Docket	:	A.23-12-014
Exhibit Number	:	
Commissioner	:	John Reynolds
Admin. Law Judge	:	J. Regnier
Witnesses	:	Paul Worhach
	:	Kaj Peterson

PUBLIC ADVOCATES OFFICE

CALIFORNIA PUBLIC UTILITIES COMMISSION

PREPARED TESTIMONY ON THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) TO RECOVER HELMS UPRATE COSTS

(PUBLIC VERSION)

San Francisco, California
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MEMORANDUM

This testimony was prepared by the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) for Pacific Gas and Electric Company's (PG&E) Application 23-12-014 (Application). In this proceeding, PG&E requests the California Public Utilities Commission (Commission) to find, among other things, that the Helms Uprate Project is cost-effective[1] and that its forecast of $462 million in capital expenditures is reasonable,[2] as well as authorize it to recover up to $462 million without further reasonableness review.[3] In this testimony, Cal Advocates presents its analyses and recommendations associated with PG&E's requests.[4]

Paul Worhach serves as Cal Advocates' project coordinator in this review and is responsible for the overall coordination in the preparation of this testimony. The witnesses' prepared qualifications and testimony declarations are contained in Appendix A of this report.

List of Cal Advocates' Witnesses and Respective Chapters

Chapter Number	Description	Witness(es)
-	Executive Summary	Worhach
1	Evaluation	Worhach/Peterson
2	Cost-Effectiveness	Worhach

[1] Application at 32.

[2] Application at 33.

[3] Application at 33.

[4] Application at 32-34.

EXECUTIVE SUMMARY (Worhach)

Pacific Gas and Electric Company (PG&E) seeks approval from the California Public Utilities Commission (Commission) to recover capital costs for the proposed Helms pumped storage hydroelectric facility uprate project (Helms Uprate or Uprate).[5] PG&E proposes to integrate the Uprate with work to extend the useful life of the Helms facility (Lifecycle Replacement) and to recover capital costs of up to $462 million for the combined Uprate and Lifecycle Replacement work without further reasonableness review, including $154 in unknown contingency costs.[6] PG&E's request is premature and includes too many uncertainties at this time to determine whether it is reasonable.

PG&E claims that the Helms Uprate and Lifecycle Replacement work is a cost-effective solution to meet California's affordability, climate, and resiliency goals.[7] However, the inherent uncertainties in PG&E's early-stage, preliminary, and conceptual design belie PG&E's claims that its up-front cost recovery request of $462 million for the Uprate and Lifecycle work is reasonable. PG&E's cost-effectiveness analysis does not sufficiently address project uncertainty and thus should not be used to find that the costs for the Uprate and Lifecycle Replacement work are reasonable. Furthermore, PG&E does not demonstrate that the project is the best value for ratepayers compared with other options for long-duration energy storage.

This testimony examines how the many Helms Uprate and Lifecycle Replacement uncertainties may negatively impact the cost, schedule, and cost-effectiveness of the project. Cal Advocates' evaluation demonstrates that PG&E does not provide sufficient information for the Commission and parties to determine if the project as presented in the Application is reasonable. PG&E's early-stage, highly uncertain design and development plan does not justify the use of a 50% contingency to insulate itself from uncertainty while passing on unknown costs to ratepayers. Consequently, the Commission should

[5] Application at 1.

[6] Application at 19; PG&E Prepared Testimony (PG&E Testimony), Chapter 3, Attachment C, Independent Evaluator Report (IE Report) at 3-AtchC-3.

[7] Application at 1.

not approve PG&E's request for an up-front approval of a $462 million maximum cost cap.

CHAPTER 1 : HELMS UPRATE PROJECT EVALUATION

(Witnesses: Paul Worhach, Kaj Peterson)

I. INTRODUCTION (Worhach)

PG&E seeks Commission approval to recover certain capital costs for the proposed Helms Uprate to increase the nameplate generating capacity of the existing Helms facility.[8] The proposal would integrate the Uprate with Lifecycle Replacement work to extend the useful life of the Helms facility and to recover capital costs for the combined Uprate and Lifecycle Replacement work.[9] The Lifecycle Replacement work, according to PG&E, is needed over the next 10 years[10] to replace many of the major generation equipment components and extend the expected useful life of the existing three unit, 1,212 mega-watt (MW) Helms facility to 38 years.[11] PG&E anticipates that the combined Helms Uprate and Lifecycle Replacement work will qualify for a 30% Investment Tax Credit (ITC) under the Inflation Reduction Act of 2023 (IRA).[12]

PG&E's total cost estimate for the combined work is $462 million, composed of $200 million for the Lifecycle Replacement, an incremental $100 million for the Uprate, $8 million for associated interconnection upgrades for the Uprate, and $154 million in continency costs.[13] PG&E states that its cost forecast corresponds to an Association for the Advancement of Cost Engineering (AACE) Class 5 estimate, which indicates that the project is in an early conceptual and preliminary design phase and carries significant uncertainties and risks.[14] PG&E acknowledges project uncertainties related to California Independent System Operator (CAISO) interconnection and Federal Energy Regulatory

[8] Application at 1.

[9] Application at 19; IE Report at 3-AtchC-3.

[10] PG&E Testimony at 1-1.

[11] Application at 11.

[12] Application at 8.

[13] PG&E Testimony at 2-12 – 2-13.

[14] Application at 32; PG&E Testimony at 1-2 and 2-11.

Commission (FERC) relicensing requirements,[15] actual uprated generation and pumping capacity,[16] eligibility of the Lifecycle Replacement work for the ITC,[17] climate resiliency and drought,[18] and environmental review.[19] Notwithstanding the significant uncertainties in its conceptual, early-stage design, PG&E requests that the Commission find reasonable its $462 million capital cost forecast, including the $154 million contingency to cover unknown project costs without further reasonableness review.[20]

On September 30, 2024, PG&E filed supplemental testimony (PG&E Supplemental Testimony)[21] in which PG&E states that the earliest date for Full Capacity Deliverability Status (FCDS) and Resource Adequacy (RA) value is mid-2040.[22] As a result of the delay in FCDS and RA eligibility to at least 2040, the net market value (NMV) of the Helms Uprate has "declined considerably"[23] in contrast to the NMV values presented in original Application.

