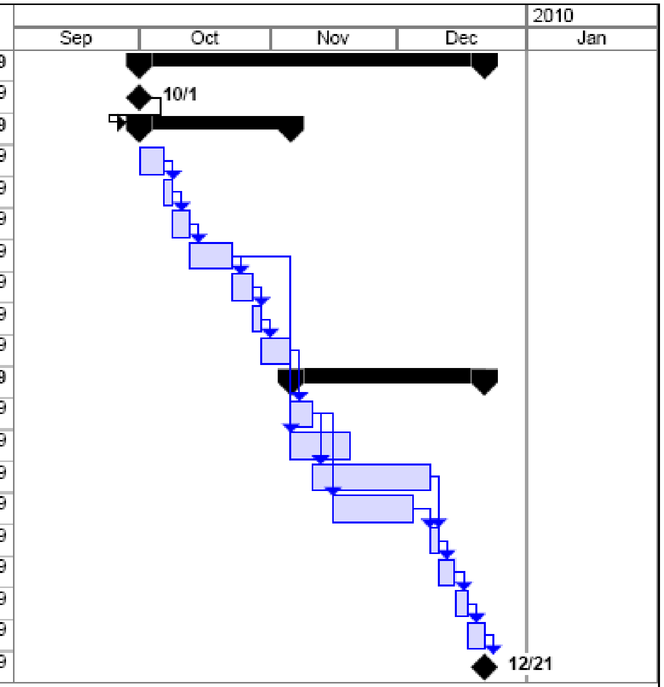


Project: Strategy C
Date: Mon 3/2/09

Task		Milestone		External Tasks	
Split		Summary		External Milestone	
Progress		Project Summary		Deadline	

Figure G-4. Detailed Schedule for a Temporary Repair to Propeller by Project Staff

ID	Task Name	Duration	Start	Finish
1	**Temp. Propeller by Proj. Forces**	**58 days**	**Thu 10/1/09**	**Mon 12/21/09**
2	Unit Failure (OOS)	0 days	Thu 10/1/09	Thu 10/1/09
3	**Failure Invest. - Broken Blade Linkage**	**26 days**	**Thu 10/1/09**	**Thu 11/5/09**
4	Dewater Unit	4 days	Thu 10/1/09	Tue 10/6/09
5	Install Platform	2 days	Wed 10/7/09	Thu 10/8/09
6	Remove Hub Oil	2 days	Fri 10/9/09	Mon 10/12/09
7	Lower Cone and Inspect Blade Linkage	8 days	Tue 10/13/09	Thu 10/22/09
8	Unstick Failed Blade	3 days	Fri 10/23/09	Tue 10/27/09
9	Remove broken Parts	2 days	Wed 10/28/09	Thu 10/29/09
10	Replace Cone	5 days	Fri 10/30/09	Thu 11/5/09
11	**Repair to Temporary Propeller**	**32 days**	**Fri 11/6/09**	**Mon 12/21/09**
12	Set Blade Angle	3 days	Fri 11/6/09	Tue 11/10/09
13	Machine Blade Blocks	10 days	Fri 11/6/09	Thu 11/19/09
14	Weld Blocks to Hub	20 days	Wed 11/11/09	Tue 12/8/09
15	Cavitation Resistant Repair around Blocks	15 days	Mon 11/16/09	Fri 12/4/09
16	Repalce Oil in Hub	2 days	Wed 12/9/09	Thu 12/10/09
17	Remove Platform	2 days	Fri 12/11/09	Mon 12/14/09
18	Water up Unit	3 days	Tue 12/15/09	Thu 12/17/09
19	Operational Checks	2 days	Fri 12/18/09	Mon 12/21/09
20	POL	0 days	Mon 12/21/09	Mon 12/21/09



Project: Temporay repair
Date: Mon 3/2/09

Task	Milestone	External Tasks
Split	Summary	External Milestone
Progress	Project Summary	Deadline

Figure G-5. John Day Kaplan Blade Adjustment Failure Scenarios, Five Failures, Base Case and Strategy A

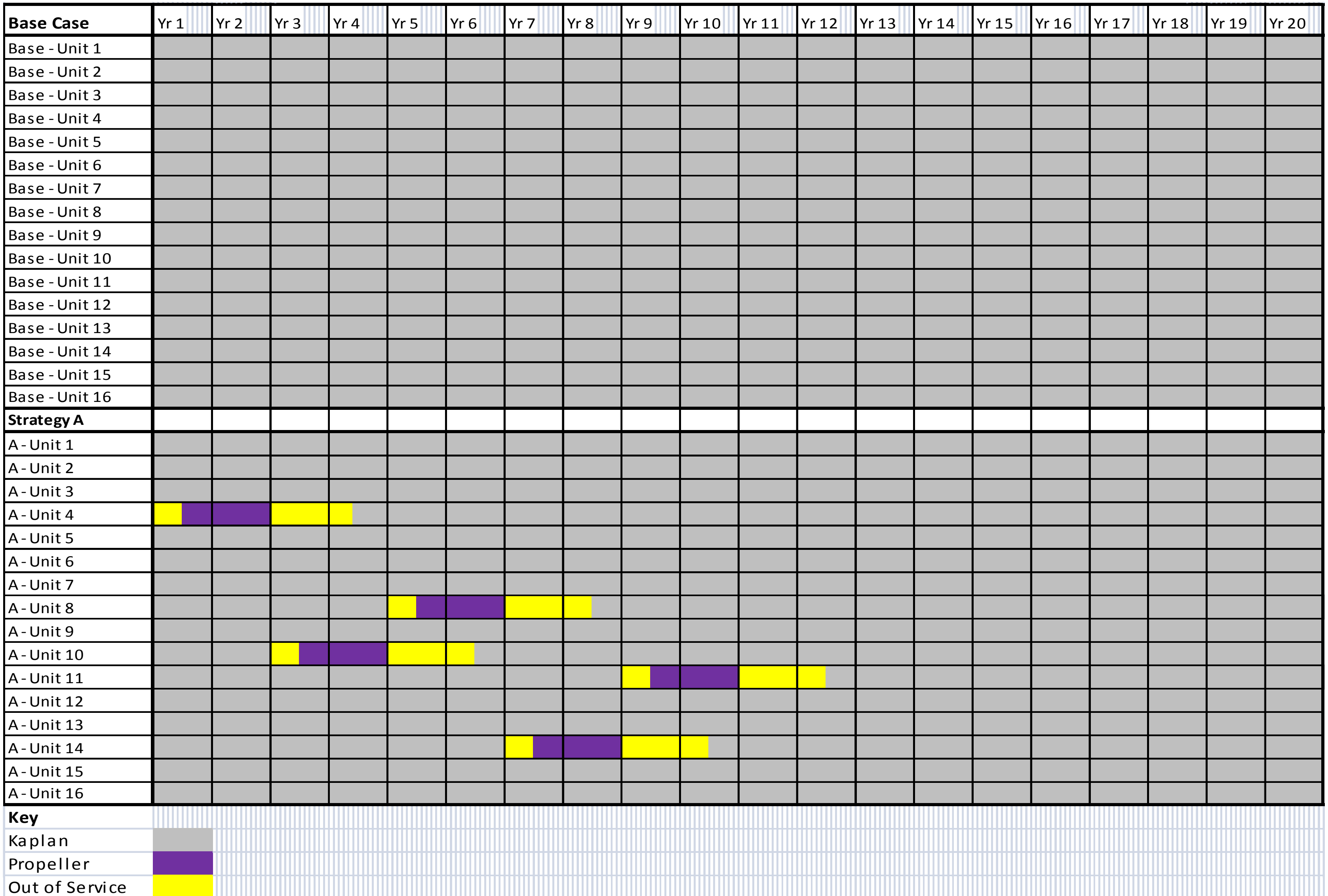


Figure G-6. John Day Kaplan Blade Adjustment Failure Scenarios, Five Failures, Strategy B and Strategy C