This chapter examines how the many project uncertainties may negatively impact the cost, schedule, and cost-effectiveness of the project. Cal Advocates' evaluation demonstrates that PG&E does not provide sufficient information for the Commission and parties to determine if the project as presented in the Application is reasonable.

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[15] PG&E Testimony at 4-8.

[16] Application at 10; IE Report at 3-AtchC-14.

[17] Application at 14.

[18] Attachment 1, PG&E Response to Public Advocates Office Data Request 001, Question 27, at 1.

[19] Application at 27, Footnote 38; PG&E Testimony at 3-12.

[20] Application at 33.

[21] PG&E Updates Regarding the Interconnection Process and Timeline for the Helms Uprate Project, Supplemental Testimony (PG&E Supplemental Testimony), September 30, 2024.

[22] PG&E Supplemental Testimony at 10.

[23] PG&E Supplemental Testimony, Attachment B, Independent Evaluator Addendum for Helms Uprate at 4.

II. DISCUSSION

A. The Application is Premature and Lacks Sufficient Information for the Commission to Determine if the Project is Reasonable (Worhach)

PG&E provides insufficient information for the Commission to evaluate the reasonableness of its request to recover up to $462 million without further reasonableness review. PG&E has not performed the necessary engineering design that would provide sufficient information,[24] and the regulatory processes at FERC,[25] CAISO,[26] and the U.S. Department of Treasury[27] remain at an early stage.[28] The Application is premature because the information that is necessary for the Commission to evaluate the reasonableness of PG&E's requested relief is not yet available. PG&E's proposed 50% contingency represents $154 million in unknown project costs[29] that will effectively insulate PG&E from cost overruns and pass on the risk of higher costs and lower than expected project value to ratepayers.

PG&E previously sought authority to record the costs of the Helms Uprate project in a memorandum account in its Test Year 2023 General Rate Case (GRC) application.[30] The Utility Reform Network (TURN) objected to the creation of a Helms Capacity Memorandum Account as premature because, among other things, PG&E had not yet developed a forecast of costs or determined whether the project is cost-effective.[31] In support of its request, PG&E stated that the project was being undertaken in response to a Commission-identified need for long duration storage but that the project was at the very early stages of development, and thus PG&E did not forecast capital expenditures in the

[24] Application at 32.

[25] Application at 12.

[26] PG&E Supplemental Testimony at 7.

[27] Application at 14.

[28] Application at 12.

[29] PG&E Testimony at 2-12.

[30] Application at 2, citing to Application A.21-06-021 (PG&E GRC Application) at 9.

[31] PG&E GRC Application, Opening Brief of The Utility Reform Network at 528.

GRC proceeding.[32] As approved in D.23-11-069 on November 16, 2023, PG&E stipulated to withdraw its request in the GRC, and the parties agreed that PG&E could seek cost recovery "if those costs are found reasonable, the project is cost-effective, and PG&E has sought project approval in a future proceeding."[33]

PG&E filed the pending Application 22 business days after D.23-11-069 was issued.[34] Contrary to the 2023 GRC stipulation between PG&E and TURN, PG&E does not provide sufficient evidence that the proposed Helms Uprate and Lifecycle Replacement work is reasonable and cost-effective. The additional information that PG&E provided in the Application is limited to a superficial and highly uncertain cost forecast.[35] Moreover, the information that PG&E provides remains in such an early conceptual design stage,[36] corresponding to the highest level of uncertainty in the AACE cost classification system,[37] that PG&E is compelled to include a large cost contingency in its cost forecast.[38] For example, the preliminary project engineering design and lack of generation turbine testing, estimated construction plan and timeline, undeveloped environmental review, yet-to be adopted federal tax guidelines for the ITC, and projected processes to obtain needed permits and licenses are all inchoate and unripe.[39] PG&E's Supplemental Testimony compounds the uncertainties in the Application due to the delay of the CAISO interconnection study process by a minimum of two years and the ineligibility for RA value until at least 2040.[40]

[32] D.23-11-069 (PG&E 2023 GRC Decision) at 507-408.

[33] PG&E 2023 GRC Decision at 507-508.

[34] A.23-12-014 was filed on December 20, 2023.

[35] Attachment 2, PG&E Response to Cal Advocates Data Request 001, Question 13.f, at 5. PG&E indicates that it utilized approximately four staff and 165 person-hours to develop the Uprate cost forecast.

[36] IE Report at 3-AtchC-19.

[37] PG&E Testimony at 2-11.

[38] Application at 2; PG&E Testimony at 2-11, 2-12.

[39] PG&E Testimony at 1-2, 2-11, 3-14, 4-5, and 5-8.

[40] PG&E Supplemental Testimony at 10.

As detailed in the following sections, PG&E makes numerous claims about the Helms Uprate which require additional information. These factors will have an undetermined impact on the realized cost-effectiveness of the project. The Commission and parties need more certain information than PG&E has available to evaluate PG&E's claim that the proposed Uprate and Lifecycle costs are reasonable.

B. The ITC Eligibility of the Lifecycle Replacement Work is Uncertain (Worhach)

PG&E assumes that the costs of both the Uprate and the Lifecycle Replacement components will qualify for the 30% ITC under the IRA – resulting in a $135 million tax credit that would offset the $462 million cost forecast.[41] PG&E indicates that its understanding of the ITC is based upon the Internal Revenue Service (IRS) proposed guidelines for the IRA as of November 30, 2023.[42] However, the IRS announced updated proposed guidelines on May 29, 2024 that include new rules that govern ITC eligibility for capacity additions to existing facilities.[43] In response to a data request, PG&E indicates that its understanding and interpretation of the revised guidelines does not change its assumption that the Lifecycle Replacement as well as the Uprate will be eligible for the 30% ITC.[44]

In contrast to PG&E's assumptions, the National Hydropower Association (NHA)[45] and the Business Council for Sustainable Energy (BCSE),[46] two trade

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[41] PG&E Testimony at 2-11.