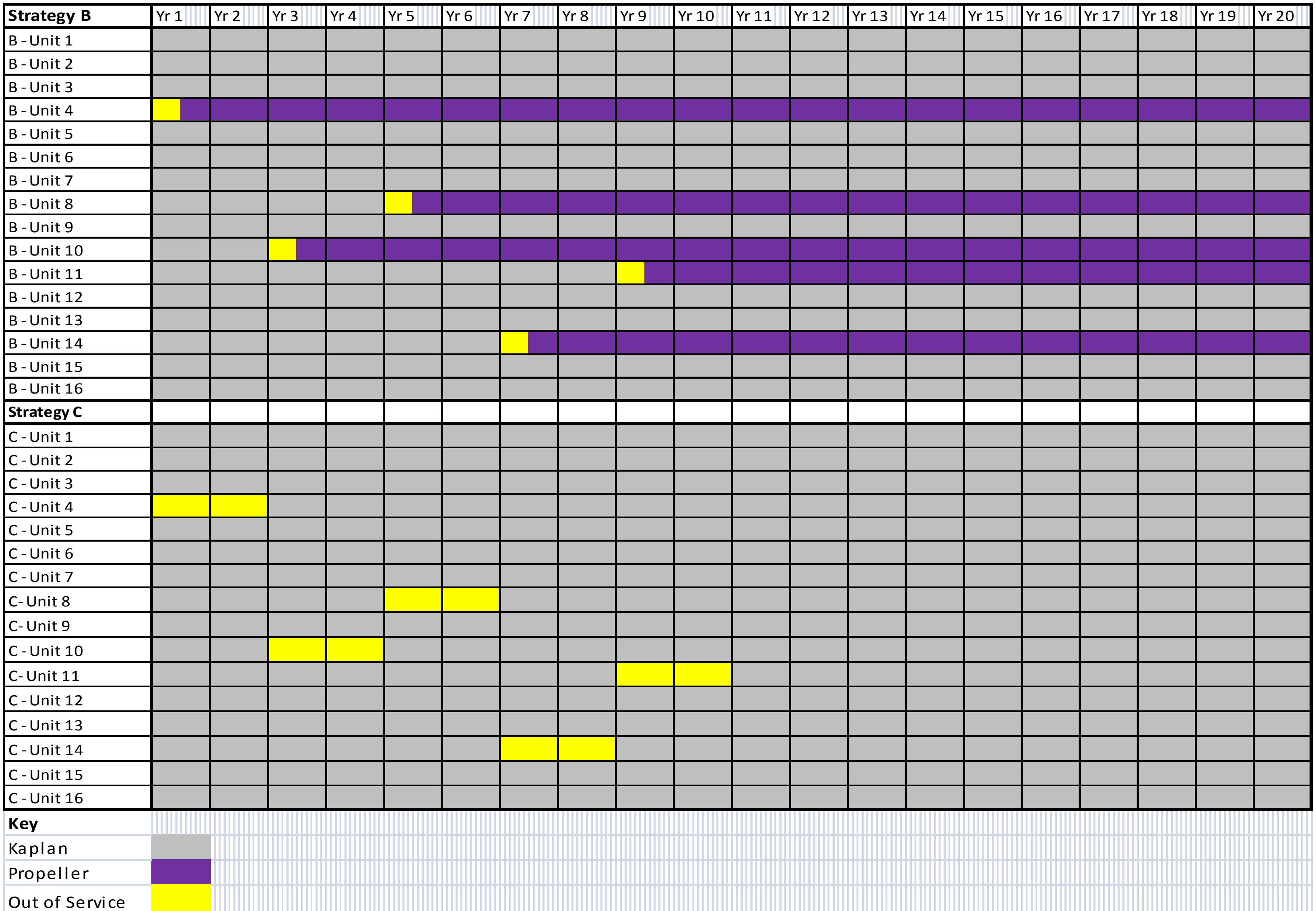


Figure G-7. John Day Kaplan Blade Adjustment Failure Scenarios, Eight Failures, Base Case and Strategy A

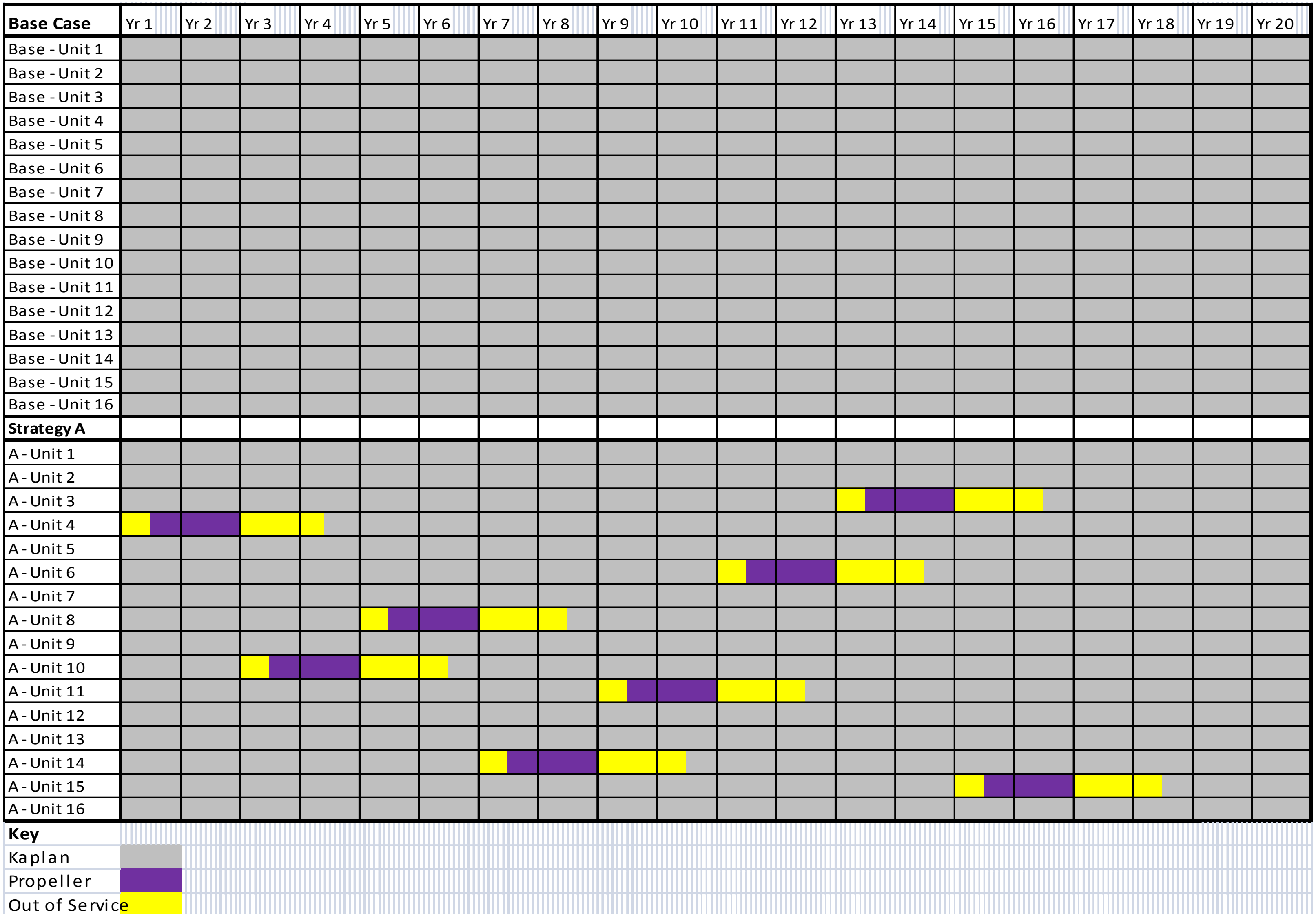


Figure G-8. John Day Kaplan Blade Adjustment Failure Scenarios, Eight Failures, Strategy B and Strategy C

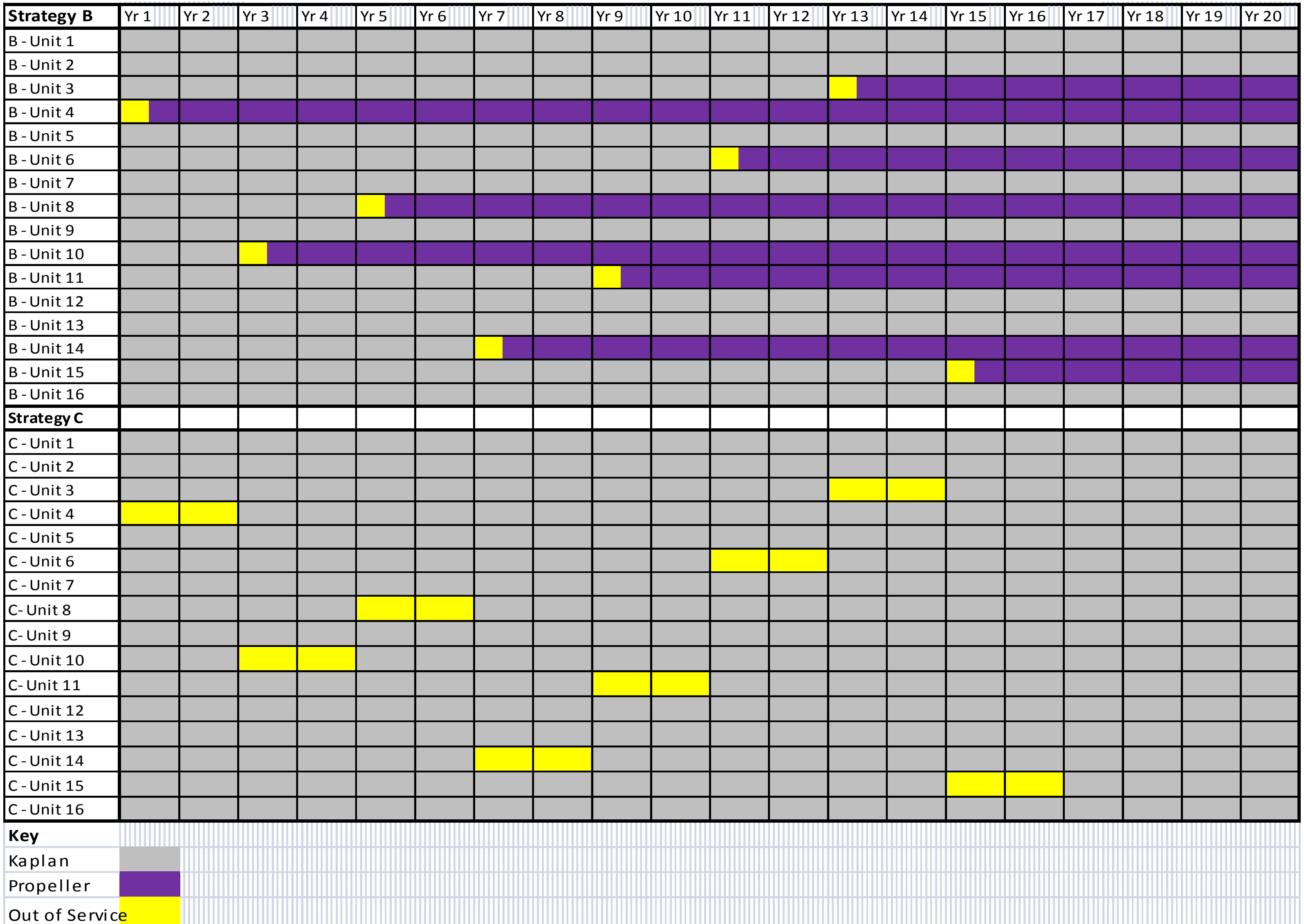
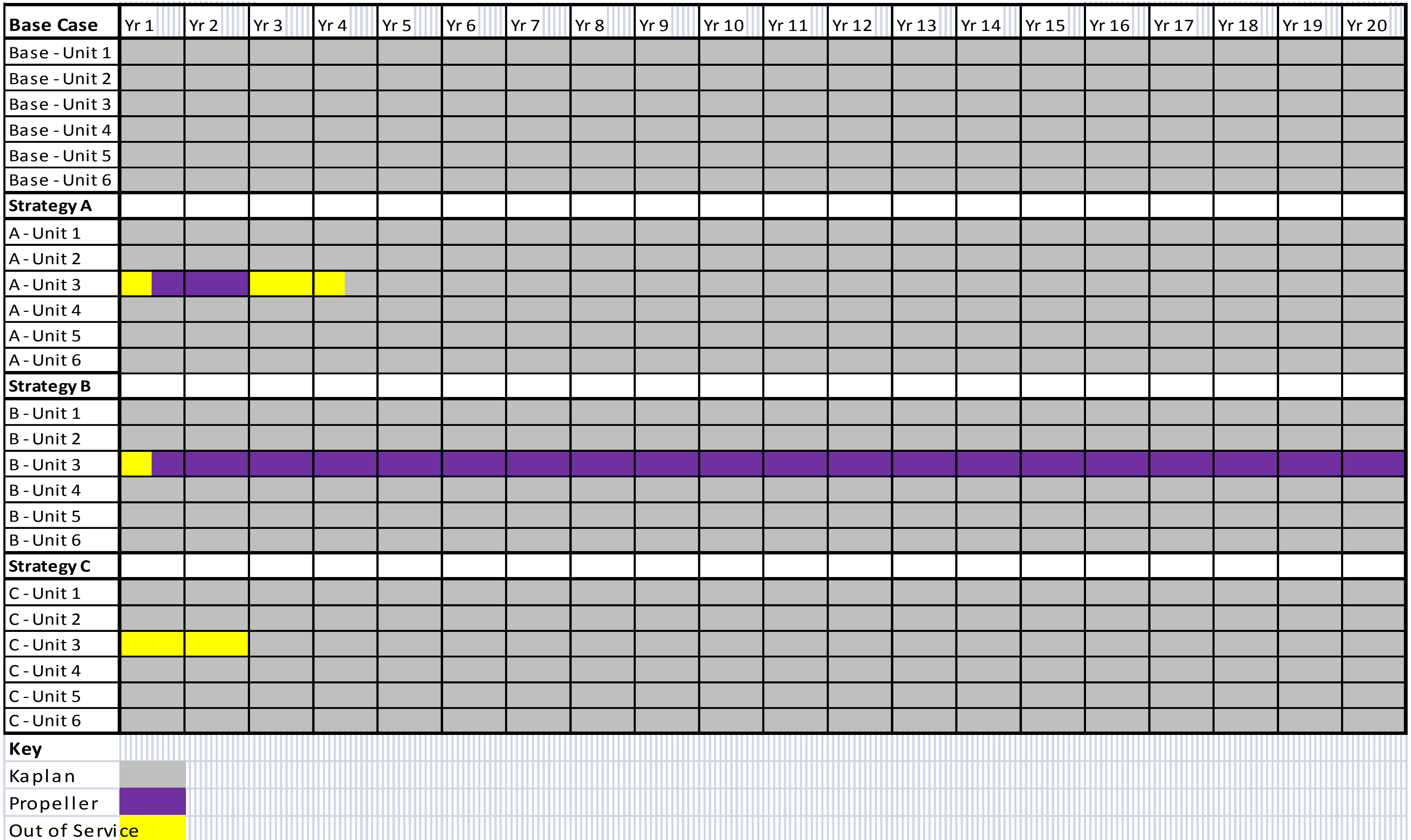