[42] PG&E Testimony at 4-5, Footnote 6.

[43] IRS, *Treasury, IRS issue proposed regulations for owners of qualified clean electricity facilities and energy storage technologies*, May 29, 2024. Available at: https://www.irs.gov/newsroom/treasury-irs-issue-proposed-regulations-for-owners-of-qualified-clean-electricity-facilities-and-energy-storage-technologies.

[44] Attachment 3, PG&E Response to Public Advocates Office Data Request 009, Question 1, at 1.

[45] National Hydropower Association Comments on Section 45Y Clean Energy Production Credit and Section 48E Clean Energy Investment Credit (REG-119283-23) proposed rulemaking (NHA Comments). Available at: https://www.regulations.gov/comment/IRS-2024-0026-1637.

[46] Business Council for Sustainable Energy Comments on Section 45Y Clean Energy Production Credit and Section 48E Clean Energy Investment Credit (REG-119283-23) proposed rulemaking (BCSE Comments). Available at: https://www.regulations.gov/comment/IRS-2024-0026-1693.

associations of which PG&E is a member,[47] submitted public comments on the proposed regulations that express concern that there is uncertainty in how the new rules for capacity additions will be applied. NHA indicates that the proposed rules could "[limit] the amount of qualified investment for purposes of the ITC under Section 48E to a fraction representing the increase in production,"[48] and requests that IRS clarify the rules relating to new units and additions of capacity to an existing facility.[49] BCSE states that contrary to prior ITC rules, "… the proposed rule would require taxpayers to calculate their qualified investment as the pro-rata share of the capacity increase."[50] BCSE also requests that the IRS clarify the rules for ITC eligibility for capacity additions.

The accounting firm KPMG agrees with NHA and BCSE that the proposed rules for capacity additions to existing facilities would result in a much lower ITC benefit. In a report released on June 12, 2024, KPMG states:

> In the case of a new unit or an increase in capacity, the amount of the investment tax credit is multiplied by a fraction, the numerator of which is the increase in nameplate capacity and the denominator is the total nameplate capacity. This is a departure from current law section 48E, which doesn't provide a similar rule.[51]

The final disposition of the applicable rules is still pending, so any forecast of ITC benefits is speculative at best. It is far from clear how much of PG&E's total project cost will, or will not, qualify for the credit. If the final adopted rule specifies that only the incremental expanded capacity is eligible for the ITC, as is the concern of NHA and

[47] See https://www.hydro.org/membership/members-directory/?44468_search=pacific+gas+and+electric and https://bcse.org/join-our-coalition/#members.

[48] NHA Comments at 28.

[49] NHA Comments at 3.

[50] BCSE Comments at 4.

[51] KPMG, *Section 45Y clean electricity production credit and section 48E clean electricity investment credit proposed regulations*, June 12, 2024 (KPMG report) at 7. Available at: https://kpmg.com/kpmg-us/content/dam/kpmg/taxnewsflash/pdf/2024/06/kpmg-report-sections-45Y-48E-proposed-regs.pdf.

BCSE, the realized ITC benefit could be as low as $15 million instead of the $135 million projected by PG&E.[52]

PG&E proposes to inform the Commission in a Tier 1 advice letter if the Helms Uprate and the Lifecycle Replacement work does not qualify for the full 30% ITC.[53] PG&E acknowledges that there is uncertainty in how the ITC provisions in the IRA will be interpreted and applied by the United States Department of Treasury.[54] If the costs of the combined Uprate and Lifecycle work do not qualify for the full 30% ITC, as PG&E assumes, the value to ratepayers of the Helms Uprate will be much lower than PG&E claims.

Greater certainty of the actual ITC benefit for the combined Uprate and Lifecycle work is needed to determine if the project is cost-effective and is reasonable. The Commission should not approve PG&E's request for an up-front $462 million cost cap for the combined work until the IRS adopts the final guidelines and provides clarification that the Lifecycle work as well as the Uprate is eligible for the ITC. Moreover, PG&E's proposal to simply inform the Commission in a Tier 1 advice letter if the project yields less than the full 30% ITC credit without a demonstration that the project remains cost-effective is not reasonable and should be rejected due to the large magnitude of variability which will materially impact cost-effectiveness.

Cal Advocates discusses the impact of a lower ITC benefit on the cost-effectiveness of the Uprate in Chapter 2 of this testimony

C. Regulatory Uncertainty (Worhach)

PG&E admits that there are several regulatory processes which may impact the cost, scope, and schedule of the Helms Uprate and Lifecycle Replacement work.[55]

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[52] $15 million is calculated based on the lower uprate capacity of 150 MW: (150 MW / (1212 MW + 150 MW) times 30% times $450 million, which excludes the $12 million transmission upgrades that are ineligible for the ITC.

[53] Application at 14.

[54] Application at 14.

[55] Application at 12-13.

However, it is unclear if PG&E has sufficiently planned for how these approval processes will affect the cost and schedule of the project. PG&E indicates that costs that exceed the requested cost cap of $462 million may accrue due to the early stages and lack of detailed information related to these regulatory approval processes.[56] In addition, PG&E indicates that there may be environmental review required that it does not account for.[57] As detailed in the following sections, regulatory uncertainty is a significant concern that PG&E does not sufficiently address in its project plan. The Commission should not approve the Uprate and Lifecycle work until the regulatory processes have matured and until PG&E can provide greater certainty in the timelines and costs of the processes.

1. PG&E does not sufficiently plan for CEQA review

PG&E asserts that a Commission-led CEQA review of the Helms Uprate is not required[58] because FERC has "exclusive jurisdiction over the need determination, siting, construction, operation, and maintenance of hydroelectric pumped storage."[59] As such, the Application does not factor CEQA review into its timeline or budget.

However, whether CEQA applies is a legal issue for the Commission to determine in its review of the Application. Moreover, PG&E acknowledges that upgrades at the Gregg Substation could trigger a Commission-led CEQA review if substation upgrades are required by the CAISO.[60]

Despite these acknowledgements, PG&E continues to argue that it is reasonable to assume that no CEQA review will occur, reasoning broadly: "[S]ince the detailed design of the Helms Uprate Project is not yet complete, environmental review is not possible."[61] In a similar vein, PG&E dismisses the possibility that Gregg Substation upgrades could trigger a CEQA review: "[I]t is not possible at this time to study any changes to the

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[56] Application at 12-13.