Figure G-9. Lower Snake River Kaplan Blade Adjustment Failure Scenarios



Appendix H
Generation and Transmission System Considerations

Appendix H
Generation and Transmission System Considerations

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H.1.0. Background

The Bonneville Power Administration (BPA) is a partner in the Federal Columbia River Power System (FCRPS) with the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation. The BPA markets the power generated by FCRPS hydropower plants. The BPA also direct funds all power related costs for the Corps and the Bureau of Reclamation. The BPA's vision is to advance a Northwest power system that is a national leader in providing:

- High reliability;
- Low rates consistent with sound business principles;
- Responsible environmental stewardship; and
- Accountability to the region.

As noted in BPA's vision statement, environmental stewardship is a key factor in business considerations. Fish passage at all the projects is of utmost importance. At each project under consideration in this study, fish priority units have been identified that provide flow near the fish ladder to attract upstream migrants. For these units, fish passage considerations take precedence over power considerations and BPA recognizes the need to retain the Kaplan capability of the units to provide fish attraction water, while maintaining a wide operating range to effectively meet minimum generation requirements.

The BPA's 2009 System Asset Plan categorizes the FCRPS hydro plants (Table H-1) based on criticality of assets, ranking projects into four strategic classes depending on the role they serve in the hydro system, and three levels of relative cost of unavailability (RCU). Of the projects under consideration in this report, John Day ranks in the highest strategic class and its RCU is categorized as extreme. Lower Granite, Little Goose, and Lower Monumental rank in the second highest strategic class and their RCU is categorized as major.

H.2.0. System Considerations

All projects considered in this study provide significant power benefits to the FCRPS. There are two key factors to consider when reviewing system impacts: capacity and load following capability. Maintaining capacity is important to ensure a reliable power system as load growth occurs in the FCRPS. Load following capability is increasingly important as wind generation increases dramatically in the region and hydro plants are being called upon on an increasing basis to maintain system stability and provide generation flexibility.

In the late 1960s and early to mid 1970s, identical Baldwin-Lima-Hamilton (BLH) turbines were installed in all 16 main units at John Day, and in main units 1-3 at Lower Monumental, Little Goose, and Lower Granite (9 units total). The blade linkage pins used on these units have proven susceptible to failure, leaving the unit inoperable. Repair choices are to repair the unit to full Kaplan capability, or to fix the blades in place.

Table H-1. FCRPS Hydro Plant Classification

Relative Cost of Unavailability	Local Support	Area Support	Headwater/ Lower Snake	Main Stem Columbia
Severe >$40M/yr				CHJ GCL MCN
Extreme $10M-$20M/yr			DWR	**JDA**
Major <$10M/yr	AND, BCD BDD, MIN ROZ, CDR GSP	BCL, DEX LOS, DET GPR, LOP HCR, CGR FOS, ALF, PAL	LIB, HGH IHR**, LGS** **LWG, LMN**	BON TDA

Key:

Local Support: Plants that provide services primarily to local areas. These plants include Anderson Ranch (AND), Black Canyon (BCD), Boise Diversion (BDD), Minidoka (MIN), Roza (ROZ), Chandler (CDR), and Green Springs (GSP).

Area Support: Plants with a sub-regional impact that provide key power and non-power benefits to specific areas of the Pacific Northwest. These plants include Big Cliff (BCL), Dexter (DEX), Lost Creek (LOS), Detroit (DET), Green Peter (GPR), Lookout Point (LOP), Hills Creek (HCR), Cougar (CGR), Foster (FOS), Albeni Falls (ALF), and Pallisades (PAL).

Headwater/Lower Snake: Plants that provide significant power and non-power benefits to the region. These plants include Dworshak (DWR), Libby (LIB), Hungry Horse (HGH), Ice Harbor (IHR), Little Goose (LGS), Lower Granite (LWG), and Lower Monumental (LMN).

Main Stem Columbia: Plants that provide the majority of power, ancillary services, and non-power benefits to the Pacific Northwest. These plants include Chief Joseph (CHJ), Grand Coulee (GCL), McNary (MCN), John Day (JDA), Bonneville (BON), and The Dalles (TDA).

Source: BPA 2009 System Asset Plan.

Fixing blades limits the operating range of a unit and also the peak power of the unit as compared to the same unit with full Kaplan capabilities. While the potential limitations at these plants resulting from fixed blade repairs represent a fairly small fraction of the capacity and load following capability of the system as a whole, there are significant considerations relating to system operation that should be taken into account. The impact of blade linkage failures was discussed among a group of BPA personnel representing schedulers, planning, operations, and federal hydro projects. The BPA group generally has concerns about reductions in unit capacity and reductions in operating range, which impacts load following capability that would be introduced by fixed blade repair scenarios.

H.2.1. John Day

John Day is unique among the projects under consideration in this report because of its location at the head of the north-south transmission intertie and because it has four units that provide condensing capability. The BPA federal hydro group determined that units 1 and 2 should remain Kaplan units due their status as fish priority units. In the event unit 5 fails, one unit in the group of units 3 through 8 should be converted to replace unit 5 for station power (see Appendix K for more information). Therefore, the worst-case failure scenario at John Day could have as many as twelve fixed-blade units and four Kaplan units (units 1, 2, 16 and a station service unit). However, it seems reasonable that after eight units are converted to fixed-blade units, that a strategy change to repair before failure would occur. In addition, it was determined by field testing that the four condensing units can continue to provide this generation stability feature, if repaired to fixed-blade turbines (see Appendix I).

H.2.2. Lower Monumental, Little Goose, and Lower Granite

The BPA thought that only one unit at these projects should be converted to a permanent fixed blade machine, unit 3. There was also discussion that these projects are all run-of-the-river, and that changing the operating characteristics of one unit (i.e. converting it to a fixed blade unit) not only affects the power generation and load following capability of that project, but may also impact projects downstream. The project-to-project operational interactions should be included as a factor for consideration when determining if a unit will be repaired to full Kaplan capability or repaired to a fixed-blade status.

H.2.3. Transmission

The implications of blade linkage failures were discussed with BPA transmission personnel and their concerns are focused on the impact of changes to their system stability studies that fixed blade units would introduce. Their recommendation is that they work with the projects once a turbine has been converted to a fixed blade unit to perform governor response model validation tests so that they can update their power flow and transient stability models.