[57] Application at 27, Footnote 38.

[58] Application at 29.

[59] Application at 29-30.

[60] Application at 27, Footnote 38.

[61] Application at 32.

Gregg Substation pursuant to the California Environmental Quality Act ("CEQA") because it would be entirely speculative to determine what, if any, changes to the substation will be needed."[62] PG&E's claims do not justify its exclusion of a plan for CEQA review but instead illustrate the speculative and premature nature of the Application. By PG&E's own admission, a CEQA review may be required, which would impact the project's budget and timeline. This belies the assertion that a CEQA review is unnecessary and makes it difficult for the Commission to make an informed determination as to whether elements of the Application are just and reasonable.

The Commission should therefore disregard PG&E's assertion that a CEQA review is unnecessary. By PG&E's own admission, there are several scenarios by which a CEQA review may still take place. Any CEQA review could increase project costs and timeline, which could impact the cost-effectiveness of the Uprate. The uncertainty about costs and timeline related to potentially necessary CEQA review demonstrate the speculative nature of the Application and illustrate why the Commission should require PG&E to perform further design work and allow regulatory processes to mature before granting PG&E's cost recovery request.

2. The timeline and outcome of the FERC relicensing process is uncertain

There is also regulatory uncertainty related to the ongoing FERC processes to relicense Helms and amend Helms' FERC license to account for the Uprate. PG&E states that it must apply for an amendment to its FERC license to perform the Helms Uprate work.[63] There are two possible FERC approaches to licensing the uprated capacity. PG&E states that the Uprate is "likely" to be eligible for a non-capacity amendment process, which is simpler and faster than a capacity amendment.[64] PG&E submitted its draft non-capacity license amendment in June 2024.[65] However, PG&E

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[62] Application at 27, Footnote 38.

[63] Application at 12.

[64] PG&E Testimony at 2-9.

[65] Attachment 4, PG&E Response to Cal Advocates Data Request 002, Question 4, at 1.

acknowledges that if it is unable to use the pending non-capacity amendment process, it will be forced to pursue a lengthier and more onerous licensing process, which can add 12-24 months to the project timeline and increase costs by up to $1 million.[66]

Moreover, there is additional FERC-related uncertainty that may impact Helms. PG&E's existing license to operate Helms expires in two years, and PG&E is in the process of relicensing the facility before FERC.[67] PG&E acknowledges that FERC is likely to impose new terms and conditions upon the operation of Helms as part of the relicensing, which will impact its operation for the next 50 years.[68] For example, PG&E has said elsewhere that regulatory changes at the FERC have led to smaller quantities of water being allocated to hydropower.[69] If that trend extends to the Helms relicensing, it would mean less water for energy generation and therefore a lower cost-effectiveness for the uprate due to lower energy revenues.

Because the FERC relicensing is ongoing, the potential impact is unknown. Regulatory requirements at FERC could increase costs by an estimated $1 million, delay the project delivery by 12-24 months, and decrease the amount of water available for energy generation, all of which would reduce the cost-effectiveness of the Helms Uprate, as discussed in Chapter 2. Considering these uncertainties, the Commission should require PG&E to further study the impact of the FERC licensing and provide more precise estimates to inform the Commission's decision on the reasonableness of the cost recovery sought.

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[66] Attachment 5, PG&E Response to Cal Advocates Data Request 001, Question 23, at 1-2.

[67] Attachment 6, PG&E Response to Cal Advocates Data Request 006, Question 3, at 1-2.

[68] Attachment 7, PG&E Response to Cal Advocates Data Request 001, Question 16.d, at 2-3.

[69] "For the 2022 IRP, PG&E modified 15-year historical average hydroelectric generation conditions to account for the future impacts of climate change and FERC relicensing. This assumption reflects lower generation than the 30-year historic average used in PG&E's 2020 IRP filing. A summary of these changes include… Expected FERC license conditions which result in less water allocated to hydroelectric generation." *2022 Integrated Resource Plan* at 62, Pacific Gas and Electric. Available at https://www.pge.com/assets/pge/docs/about/doing-business-with-pge/2022-PGE-Integrated-Resource-Plan.pdf.

D. PG&E Fails to Provide a Sufficiently Detailed Cost Estimate and Cost Contingencies to Support its Request for a Maximum Cost Cap (Peterson)

PG&E requests approval of a $462 million cost cap, which includes $308 million for expected costs[70] and a 50% contingency, or $154 million, to cover all potential risks and cost estimate uncertainties.[71] PG&E uses an AACE Class 5 cost estimate as the basis for its request in the Application for a budget authorization for the Helms Uprate project. PG&E has not demonstrated that its cost estimate and proposed cost contingencies are reasonable. PG&E's earliest-stage scoping and lack of detailed design do not support establishing a maximum cost cap of $462 million.

1. Background – AACE cost estimate classes

AACE International Recommended Practice No. 69R-12 provides a cost estimate classification system for the hydropower industry as a framework for cost estimating and budgeting. It defines five estimate classes based on the maturity level of the project, with Class 5 corresponding to the lowest maturity level (i.e. the earliest stages of the project) and Class 1 the highest maturity level. For each class, AACE describes the typical end usage, methodology, and expected accuracy range. As the maturity of a project progresses from a 0% to 100% project definition, the expected accuracy range narrows, and the typical end uses progress from screening to detailed budgeting.[72]

A Class 5 estimate is "generally prepared based on very limited information"[73] at a very early project stage (0-2% project definition).[74] Class 5 estimates have a very large expected accuracy range; the actual costs could be 20-50% lower or 30-100% higher than the base Class 5 estimate. A Class 5 estimate is not expected to be accurate – it is simply

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[70] Attachment 8, PG&E Response to Cal Advocates Data Request 003, Question 9, at 1.

[71] Attachment 9, Utility Standard PM-1015S: Project Cost Management Standard, at 17.

[72] Attachment 10, AACE International Recommended Practice No. 69R-12, Table 1, at 3.

[73] Attachment 10, AACE International Recommended Practice No. 69R-12, Table 2a, at 7.

[74] Attachment 10, AACE International Recommended Practice No. 69R-12, Table 1, at 3.

a "rough order of magnitude"[75] estimate. For that reason, the appropriate use of a Class 5 estimate is limited to strategic business planning purposes such as concept screening.[76]

A Class 3 estimate is prepared at a later stage than a Class 5 estimate, once the project has reached 10-40% project definition. A Class 3 estimate has a narrower expected accuracy range than a Class 5 estimate; the actual costs could be 10-20% lower or 10-30% higher than the estimated costs. In other words, the project is more mature, and thus the costs are more certain. Consequently, a Class 3 cost estimate is intended for end uses requiring a higher level of certainty, such as "budget authorization, appropriation, and/or funding."[77]

a. Use of a Class 5 estimate for budget authorization is inappropriate

PG&E requests approval of a $462 million cost cap, which includes $308 million for expected costs[78] and a 50% contingency, or $154 million, to cover all potential risks and cost estimate uncertainties.[79] PG&E's request for a $462 million cost cap is a request for budget authorization from the Commission. As explained in the prior section, the AACE International Recommended Practice No. 69R-12 makes clear that budget authorization is not an appropriate usage of a Class 5 estimate. Rather, budget authorization should be based upon usage of a Class 3 estimate.[80]

Planning for the combined Uprate and Lifecycle Replacement work is still in an early conceptual stage,[81] such that the actual costs may end up exceeding PG&E's 50%

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[75] See https://www.vistaprojects.com/construction-cost-estimate-classes/.

[76] Attachment 10, AACE International Recommended Practice No. 69R-12, Table 1 and Table 2a, at 3, 7.

[77] Attachment 10, AACE International Recommended Practice No. 69R-12, Table 2c, at 9.

[78] Attachment 8, PG&E Response to Cal Advocates Data Request 003, Question 9, at 1.

[79] Attachment 9, Utility Standard PM-1015S: Project Cost Management Standard, at 17.

[80] Attachment 10, AACE International Recommended Practice No. 69R-12, Table 2c, at 9.

[81] Attachment 10, AACE International Recommended Practice No. 69R-12, Table 1 and Table 2a, at 3, 7. A Class 5 cost estimate (such as that used in PG&E's Application) corresponds to 0 to 2% of full project definition. A Class 5 Estimate may be referred to as a "conceptual level estimate."

contingency.[82] Precisely for that reason, it is premature to approve cost recovery without further reasonableness review. While PG&E is correct that a 50% contingency would fall within the expected accuracy range for an AACE Class 5 cost estimate, PG&E errs in using a Class 5 cost estimate for budget authorization rather than a Class 3 estimate as specified in the AACE standard.

Moreover, PG&E's Project Cost Management Standard requires "a Class 3 estimate, at a minimum … for authorization by the PG&E Board of Directors."[83] In A.23-12-014, PG&E is seeking authorization for cost recovery at a project stage that is premature relative to the AACE International Recommended Practice and PG&E's own internal standard. In so doing, PG&E requests that the Commission impose a level of uncertainty on ratepayers that is deemed unacceptable by its own Board of Directors.

b. PG&E misuses the concept of contingency

Contingency allowances are intended to cover "unforeseen conditions."[84] However, PG&E's contingency covers both unforeseen conditions and uncertainty and unknowns in design and cost estimates.[85] The high amount of uncertainty in the cost estimate for the Helms Uprate is due largely to the prematurity of the project. PG&E justifies a 50% contingency by stating that "A 50% total contingency is within the recommended percentage range for Class 5 AACE Estimate Uncertainty,"[86] thereby arguing that, because a Class 5 cost estimate has a wide accuracy range, a high contingency is appropriate. While it is true that a less mature project has a wider accuracy range, it does not follow that the less mature a project is, the more money

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[82] Attachment 10, AACE International Recommended Practice No. 69R-12, Table 1, at 3. The expected accuracy range for a Class 5 cost estimate is -20% to -50% at the low end and +30% to +100% at the high end.

[83] Attachment 9, Utility Standard PM-1015S: Project Cost Management Standard, at 29.

[84] D.24-03-042 at 25: "…[C]ontingency allowances are intended to cover 'unforeseen conditions,' these amounts are also unpredictable, and therefore, the utility has not established these costs to be reasonable."

[85] Attachment 9, Utility Standard PM-1015S: Project Cost Management Standard, at 17: Contingency includes Weighted/Expected Value of AACE Estimate Uncertainty and Weighted/ Expected Value of Risks.

[86] Attachment 11, PG&E Response to Cal Advocates Data Request 003, Question 14, at 1.

should be approved for it. PG&E should not be shielded from the uncertainty inherent in its minimal level of project planning and project unknowns. The Application fundamentally misinterprets the purpose of a contingency. There is a crucial difference between unforeseen and undecided - between budgeting for the risk that certain unforeseen circumstances may arise versus budgeting more money to compensate for the fact that the design has not yet been developed.[87] Only the former is the intended purpose of a contingency and the latter should not be borne by ratepayers.

c. Contingencies are inherently speculative

Contingencies are inherently speculative and are meant to cover the costs of unforeseeable events.[88] As TURN argues in proceeding A.16-09-001, "While it is possible to retrospectively ascertain if the contingency was used prudently, there is not enough information at this time for the Commission to determine whether the requested costs are reasonable or will be spent reasonably."[89] PG&E is unable to demonstrate at this premature stage how it will spend its requested $154 million contingency - i.e. which specific activities or items those dollars will be allocated towards. The Application does not specify what portion or percentage of the contingency is meant to cover design, construction, regulatory delay, or commercial considerations. Without any information specifying how the requested $154 million will be used, the Commission cannot make a reasonableness determination. The Commission should reject any contingency that would have the practical effect of circumventing a reasonableness review of any part of the requested $154 million.