H.3.0. Summary

Due to concerns about loss of capacity and ability to load follow, the BPA recommends that a maximum of eight units at John Day and one BLH unit at each of Lower Monumental, Little Goose, and Lower Granite be considered for permanent conversion to fixed-blade operation due to blade linkage failures. Other priorities, such as fish priority status of units, will likely determine whether a unit is repaired to full Kaplan capability if blade linkage failure occurs. There may be justification to inspect units and repair prior to failure due to the operating requirements of the plant, the high relative cost of unavailability, and the projects' strategic importance to the FCRPS.

Appendix I
Pertinent Documentation

(see Volume II)

Appendix J
Modify Before Failure

Appendix J
Modify Before Failure

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J.1.0. Kaplan Turbine Inspections and Repair Procedures

A graphical depiction of the "repair before failure" option is shown in Figure J-1. In this option, the fate of the 22 remaining BLH-type runners on the Lower Snake and Columbia rivers will be addressed in a planned mode. The Corps' Districts can prepare a contract to have a contractor perform the inspections of the remaining 22 units. For each inspection, the project will dewater the unit, remove the hub oil from the hub, and install the draft tube platform as the contractor is moving through the powerhouse. One powerhouse will be inspected at a time but the order of unit inspection within the powerhouse will be at the discretion of the project personnel. The existing John Day draft tube platform will not allow the lowering of the runner cone; however, the platforms for the three Lower Snake projects can perform this operation and have been used in the past for this purpose. The Walla Walla District is currently in the process of procuring a spare draft tube platform for Lower Granite Dam. The plans and specifications are currently being put together by the Walla Walla District. A platform for the John Day project can be obtained by either sharing the costs for the plans and specifications that are currently being put together and having a second platform fabricated or using the documents to procure a John Day platform independently. The estimated cost for a new platform is $80,000.

As depicted in Figure J-1, two separate contracts are suggested to accomplish the repair depending on the work involved. The first contract will handle the inspection of each of the remaining 23 runners. All defective units will be converted to temporary or permanent fixed-blade propeller runner. Those that are to remain Kaplan type will be rehabilitated at a later date by the second contract. The second contract will address unstacking and disassembling the unit, and disassembly and renewal of the runner hub internal components. The repair will be similar to the repair used for John Day unit 16.

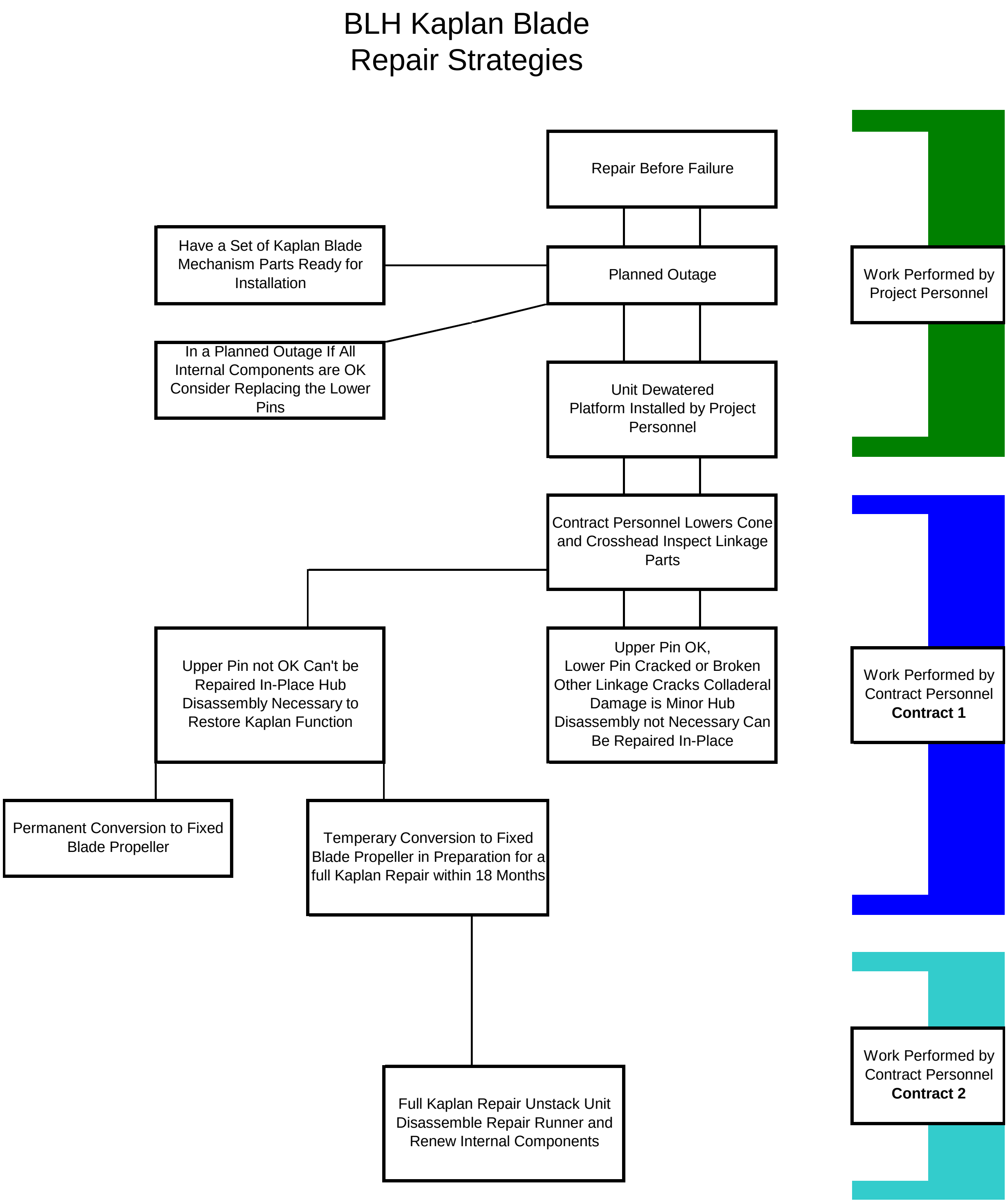
J.1.1. First Contract

The inspection will entail the contractor performing the following duties with the oil removed from the unit and the platform installed:

- Lower the runner cone on all-thread.
- Non-destructive testing (NDT) inspect the blade linkage to include:
  - Ultrasonic testing (UT) the end of each pin from both sides.
  - Dye penetrant testing (PT) the link plate around the two bored holes. Remove the six eye end nuts one at a time, jacking each blade flat so the eye end shank is exposed and PT the radius of each eye end at the change in cross section.
  - Install new superbolt[6] nuts on the eye ends and tighten nuts to the preload supplied by the Government.
  - Raise and reattach the cone and cover plates

[6] "Superbolt" is the trade name of a special type of fastener which permits very high pre-loads by using numerous smaller bolts around the periphery that are individually tightened without using special tools.

Figure J-1. Graphical Depiction of "Repair Before Failure" Option



J.1.1.1. <u>First Contract Repair Cases</u>

1. If the upper pin or any of the other linkage components except the lower pins are defective (i.e., fatigue cracks are discovered by UT or PT), the contractor will end all NDT efforts and raise and reattach the runner cone. The contractor will then set the runner blades at the angle as determined by the Government and weld blocks or use another method to fix the blades at the appropriate angle either permanently or temporarily as directed by the Government.
2. If the linkage parts show no signs of fatigue cracking, the contractor will replace the set of lower pins, and raise and reattach the runner cone at the direction of the Government.

J.1.2. Second Contract Return to Kaplan Service

This contract will be on a unit-by-unit basis for returning a unit to Kaplan service. If the results of the first contract show that the linkage is defective and a temporary fixed-blade repair is made, then the unit should operate in this mode for no more than 2 years. This timeframe will give the Corps' District time to determine a funding source and assemble a contract to rehabilitate the unit back to Kaplan service.

J.1.3. Schedule and Cost of Unit Inspections and Repairs

For the sake of estimating a cost and schedule for the repair before failure strategy, it can be assumed that the work is awarded by an IDIQ contracting process and that the contract would stipulate that the units would be investigated consecutively (i.e., after each unit is investigated and parts replaced the next unit would be taken out of service and investigated and repaired etc). The work could also be performed on a unit-by-unit basis, but it would substantially increase the time it takes to get through all the units. Tables J-1 and J-2 show both scenarios: (1) the cost to perform the inspection on just one unit, and (2) the cost to inspect for all 22 remaining units.

The process will proceed as described in Section J.1.1. The project will dewater the unit, place the platform and remove the turbine hub oil from the unit. This will take about 2 weeks. The contractor will lower the cone, inspect the parts, replace the targeted parts, and raise and attach the hub cone. This will take about 6 weeks. Then the project will remove the platform, replace the oil in the hub and water up the unit taking about 2 weeks until the unit is back up and operating. The total out of service time is about 3 months, with a 2-week contingency added for unforeseen events.

Table J-1. Inspection Cost for One Unit

Description (3 months out of service)	Permanent Repair Costs (Oct 2009)
Project Labor Cost	$50,000
Contract Cost	$100,000
BLH Spare Parts Cost	$80,000
Non-Contract Costs	$50,000
Contingencies	$20,000
Total Cost	**$300,000**

Table J-2. Inspection Cost for 22 Units

Description (3 months out of service per unit)	**Permanent Repair Costs (Oct 2009)**
Project Labor Cost	$1,100,000
Contract Cost	$2,090,000
BLH Spare Parts Cost	$1,760,000
Engineering &Design Costs	$100,000
Non-Contract Costs	$660,000
Contingencies	$200,000
Total Cost	**$5,910,000**

J.2.0. Prior Research, Testing, Reports, and Demonstrations to Extend Life

J.2.1. John Day Turbine Repair Report (1983)

Subsequent to the original failures in the Baldwin-Lima-Hamilton (BLH) turbines at the John Day powerhouse, a many investigations and tests were performed over a period of many years to determine not only the cause of the failures but also to determine how to extend the life of the hub internal components. A two-volume Corps' report titled, *Study for Turbine Repair, Powerhouse Major Rehabilitation Program, John Day Powerhouse, Oregon and Washington* (September 1983) documents the original failure history, actions taken, and research and testing performed during the period from 1970 to 1983. The purpose of the report was to justify funding for a major rehabilitation of the John Day turbines that would essentially pay for repairs for the turbines which had not yet failed. Although approved by Corps' headquarters, no rehab program money was provided. Repairs to the remaining un-failed turbines were performed using operations and maintenance funds.

One of the outcomes of this work was that reducing the friction factor in the bushings is the most effective means of prolonging service life. This is because approximately 90% of the force developed by the blade servomotor is needed to overcome friction. Only a small part of the servo effort is needed to overcome hydraulic loads produced by water flowing over the blades. Also discovered was that the blades do not move in a smooth manner – they move independently in a series of small jerky motions, even for relatively small blade angle changes. Numerous different lubricating oils were tried in the turbines and "stick-slip" tests were then performed. A "stick-slip" test involves recording the pressure differences across the piston in the blade servo and magnitudes of blade motion while the unit is operating. Both large and small blade angle adjustments are made during the test. These tests were eventually performed on all units numerous times. Oils tested were:

- MIL-L Type 2135 TH (original oil, essentially an ISO 68 turbine oil)
- Arco Truslide S-315
- Mobil DTE Type BB
- Mobil DTE Extra Heavy
- Mobil DTE Heavy

Generally the heavier the oil, the better it performs. However, the heavier oils overloaded the governor pumps and the Arco oil left a thick, gummy residue on the parts it came in contact with. The recommended oil was MIL-L-17331, type 2190 TEP. This oil is International Standards Organization (ISO) 78 oil. The number "78" in the designation refers to the oil's viscosity (in centistokes) at 100°F. Higher numbers mean thicker oil. The Mobil DTE heavy oil came closest to matching the type 2190 TEP oil and was eventually put into all of the John Day turbines because small quantities were easily available. It is ISO 100 oil.

Other changes were made as well to improve lubrication. The number of oil grooves in the bushings was tripled, the new bushings had slightly higher lead content, and a thin (0.0005-inch thick) coating of molybdenum disulfide was applied to the new bushings prior to reassembly.

J.2.2. John Day Turbine Repair Supplemental Report (1987)

After receipt of the September 1983 report discussed in the previous section, Corps' headquarters requested additional studies be performed which became a supplemental report titled, *Study for Turbine Repair, Supplement No. 1, Powerhouse Major Rehabilitation Program, John Day Powerhouse, Oregon and Washington* (April 1, 1987). This second report specifically described additional work performed in five areas:

- A finite element analysis (FEA) of the hub to determine if the flexibility of the hub was causing binding of the blade adjustment mechanism.
- Installation of strain gages on selected internal hub parts to verify predicted hub and component stress and strain.
- Updating the summary of stick-slip test results since the publishing of the original rehabilitation report (published in September 1983).
- Performance of a wear analysis of the John Day hub trunnion bushings.
- Performance of a lubricating oils investigation to determine if there were any commercially available oils or oil additive packages which could reduce the static and dynamic friction factors in the blade adjustment mechanism.

The FEA attempt was unsuccessful in yielding meaningful data. However, there was direct evidence from previously disassembled turbines that the hubs were not distorting enough to cause binding in the mechanism.

The wear analysis was performed by Dr. Douglas Godfrey, a retired chemist from Chevron Laboratory. His report indicated there were few effective options available. The high friction loads were primarily due to the materials being used and not the oil. Ideally, the trunnion should have been harder and smoother. However, because the blades and trunnions were a one-piece casting, making such a change was not possible. One of his recommendations, however, was to search for lubricating oils or additives which could improve the lubricity of the oil. This recommendation was followed.

The lubricating oils investigation by Dr. Godfrey (documented in the April 1987 supplemental report) showed static coefficients of friction could be quite high. In his report, *Lubricity Additives for Kaplan Turbines*, revised November 26, 1984, Dr. Godfrey observed static coefficients of friction were as high as 0.37 using Chevron GST 68 turbine oil. Despite the fact that his testing apparatus was relatively crude, Dr. Godfrey was able to get repeatable results.

In his report, Dr. Godfrey recommended three lubricity-enhancing additives which showed great promise of being successfully used in the John Day turbines at a very nominal cost. His testing showed these additives could reduce the friction factor by approximately 15% with either the 2190 TEP oil or the originally supplied oil (2135 TH). Note that the 2135 TH oil is ISO 68 oil which was typically used in all Corps' turbines at the time.

One of the recommendations in the supplemental report was to try one of the additives (Lubrizol 5346) in a John Day turbine and perform stick-slip tests in the field to test its performance. This was done to unit 6 in September of 1986, and a stick-slip test was then performed on October 21, 1986. The apparent coefficient of friction was 0.121 – approximately 10% lower than the previous test result (0.134) performed on June 12, 1986. No subsequent stick-slip tests were performed on unit 6 after the September 1986 test. The cost of the additive was very minor (approximately $1,000) and the cost to install the additive in the hub oil was also quite nominal ($5,000). Despite the very nominal cost, this recommendation was never implemented in any other turbine at John Day or elsewhere. Apparently, it was believed that the repairs to the BLH turbines, which had largely been accomplished, would be permanent and there was no need to improve the oil's lubricity.

J.2.3. Kaplan Turbine Mechanical Tests (1999-2008)

More research on lubricating oils used by Kaplan turbines was performed in 2004 and 2005, which demonstrated that the design coefficient of friction historically used by turbine manufacturers (0.15) was too low. This research was documented in a May 2005 report titled, *Kaplan Turbine Mechanical Tests* by Powertech Labs of Surrey, BC Canada. The objectives of the research were: (1) to develop a new oil test procedure that closely replicates the operating conditions in Kaplan turbines in order to quantify the stick-slip characteristic of each oil; (2) to design and build a testing apparatus which is capable of testing oils in compliance with the new test procedure; and (3) to test a number of lubricating oils to measure their stick-slip characteristic when used with materials and under conditions typically found in Kaplan turbine blade trunnions and adjustment mechanisms. The results showed the static and dynamic coefficients (when tested with five different oils) varied from 0.167 to 0.227 (static) and from 0.150 to 0.195 (dynamic). Some oils consistently performed better than others (i.e., had lower coefficients of friction). The best performing oil was actually a gearbox oil designated MIL-L-17331, type 2190 TEP. This oil is commercially available and is used at other Corps' powerhouses, such as at the Little Rock District's Ozark plant.

J.2.4. Wicket Gate Bushing Tests

A significant amount of testing has also been performed over the years to determine the performance of grease-free bushings for use in the wicket gate mechanisms of Kaplan and Francis turbines. This testing evaluated bearing performance (including friction factors and wear rates) of various bushing materials (including the type of bronze used in the hubs), as well as the commercially available grease-free products. Testing was performed in the dry, in water, and sometimes in turbine hub oil. Among other brands, "Karon V" manufactured by Kamatics Corporation was found to be a high performer.

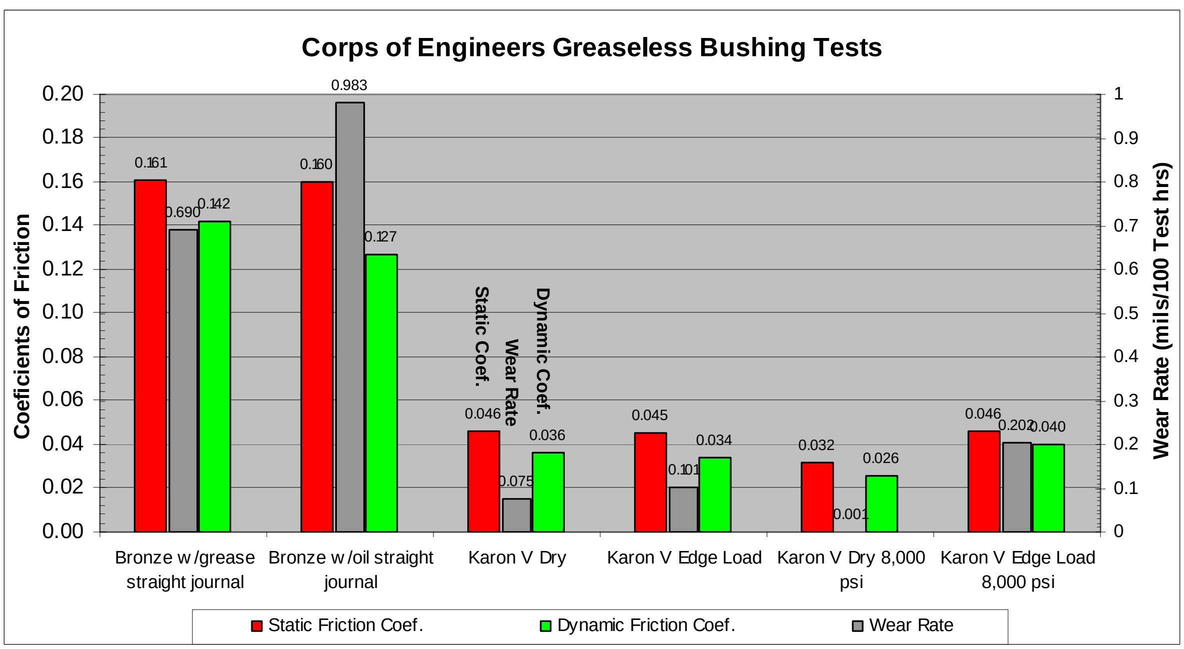
The information in Figure J-1 was taken from a 1999 Corps' Research Laboratory Technical Report 99/104, *Greaseless Bushings for Hydropower Applications: Programs, Testing, and Results*; this report compared friction and wear of oiled/greased bronze and Karon V.