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[87] Draft tube modifications may follow a design in line with Hitachi's Plan A or Hitachi's Plan B. The latter involves significantly higher costs and is described by Stantec as uneconomical.

[88] Attachment 12, PG&E Response to Cal Advocates Data Request 003, Question 10.c, at 1. "Weighted/Expected Value of Risk is the total sum of expected risk value times the probability of the risk occurring for each identified risk."

[89] Opening Brief of The Utility Reform Network, A.16-09-001 at 145.

E. PGE's Proposed Plan Includes Significant Design and Performance Uncertainty (Peterson)

PG&E claims that the proposed Helms Uprate would increase the Helms nameplate generation capacity by 150-180 MW,[90] or 129-156 MW at the point of interconnection,[91] while the Helms pumping capacity would be increased by 0-78 MW.[92] The incremental capacity that would be realized by the Helms Uprate is uncertain because PG&E has not finalized turbine and draft tube designs, the model used to calculate maximum turbine output estimates is potentially inaccurate, and estimates and explanations provided by PG&E and its consultants are inconsistent and conflicting. The following sections provide Cal Advocates' analysis of the key factors that PG&E and its outside experts use to estimate the uprate capacity and identify the sources of the underlying uncertainties in PG&E's estimate.

1. Background

a. Net head determines maximum plant turbine output

Net hydraulic head ("net head") is equal to gross hydraulic head ("gross head") minus head losses due to friction. Hydraulic head is a value that measures the amount of mechanical energy available in water. In a hydroelectric facility such as Helms, hydraulic head is a function of the elevation difference between the upper and lower reservoirs.[93] Head losses are impacted by the flow rate of the water and the number of units in operation. Hydraulic head can be expressed in feet and is greatest when the upper reservoir is at its maximum volume and the lower reservoir is at its minimum volume (maximum gross head or "Hmax"). Helms has an Hmax of 1,744 feet.[94] Stantec estimates net head at Hmax and maximum plant turbine output (corresponding to three-

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[90] PG&E Testimony at 1-1.

[91] Attachment 13, PG&E Response to Cal Advocates Data Request 001, Question 29, at 1.

[92] Attachment 13, PG&E Response to Cal Advocates Data Request 001, Question 29, at 1.

[93] See https://energyeducation.ca/encyclopedia/Hydraulic_head.

[94] Attachment 39, Stantec Draft Report on Engineering Assessment for the Uprate of Helms Pumped Storage Plant, at 8-9 (Public Version).

unit operation and a high flow rate) to be 1,700 feet for the existing design and 1,690 feet for the uprated design.[95] Conversely, hydraulic head is at its lowest when the upper reservoir is at its minimum volume and the lower reservoir is at its maximum volume (minimum gross head or Hmin). The amount of power a pumped hydro facility is capable of generating (or consuming while pumping) varies depending on hydraulic head.

b. PG&E's capacity definitions

Incremental capacity is the difference between uprated capacity and current capacity, each of which can refer to a rated power or a maximum power output under a given set of conditions. PG&E acknowledges that "There are many ways to calculate rated power in different contexts and for different regulators."[96] PG&E defines the current nameplate capacity of Helms as 1,212 MW, or 404 MW per unit, based on the generator nameplate ratings.[97] PG&E compares the estimated uprated capacity range to derive its incremental capacity range based on the current nameplate capacity. Helms is capable of generating at nameplate capacity over a wide range of gross heads – from 1744 feet to 1600 feet or less.[98] Nameplate capacity is distinct from the maximum total power output for Helms, which is currently 1,218 MW generator output.[99] Maximum turbine output is not measured but can be estimated from generator output. Assuming 0.98 generator efficiency, a generator output of 1,218 MW corresponds to an estimated turbine output of about 1,243 MW.[100]

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[95] Attachment 40, Stantec Analysis of Alternatives Helms Uprate, at 23 and 25 (Public Version): The uprated design would allow for increased flow rate, which would increase head losses.

[96] Attachment 14, PG&E Response to CPUC Data Request 002, Question 5, Footnote 2, at 1.

[97] Attachment 14, PG&E Response to CPUC Data Request 002, Question 5, at 1: "The existing units are rated 404 MW each based on the generator nameplate rating of 448.5 megavolt-ampere (MVA). 404 MW is calculated by multiplying the generator MVA rating by 0.9 power factor (448.5 MVA * 0.9 power factor = 403.65 MW = 404 MW (rounded))."

[98] Attachment 15, PG&E Response to Cal Advocates Data Request 013, Question 11.e, at 3.

[99] Attachment 16, PG&E Response to Cal Advocates Data Request 013, Question 2, at 1.

[100] Attachment 17, PG&E Response to Cal Advocates Data Request 013, Question 6, at 1.

PG&E estimates the uprated turbine capacity based on maximum gross head.[101] PG&E anticipates the uprated nameplate capacity of Helms to be 1,392 MW, or 464 MW per unit[102] (180 MW greater than the current nameplate capacity). If the uprated turbines are capable of generating enough power to operate the generators at 464 MW each (about 473 MW per turbine), then the uprated maximum total power output for Helms would also be 1,392 MW (174 MW greater than the current maximum total power output).[103] As explained below, it is highly uncertain whether each of the uprated turbines will be capable of reaching 473 MW.

2. PG&E's draft tube options are based on an uneconomical design

PG&E explains that the draft tube design will not be finalized until the turbine design is selected.[104] The uprated turbine capacity is dependent on the turbine design and draft tube design and will be determined and validated through physical model testing.[105,106] PG&E has not yet selected the turbine design, and the selected final design may not maximize capacity, due to other considerations such as maximum efficiency point and minimum output.[107]

Hitachi Ltd., the original equipment manufacturer of the existing Helms turbines, prepared a preliminary analysis of potential turbine uprates for PG&E in 2022 (Hitachi Turbine Study).[108] The Hitachi Turbine Study assessed two design options for

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[101] Attachment 15, PG&E Response to Cal Advocates Data Request 013, Question 11.e, at 3.

[102] Attachment 15, PG&E Response to Cal Advocates Data Request 013, Question 11.c, at 2.