The existing material used for the turbine blade bushings is bronze. The testing in this report shows that on the average the bronze wears more than four times faster than the Karon V material, and that the coefficients of friction (dynamic and static) of bronze, when submerged in oil, is more than 3 times greater than Karon V. Karon V has also been immersed in turbine oil for 225 days with no swelling or degradation.

Karon V is a superior material to the oiled bronze in a bushing application and it was thought that the best way to utilize its good wear and friction characteristics is to apply a thin coating of the Karon V to the bronze bushings using the bronze as a backing plate. The new bushing would use the mechanical strength of the bronze and the low wear and low frictional characteristics of the Karon V to make a bushing that was superior to either of the materials by them selves.

During the recent contract for the refurbishment of unit 2 at Lower Granite, this new hybrid bearing of Karon V on a bronze backing was used to replace the large bronze trunnion bushings (both inner and outer; Photos J-1 and J-2) and to replace the blade link bushings of the blade mechanism. It should be noted that this was the first time a greaseless bushing of this size has been installed inside a turbine hub on a Corps' dam. This unit recently returned to service (January 2009).

Figure J-2. Corps of Engineers Greaseless Bushing Tests



This same material was installed in John Day unit 16 after its failure from a blade link fracture and has been operating with these new Karon V coated bushings since April 2008. In late November 2008 (see Appendix I), stick-slip tests were performed on this unit and two sister units to compare the blade servo effort required to move the blades. The data showed conclusively that the effort (i.e., blade servo oil pressure) to move blades on unit 16 (with the Karon V material) was approximately half of what was required to move the blades of units with oiled bronze bushings.

Photo J-1. Coated Inner Blade Bushing *(~20 inches in diameter)*

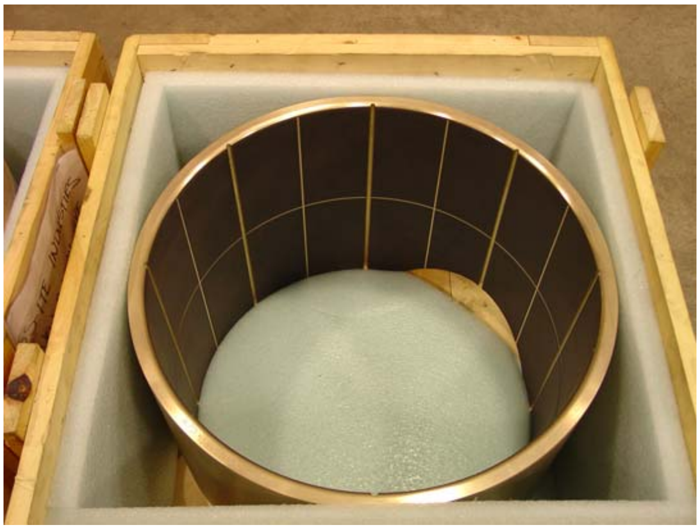


Photo J-2. Coated Outer Blade Bushing *(~36 inches in diameter)*

J.3.0. Summary

- A proactive planned program for inspection of the linkage components inside the runner hubs of the 22 remaining BLH 312-inch units should be considered for implementation. A scheduled in place inspection and repair cost for a single unit is estimated to be $300,000.

- The use of lubricity enhancing additives in the hub oil should be considered due to the small cost and high potential to prolong the remaining life of the internal mechanism. There is approximately 2,200 gallons of oil in a BLH runner hub. Lubrizol 5346 currently costs approximately $70 per 5-gallon pail. At a 2.5% solution, 55 gallons are needed per runner hub. This works out to approximately $800 per hub. However, the cost of mixing the additive into the hub oil as it is re-filled needs to be accounted for as well. In 1986, the project maintenance staff at John Day estimated the labor cost of mixing and installing this additive into an entire generating unit to be approximately $4,000. Using this information, it is estimated that the current labor cost to mix the additive into the hub oil would be approximately $10,000, which includes the cost of an oil compatibility check. The cost for a single unit is estimated to be:

Project Labor Cost	$10,000
Additive Cost	$800
S&A + S&I	$580
Contingencies	$1,620
Total Cost	**$13,000**

- Oils suitable for use in Kaplan turbines are not equal and there can be as much as a 2 to 1 difference in their coefficients of friction. The best performing oil (MIL-L Type 2190 TEP) has been used extensively in Kaplan turbines and should be the oil of choice when new oil is purchased. In January of 2009, a local oil company quoted the cost of this oil to be approximately $10/gallon delivered to John Day powerhouse in quantities of 2,000 gallons or more. The estimated cost to replace all the oil in a single Kaplan unit is shown below, which includes the cost of an oil compatibility check.

Project Labor Cost	$5,000
Contract Cost	$40,000
E&D + S&A + S&I	$8,000
Contingencies	$6,000
Total Cost	**$59,000**

Appendix K
Operational Considerations

Appendix K
Operational Considerations

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K.1.0. Portland District Operational Considerations for John Day Dam

K.1.1. Generation Considerations and Unit Priority

Turbine operation is determined by Project-available inflow and system load demand. The system load is forecast and calculated by Bonneville Power Administration (BPA) dispatchers. The desired Project total generation is sent to the Generic Data Acquisition and Control System (GDACS). The Project Operator starts and stops main unit turbine generator sets, and GDACS adjusts load on the running units. The unit priority and minimum summer flows are primarily determined by the Fish Passage Plan (FPP), which may vary from year to year based on the current Biological Opinion and the configuration of spillway weirs or other changes to fish passage facilities. As required, the unit priority may be adjusted by the Project Operator during scheduled or unscheduled unit outages for maintenance or repair.

Table K-1. Turbine Unit Operating Priority for John Day Dam

Dates	Hours	Unit Operating Priority
1 March - 30 November	24 hours/day	5, 1, 2, 3, 4, then 6-16 in any order
1 December - 28 February	0600 – 2000 hrs	5, then unpaired units any order
	2000 – 0600 hrs	5, then any units

K.1.2. Station Service

The station service transformers (TO1 and TO2) at John Day are fed by one of the first eight main generating units. Main unit 5 is the primary station service unit; when that unit is down for maintenance, one of the other main units 1-4 or 6-8 will be used to feed the station service transformers. However, only unit 5 is configured to feed the station service transformer without first going through the main breakers, which is preferable. As a result, any unit other than unit 5 would be used for station service only on a temporary basis.

Conversion of another main unit to feed station service before the main breaker would include adding a new disconnect at the isophase bus, new isophase bus tap and bus duct to the current-limiting reactor, new non-segregated bus to new breaker, and new high-voltage cable to a selector switch. The cost of this conversion is estimated to be in the range of $150,000.

K.1.3. Synchronous Condensing

John Day units 11-14 have been modified to allow operation as synchronous condensing units. While condensing, the units are operated with the wicket gates closed and the runner blades at full flat. If one or more of these units were to be converted to operating as a propeller unit with a blade angle of 29 degrees, condensing would occur at that blade angle. Testing was performed in January 2009 to determine if there are any potential adverse effects of transitioning to operating in a condensing mode at a 29-degree blade angle. Test results indicate that no difficulties would be encountered with conversion of units 11-14 (see Appendix A and Appendix I).

K.1.4. Runner Work Platforms

John Day has two available runner work platforms that are used for cavitation repair of blade and hub surfaces during scheduled 6-year maintenance outages. Both of these platforms were designed to be in contact with the runner cone when assembled, and derive their structural integrity from attachment to the cone. This design does not allow room for a runner cone to be lowered from the hub within the draft tube. Walla Walla District plants have platforms with a design incorporating a larger opening and different method of support, which does allow the cone to be lowered from the hub. If John Day maintenance staff lower the cone to perform inspections or pre-emptive replacement of certain linkage components, then a new platform would need to be constructed to permit this work. Walla Walla District platform drawings are available and little additional design work should be necessary to procure a platform (~$80,000).

On 6 January 2009, a meeting was held with the Hydroelectric Design Center (HDC) and Project staff to discuss what work could be completed with the runner cone lowered inside the draft tube. Due to difficult access, interference between parts, and the weight of many components, replacement of linkage components is limited to the lower pins. Other parts can be inspected for fatigue cracking using ultrasonic or die-penetrant testing methods, but safe replacement without unstacking is not possible.

K.1.5. Spare Parts

No spare linkage components (upper and lower pins, link plates and studs, and eye ends) for the subject BLH turbines are currently available. Purchase and manufacture of replacement steel linkage components can take a year or more. Dimensions of the steel components do not depend on field measurements collected after disassembly, so these parts could be completed in advance. Availability of spare sets of these long lead-time parts would drastically reduce the time a failed unit would remain out of service. John Day currently has a spare set of blade bushing blanks on hand as spares. Stick-slip testing has validated the value of using greaseless coatings on blade and linkage bushings to reduce friction and actuation forces, with a resultant increase in fatigue life. Final blade bushing dimensions are determined by field measurements; however, the greaseless coating could be pre-applied to bushing blanks, and the final machining processes could be performed onsite by John Day mechanics.

A complete set of spare parts is being procured through a subagreement and expected to arrive at John Day in September 2009. This single set of spare parts is a regional set for the remaining 22 BLH-312 inch Kaplan’s and will be stored at John Day until needed. The disposition and replacement of these spare parts to repair a failed mechanism or for use in major maintenance activity is a Capital Work Group decision. Should the proactive repair before failure strategy of Appendix J be implemented, additional link pins and associated consumable parts will need to be separately procured because they are not in the spare parts inventory.

K.1.6. Project Labor and Equipment

Project maintenance staff, including mechanics, machinists, riggers, and electricians, have invaluable experience with turbine-generator set disassembly, overhaul, reassembly, and testing required for return to service. Over the years, the staff has refined procedures, and where necessary has fabricated tooling required for completing this work. However, significant work beyond the scope of scheduled maintenance activities increases the challenge of maintaining other critical plant equipment. If Project staff is to be used to complete comprehensive inspections or overhauls in the future, it is expected that additional permanent or temporary employees would be required to complete all maintenance activities.

K.1.7. Summary Information

Generation Considerations:

- Run units within ± 1% efficiency range: ~90-95 megawatts (MW) minimum, 135 MW maximum.
- Split pairs of units on one line for voltage control. For example, if unit 5 is running on line 2, then units 7 or 8 would be brought on before unit 6.
- Synchronous condensing: units 11-14 as required.
- Station service: Transformers have been configured to make unit 5 the preferred station service unit, but other units 1-4 or 6-8 can be used temporarily to feed station service, as required.

Required Spill Considerations:

- Summer spill season: 60% of total cfs spill required from 1800 - 0600.
- Top spillway weir (TSW) support will result in adjustments to the previous non-TSW spill patterns.
- TSW data and changing Biological Opinions may allow changes in required spill volume or dates.
- If any units are repaired to propeller status, then the existing powerhouse hydraulic capacity may need to be reduced.

Units to Remain Kaplan:

- Operationally one unit in the 1-8 group must be retained as a Kaplan for station service; unit 5 is the preferred unit.

K.2.0. Walla Walla District Operational Considerations for BLH Units

K.2.1. Generation Considerations for Lower Monumental, Little Goose and Lower Granite Dams

Turbine operation is determined by Project-available inflow and system load demand. The system load is forecast and calculated by BPA dispatchers. The desired Project total generation is sent to the GDACS. The Project Operator starts and stops turbine generator sets at the request of the BPA dispatchers, usually referred to as main unit or unit, and GDACS adjusts load on the running units. The GDACS has a default unit start and stop priority sequence. The Project Operator can change that sequence and does so according to the current FPP.

K.2.2. Unit Priorities

The only operational priorities requiring a BLH unit at any of the three projects to be retained as a Kaplan are fish passage priorities. These are discussed in Appendix B. The 2008 FPP requirements are repeated here in Tables K-2, K-3, and K-4 for clarity. Turbine unit operating priority may be coordinated differently to allow for fish research, construction, or project maintenance activities. If a turbine unit is taken out of service for maintenance or repair, the next unit on the priority list will be operated.

Lower Monumental Dam History. Units 1, 2 and 3 turbines were completely rebuilt due to internal wear and damage and returned to full Kaplan operation shortly after initial installation. Other reports address the history of these turbine problems. The blade linkages for unit 1 failed in 2006 and the decision was made to weld the blades into a fixed position, and to maintain the Kaplan static head oil system in order to preserve the internal turbine runner components. The turbine will be repaired and restored to Kaplan adjustable-blade configuration. This work is tentatively scheduled to begin in January 2010 and to be completed May 2011.

Table K-2. Turbine Unit Operating Priority for Lower Monumental Dam

Season	River Flow	Spill Level	Unit Priority
1 March - 30 November	Less than 75 kcfs	While spilling 50%	2, 5*, 3, 4, 6 then 1
	75 to 100 kcfs	While spilling 45%	2, 5*, 3, 4, 6 then 1
	Over 100 kcfs	While spilling 50% or to gas cap	1**, 5*, 2, 3, 4, then 6
	Any river flow	No spill	2, 3, 4, 5, 6 then 1***
1 December - 28 February	Any river flow	Any spill level, including no spill	Any order

*If U5 is OOS, run U4. **If U1 is OOS, run U2. ***If no spill is occurring, U1 may be operated at any priority level at the discretion of project personnel. NOTE: U1 has fixed-pitch blades and can temporarily be operate only at about 130 megawatts until repaired. When U1 is repaired the unit priorities will change.

At Lower Monumental Dam, the minimum generation requirements are 11 - 12 kcfs for turbine units 1-3 and 17 - 19 kcfs for turbine units 4-6.

Little Goose Dam History. Units 1, 2 and 3 turbines were completely rebuilt due to internal wear and damage and returned to full Kaplan operation. None have since failed.

Table K-3. Turbine Unit Operating Priority for Little Goose Dam

Season	Time of Day	Unit Priority
1 March - 31 October	24 hours	1, 2, 3, 4, 5, 6 (maximize discharge through lowest numbered turbine units)
1 December - 28 February	24 hours	Any order

At Little Goose Dam, the minimum generation requirements are 11 - 12 kcfs for turbine units 1-3 and 17 - 19 kcfs for turbine units 4-6.

Lower Granite Dam History. Units 1, 2 and 3 were the last to be built of the BLH series. Unit 2 failed, was repaired (similarly to John Day unit 16) to full Kaplan operation and was returned to satisfactory service on 29 January 2009.

Table K-4. Turbine Unit Operating Priority for Lower Granite Dam

Season	Time of Day	Unit Priority
1 March - 15 December	24 hours	1, 2, 3, then 4-6 (any order)
1 April - 31 October (if there is enough flow to run priority units)	Nighttime (2000 to 0400 hours)	4-6 (in any order, then 1-3 (as needed)
16 December - 28 February	24 hours	Any order

At Lower Granite Dam, the minimum generation requirements are 11 - 12 kcfs for turbine units 1-3 and 17 - 19 kcfs for turbine units 4-6.

In order to minimize mortality to juvenile fish passing through the turbine units from April 1 through October 31 at Lower Granite Dam (or as long as there is sufficient river flow and/or generation requests to operate turbine units 4, 5, or 6 within 1% of best turbine efficiency), operating priority during nighttime hours from 2000 to 0400 hours shall be units 4, 5, and 6 (in any order) and then units 1, 2, and 3 as needed (see Table K-4).

K.2.3. Station Service

Station service at all three projects can be supplied by other than the BLH units and does not influence the Kaplan or fixed blade repair strategy. All of the lower Snake River powerhouses may be required to keep one generating turbine unit on line at all times to maintain power system reliability. During low flows, there may not be enough river flow to meet this generation requirement and required minimum spill. Under these circumstances, the power generation requirement will take precedence over the minimum spill requirement.

K.2.4. Synchronous Condensing

There is no synchronous condensing provided by any of the three projects; hence this does not influence the Kaplan or fixed-blade repair strategy.

K.2.5. Runner Work Platforms

The runner work platforms at all three projects are satisfactory for continued use.

K.2.6. Spare Parts

No spare linkage components (upper and lower pins, link plates and studs, and eye ends) for the Snake River BLH turbines are currently available. Should the proactive repair before failure strategy of Appendix J be implemented, additional link pins and associated consumable parts will need to be procured. A complete set of spare parts is being procured through a subagreement and expected to arrive at John Day in September 2009. This single set of spare parts is a regional set for the remaining 22 BLH-312 inch Kaplan's and will be stored at John Day until needed. The disposition and replacement of these spare parts to repair a failed mechanism or for use in major maintenance activity is a Capital Work Group decision.

K.2.7. Project Labor and Equipment

Project maintenance staff, including mechanics, machinists, riggers, and electricians, have invaluable experience with turbine-generator set disassembly, overhaul, reassembly, and testing required for return to service. Over the years, the staff has refined procedures, and where necessary, has fabricated tooling required for completing this work. However, significant work beyond the scope of scheduled maintenance activities increases the challenge of maintaining other critical plant equipment. If Project staff is to be used to complete comprehensive inspections or overhauls in the future, it is expected that additional permanent or temporary employees would be required to complete all maintenance activities.

K.2.8. Summary Information

Generation Considerations:

- Run units within ± 1% efficiency range.

Required Spill Considerations:

- If any units are repaired to propeller status, the existing powerhouse hydraulic capacity may need to be reduced.
- Required spring spill season begins April 3rd and ends June 20th.
- Summer spill season begins June 21st and ends August 31st. Spill amounts vary by project, river conditions, and time of year. According to conditions in the Biological Opinion, Tables K-5 and K-6 show the proposed 2009 spring and summer spill levels.

Table K-5. Summary of 2009 Spring Spill Levels

Project	Planned Operations for Spring 2009 (day/night)	Operational Spill Levels	Comments
Lower Granite	20 kcfs / 20 kcfs	20.4 kcfs	Will fluctuate due to project head changes
Little Goose	30% / 30% (install and test a new adjustable prototype TSW)	30% +/- 1% hourly	Target 30% as a day average
Lower Monumental	gas cap / gas cap bulk spill pattern, approx. 27 kcfs day/night (continue RSW tests)	spill cap day/night	Meet spill cap daily, using FPP bulk spill patterns
Ice Harbor	35% / 35%	35% +/- 1% hourly	Target 35% as a day average
McNary	40% / 40% (continue prototype TSW tests)	40% +/- 1% hourly	Target 40% as a day average

Table K-6. Summary of 2009 Summer Spill Levels

Project	Planned Operations for Summer 2009 (day/night)	Operational Spill Levels	Comments
Lower Granite	18 kcfs / 18 kcfs	18.6 kcfs	Will fluctuate due to head changes
Little Goose	30% / 30% (test adjustable prototype TSW)	30% +/- 1% hourly	Target 30% as a day average
Lower Monumental	17 kcfs / 17 kcfs (continue TSW tests)	17.1 kcfs	Will fluctuate due to head changes
Ice Harbor	30% / 30%	30% +/- 1% hourly	Target 30% as a day average
McNary	50% / 50% (continue prototype TSW tests)	50% +/- 1% hourly	Target 50% as a day average

Units to Remain Kaplan:

- Operationally the BLH units at all three projects could be repaired to propeller operation; however, the environmental requirements discussed in Appendix B indicate that units 1 and 2 at each project should be repaired to Kaplan operation.

Appendix L
Glossary

Appendix L – Glossary

This glossary defines terms that are specific to the report, *Kaplan Turbine Repair Strategy, John Day Units 1-16 and Lower Monumental, Little Goose, and Lower Granite Units 1-3*.