[103] Attachment 15, PG&E Response to Cal Advocates Data Request 013, Question 11.c, at 2.

[104] Attachment 18, PG&E Response to Cal Advocates Data Request 005, Question 6, at 1.

[105] Attachment 19, PG&E Response to Cal Advocates Data Request 005, Question 4, at 2: "Ultimately the uprated turbine performance will be determined and validated during physical model testing."

[106] Attachment 20, PG&E Response to Cal Advocates Data Request 005, Question 10.d, at 2: "actual values at high, normal, and minimum head will be determined once a turbine design is selected and physical model testing is performed."

[107] Attachment 39, Stantec Draft Report on Engineering Assessment for the Uprate of Helms Pumped Storage Plant, at 19 (Public Version).

[108] PG&E Testimony, Attachment A, Hitachi Turbine Study, October 17, 2022.

draft tube modifications: Plan A and Plan B. The extent of the modifications required for Plan B is significantly greater than that of Plan A. Whereas Plan A requires "relatively little intervention," Plan B involves "substantial draft tube modifications which would involve heavy civil work and replacement of the entire draft tube."[109] The Hitachi Turbine Study estimates maximum turbine output at 1,744 feet net head to be 455 MW for Plan A and 463 MW for Plan B.[110] Stantec's Analysis of Alternatives concludes that a design similar to Hitachi's Plan B would be uneconomical and therefore assumes a design similar to Hitachi's Plan A in its calculations.[111]

3. PG&Es uprated capacity estimates are inconsistent and uncertain

While PG&E consistently calculates incremental capacity based on a current capacity of 1,212 MW, the basis for PG&E's estimated uprated capacity range is less clear. In PG&E's Response to Cal Advocates Data Request 001, Question 12, PG&E acknowledges its "inability to guarantee a certain MW increase at this stage of the project."[112] In PG&E Response to Cal Advocates Data Request 001, Question 29, PG&E appears to claim that the uprated capacity range is bookended by Hitachi's Plan A and Plan B, stating, "The generation increase was based on a Hitachi study that indicated a range of nameplate generation increase of 51 - 59 MW per unit, or 153 - 177 MW for the facility (or approximately rounded to 150-180 MW)."[113] The Hitachi Turbine Study identified two potential designs for draft tube modifications: Plan A and Plan B, which Hitachi estimated would result in 455 and 463 MW maximum turbine output. These

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[109] Attachment 39, Stantec Draft Report on Engineering Assessment for the Uprate of Helms Pumped Storage Plant, at 11 (Public Version): "Plan A would require relatively little intervention to the existing unit and civil works, with only the upper portion (the first approximately 1.5 m) of the upper draft tube and discharge ring requiring modifications… Plan B modifications would involve the enlarged runner throat as well as substantial draft tube modifications which would involve heavy civil work and replacement of the entire draft tube."

[110] PG&E Testimony, Attachment A Hitachi Turbine Study at 2-AtchA-4, Fig 3-6.

[111] Attachment 40, Stantec Analysis of Alternatives Helms Uprate, at 51 (Public Version).

[112] Attachment 21, PG&E Response to Cal Advocates Data Request 001, Question 12, Attachment 1, Question 5, at 2.

[113] Attachment 13, PG&E Response to Cal Advocates Data Request 001, Question 29, at 1.

values are 51 and 59 MW greater than the current nameplate generator output of each unit, or 153 and 177 MW if multiplied by three to reflect the three units at the Helms facility, apparently serving as the bookends for the nameplate generation increase cited above.[114] However, the maximum output identified in the Hitachi Turbine Study refers to uprated turbine output at a net head of 1,744 feet[115] and therefore should not be compared to current generator output – both because turbine output and generator output are not equivalent and because 1,744 feet net head is outside the operating range at Helms.[116] Additionally, PG&E has repeatedly framed the model used in Hitachi's calculations as inaccurate.[117],[118]

In PG&E's response to Cal Advocates Data Request 013, PG&E offers a different explanation for its incremental capacity range. In this response, PG&E states that the 150-180 MW incremental capacity range is not rounded from Hitachi's estimate of 153-177 MW. Rather, the lower bookend value of 150 MW is based on the Hitachi Turbine Study's estimated maximum uprated turbine outputs of 455 and 463 MW, corresponding to generator outputs of 446 and 454 MW generator output, respectively.[119] PG&E chooses the higher of these values as the low end of its estimated incremental capacity range. 454 MW is 50 MW greater than the current generator nameplate capacity, or 150 MW for the facility. However, the 463 MW turbine output in the

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[114] 455 – 404 = 51; 51 x 3 = 153; 463 – 404 = 59; 59 x 3 = 177.

[115] PG&E Testimony, Attachment A Hitachi Turbine Study at 2-AtchA-4, Fig 3-6.

[116] The maximum gross head at Helms is 1,744 feet. In operation, net head will always be less than gross head due to losses.

[117] Attachment 19, PG&E Response to Cal Advocates Data Request 005, Question 4, at 1-2: "[Hitachi's] model is extrapolated from the analytical model of the existing turbine that underestimates the actual output of existing 404 MW generator unit both at high and normal net head."

[118] Attachment 22, PG&E response to Cal Advocates Data Request 013, Question 12, at 2: "Hitachi's Model underestimates the performance of the existing Helms Units in two ways. One, it does not align with Helms existing unit performance at rated head (371 MW vs 404 MW). Two, it assumes a larger guide vane opening than what is required for the existing units to achieve 404 MW, which means the Hitachi model requires more flow through the unit to achieve 404 MW."

[119] Attachment 23, PG&E response to Cal Advocates Data Request 013, Question 11.a, at 2.