Acoustic Doppler Velocimeter – An acoustic doppler velocimeter measures the velocity of a liquid through a conduit using acoustic sensors (also referred to as time of flight).

Air Bladder – The organ a fish uses to control its buoyancy in water. To float it fills this bladder with gas, expanding the fish in volume, which decreases its density (also called swim bladder).

Anadromous Fish – Fish which spawn in fresh water, but live most of their lives in the ocean; includes all salmonid species.

Balloon Tag – A small balloon attached to a fish into which chemicals are inserted causing the balloon to inflate after a few minutes, allowing for easier recovery of the fish for examination after it passes through a turbine, spillway, or other dam structure (also called Hi-Z Turb'n Tag).

Bead – Neutrally buoyant (same density as water) bead used to simulate fish in model testing.

Biological Opinion – Produced by the National Marine Fisheries Service, this document is a plan for recovery of threatened and endangered fish stocks that defines which stocks are considered threatened or endangered, and identifies legally enforceable actions that must be taken to achieve recovery of stock.

Biological Index Testing – Operation of a hydropower project to optimize fish passage.

Blade Levers – The levers attached to the blade trunnions that translate vertical motion of the blade links to rotation of the blades.

Blade Links (Inside and Outside) – Blade operating elements that connect the blade levers to the crosshead eye ends through the link pins.

Blade Servomotor – The hydraulic cylinder actuated by governor oil pressure which supplies the force necessary to adjust the runner blades.

Cavitation – Cavitation results when water flow reaches a zone of low pressure where bubbles form, followed by a zone of high pressure that causes the bubbles to collapse. The collapse of these bubbles is violent enough to form very strong localized shock waves, potentially harming nearby fish and causing damage to of equipment surfaces.

COMPARE Spreadsheet – Applies Bonneville Power Administration power values to a Turbine Energy Analysis Model (TEAM) estimate of project energy production to develop the corresponding estimate of project hydropower benefits.

Computational Fluid Dynamics (CFD) – Numerical models that estimate fluid flow field characteristics.

Crosshead – The member that is attached to the blade servomotor and through the links and blade levers to transmit the operating force to all blades simultaneously. It has as many arms as the turbine runner has blades.

Cubic feet per second (cfs) – Quantity of water flow.

Dewater – The act of emptying the water from fluid passageways within the project to provide access for maintenance.

Distributor – A ring around a turbine runner composed of the stay vanes and wicket gates. The stay vanes carry the structural weight and the wicket gates rotate to adjust the flow.

Draft-tube Barrels – A structural pier that separates the draft-tube into two sections to direct discharge in a downstream direction.

Draft-tube Exit – The exit area of the draft-tube where discharge expands to the tailwater level.

Draft-tube and Elbow – A shaped diffuser tube below the turbine runner in which velocity and pressure heads are recovered.

Extended-Length Submerged Bar Screens (ESBS) – Turbine intake screens that are approximately 40 feet that divert fish from the upper portion of the turbine intakes to a juvenile bypass system.

Eye End – An element of the blade operating mechanism that connects the crosshead to the blade links through link pins.

Federal Columbia River Power System (FCRPS) – A collaboration of federal agencies (Bonneville Power Administration, Corps of Engineers, and Bureau of Reclamation) in the Pacific Northwest to coordinate the federal hydropower system and maximize the use of water resources available for power generation, protecting fish and wild life, controlling floods, providing irrigation and navigation, and sustaining cultural resources.

Fish Facility Design Review Work Group (FFDRWG) – A regional multi-agency group focused on fish passage mitigation measures.

Fish Passage Operations Maintenance Coordination Team (FPOM) – A regional multi-agency group focused on coordinating operation and maintenance of facilities to mitigate effects on fish passage.

Fish Passage Plan (FPP) – The annual FPP is developed by Corps of Engineers in conjunction with Bonneville Power Administration and other parties to describe the year-round project operations necessary to protect and enhance anadromous and resident fish species listed as endangered or threatened under the Endangered Species Act, as well as other migratory fish species.

Fixed Blade – A adjustable blade runner (Kaplan) modified to eliminate the ability to rotate the runner blades.

Generic Data Acquisition and Control System (GDACS) – A Corps of Engineers overarching control system to monitor and operated the Federal Columbia River Power System.

Heavy Load Hours (HLH) – The 66-hour sub-period representing the heavy load (on-peak) demand hours of the week (not including the 30 super-peak hours). Used by the Turbine Energy Analysis Model (TEAM) and COMPARE spreadsheet.

Hydro System Seasonal Regulation (HYSSR) Model – Provides 50-year hydrologic period of record project monthly flow releases and forebay elevations as input to the Turbine Energy Analysis Model (TEAM).

Index Testing – A means of defining, in relative or absolute terms, performance of a turbine/generator unit, typically for determining the unit's performance over the range of generator output up to full output.

Intake Bays – The bays in the intake structure used to distribute flow to the turbine scroll case. Most large Kaplan turbines have three bays but some may have two or less.

Internal Rate of Return (IRR) – The rate of return that generates a zero net present value (NPV) for a stream of cash flows.

John Day Project (JDA) - A 16-unit powerhouse containing all Baldwin-Lima-Hamilton Kaplan turbines.

Kaplan Turbine – A reaction-type, vertical shaft turbine, with adjustable blades designed to optimize turbine performance and operate over a relatively low-head range, from about 100 to 50 feet of head.

Laser Doppler Velocity System (LDV) – A laser measurement system used to measure water velocity at discrete locations in a water passage.

Light Load Hours (LLH) – The 72-hour sub-period representing the light load (off-peak) demand hours of the week. Used by the Turbine Energy Analysis Model (TEAM) and COMPARE spreadsheet.

Link Pins – Two pins (one upper and one lower for each blade) used to "pin" moving parts together.

Little Goose Project (LGS) – A six-unit powerhouse containing two families of turbine designs with units 1-3 being Baldwin-Lima-Hamilton Kaplan turbines.

Lower Granite Project (LWG) – A six-unit powerhouse containing two families of turbine designs with units 1-3 being Baldwin-Lima-Hamilton Kaplan turbines.

Lower Monumental Project (LMN) – A six-unit powerhouse containing two families of turbine designs with units 1-3 being Baldwin-Lima-Hamilton Kaplan turbines.

Minimum Operating Pool (MOP) – The operating pool elevation which is the desired pool elevation during the fish passage season.

Nadir – As used in this report, it is the lowest point.

Net Present Value (NPV) – The difference between the present value of cash inflows (benefits) and the present value of cash outflows (costs).

Off Cam – Kaplan turbine operation where the blade angle is not optimized with the existing net head and wicket gate position. Originally the blade angle was controlled by a series of cams or by a three-dimensional cam hence the term “not on cam.” Being “off cam” means operation at decreased efficiency due to incidence effects, which creates more turbulence.

On Cam – Kaplan turbine operation on an envelope curve in which turbulence is minimized and efficiency maximized thorough unique optimal blade angles and gate openings.

One Percent (1%) Rule – A requirement listed in the National Marine Fisheries Service’s 1995 Biological Opinion that specifies that turbines should be operated within 1% of best operating efficiency. It was established based on the theory that water flow through the turbines is less turbulent when near maximum efficiency.

Passive Integrated Transponder (PIT) – An electronic device about the size of a grain of rice that is implanted in juvenile fish. The device provides the fish with a unique identification number and permits it to be tracked during downstream migration through the hydropower system as a juvenile and later upstream as an adult.

Present Value (PV) – The current worth of a stream of cash flows given a specified rate of return.

Propeller – A turbine runner specifically designed to operate with runner blades set in a fixed position.

Run-of-the-River – When the existing river flow at a particular time is passed through a dam with little storage available.

Runner Chamber – The zone containing the stationary and rotating components of the turbine that convert waterpower to shaft power. It is composed of the discharge ring, head cover, runner blades, hub, and cone.

Scroll Case – A volute-shaped chamber directing water uniformly to the distributor.

Shear Injury – Water shear results when two parallel jets of differing velocities of water pass next to or near to each other. Shear injuries may include head damage, torn opercula (gill covers), loss of scales, and damaged or missing eyes. Less severe injuries may include loss of equilibrium and disorientation.

Standard Error (SE) – Estimates the standard deviation of the difference between the measured or estimated values and the true values.

Stay Vanes – Stationary vanes arranged in the stay ring upstream from the wicket gates carrying the structural weight and positioned to operate with the wicket gates.

Strike Injury – Strike injuries result from fish hitting solid parts of the machine, both moving parts and those that are stationary.

Submerged Traveling Screen (STS) – Turbine intake screens that are approximately 20 feet that divert fish from the upper portion of the turbine intakes to a juvenile bypass system.

Super Peak (SP) Hours – The 30-hour sub-period representing the highest valued heavy load (on-peak) demand hours of the week. Used by the Turbine Energy Analysis Model (TEAM) and COMPARE spreadsheet.

Swim Bladder – See air bladder.

Tailrace – The region downstream of the dam, beginning at the downstream end of the stilling basin or a short distance down from the draft-tube exit, where water in the channel becomes shallower and narrower.

Trash Rack – Steel grating to keep trash from damaging the turbine.

Trunnions (Runner Blade) – The shaft segments integral with or bolted to the runner blades. The trunnions provide the rotational axis and transfer the rotating action of the operating mechanism to the runner blades and support the blades in the hub bearings.

Turbine Energy Analysis Model (TEAM) – Used to estimate project energy production for each year and week in the 50-year hydrologic period of record.

Turbine Passage Survival Program (TSP) – A Corps of Engineers program to investigate mechanical and operational changes that can be made to hydropower dam turbines to increase fish passage survival and power production benefits.

Vertical Barrier Screen (VBS) – Permanent stationary screens located in turbine intake slots used to divert migrating fish to fish collection channels.

Wicket Gates – A gate in the flow of water to turbine blades that regulates quantity and direction; or a series of movable, flow-regulating, gates that impart a whirling component to axial flow.