Hitachi Study is based on the Plan B design for draft tube modifications,[120] which Stantec determines to be uneconomical.[121]

In PG&E's response to Cal Advocates Data Request 013, PG&E claims that the upper bookend value of 180 MW is based on an evaluation of the Unit 2 generator which indicated that it is capable of operating at 464 MW.[122] 464 MW is 60 MW greater than the current generator nameplate capacity, or 180 MW for the facility. To support this value, PG&E cites to two studies: the Black and Veatch Feasibility Study and the Stantec Analysis of Alternatives, each of which conflates maximum turbine output and maximum generator output, estimating both to be 460 MW.[123,124] These two studies are based on Hitachi's model, which PG&E describes as conservative. Instead of adopting 460 MW as the upper bookend value for its estimated incremental capacity range, PG&E assumes that the uprated capacity would be limited by the generator rather than the turbine and adopts the Unit 2 operating limit of 464 MW (corresponding to 473 MW turbine output per unit).[125]

Using Hitachi's model, and considering head losses, Stantec estimates that the maximum generator output at maximum head would be 1,309 MW,[126] or just 97 MW more than the current nameplate capacity. In the same study, Stantec estimates that maximum turbine power output could be 450-460 MW,[127] corresponding to 111-140 MW incremental generation capacity. Also in the same study, Stantec deems that maximum

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[120] PG&E Testimony, Attachment A Hitachi Turbine Study at 2-AtchA-4, Fig 3-6.

[121] Attachment 40, Stantec Analysis of Alternatives Helms Uprate, at 51 (Public Version).

[122] Attachment 23, PG&E response to Cal Advocates Data Request 013, Question 11.c, at 2.

[123] PG&E Testimony, Chapter 2, Attachment E Black and Veatch Feasibility Study: Figure 2-10 refers to a maximum turbine output of 459 MW; Table 2-2 refers to unit output as 459 MW, apparently referring to generator output.

[124] Attachment 40, Stantec Analysis of Alternatives Helms Uprate, at 1, 40, and 50: Stantec refers to "460 MW per unit (generator output)" at 12 (Public Version). Stantec refers to 450-460 MW turbine output multiple times.

[125] Attachment 23, PG&E response to Cal Advocates Data Request 013, Question 11.c, at 2.

[126] Attachment 40, Stantec Analysis of Alternatives Helms Uprate, at 25 (Public Version).

[127] Attachment 40, Stantec Analysis of Alternatives Helms Uprate, at 49 (Public Version).

generation output of 460 MW is feasible,[128] corresponding to 168 MW incremental generation capacity.

PG&E claims that the Hitachi model underestimates turbine output, stating that "PG&E believes that Hitachi's model result of 463 MW (Turbine) may be lower than what could be achieved with modern design since their model is extrapolated from the analytical model of the existing turbine that underestimates the actual output of existing 404 MW generator unit both at high and normal net head."[129] The outside consultant studies (Hitachi Turbine Study, Black and Veatch, Stantec Analysis of Alternatives) each base their estimates on Hitachi's model.[130] Until physical model testing has been performed, there is no alternative basis from which to derive a more accurate estimate. PG&E has made its own uncertain estimates to compensate for the supposed underestimation of the uprate capacity by the Hitachi model. By using turbine capacities at an infeasibly high net head value,[131] and selecting the turbine capacity for an uneconomical design option,[132] and selectively choosing only the highest values provided by consultants,[133] then adding an arbitrary additional four megawatts per unit,[134] PG&E inflates what it claims to be an originally conservative uprate value. While these measures may offset any potential underestimation in the Hitachi model, that is not an indication that the resulting estimate is more accurate. Overall, reliance on Hitachi's model, Black and Veatch's and Stantec's conflation of turbine and generation outputs,

[128] Attachment 40, Stantec Analysis of Alternatives Helms Uprate, at 12 (Public Version).

[129] Attachment 19, PG&E Response to Cal Advocates Data Request 005, Question 4, at 1-2

[130] Attachment 23, PG&E response to Cal Advocates Data Request 013, Question 11.c, at 2.

[131] Hitachi's estimates are for an infeasible net head of 1,744 feet.

[132] 463 MW turbine output corresponds to the Hitachi Plan B design for draft tube modifications, which Stantec determines is uneconomical.

[133] Stantec provides conflicting estimates in its Analysis of Alternatives, including: 1,309 MW plant generation output (97 MW incremental capacity), 450-460 MW turbine output (111-140 MW incremental capacity), and 460 MW generator output (168 MW incremental capacity). PG&E cites 460 MW generator output.

[134] PG&E explains that while Black and Veatch and Stantec estimate that up to 460 MW generator output is possible, PG&E believes 464 MW generator output is possible on the basis that the Hitachi model underestimates capacity.

and PG&E's shifting explanations contribute to a large amount of uncertainty in the amount of incremental capacity the Helms uprate would achieve.

F. The Schedule and Costs of CAISO Interconnection are Uncertain, and the Date for FCDS and RA Value is Unknown (Peterson)

1. CAISO Interconnection schedule is uncertain

In the Application and testimony filed on December 23, 2023, PG&E asserted that the target online dates for the uprated Helms units would be 2029-2031,[135] assuming Commission approval of the Application in 2025[136] and eligibility in the CAISO Cluster 15 interconnection study process.[137] PG&E's timeline assumes completion of CAISO interconnection study in 2026, with CAISO interconnection work carried out in 2026-2029.[138] PG&E concluded that the Helms Uprate would achieve FCDS eligibility and be able to earn RA value by the end of the year 2030.[139]

However, since the Application was filed, CAISO's interconnection study process has evolved, with significant implications for the proposed Helms Uprate project's schedule, FCDS, and RA value. CAISO has adopted new rules that, among other changes, render a project ineligible for interconnection study if its POI is behind one or more transmission constraints with zero TPD.[140] Based on CAISO's Zonal TPD Constraint Mapping, Helms' POI at the Gregg substation is behind multiple transmission constraints, of which four have zero TPD available.[141] As a result of the zero TPD constraints, PG&E states the Helms uprate project is ineligible for the current Cluster 15 Interconnection study process.[142]

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[135] PG&E Testimony at 2-1.

[136] PG&E Testimony at 2-15.

[137] PG&E Testimony at 2-4.

[138] PG&E Testimony at 2-16.

[139] PG&E Testimony at 2-1.

[140] PG&E Supplemental Testimony at 4.

[141] PG&E Supplemental Testimony at 7.

[142] PG&E Supplemental Testimony at 4.

PG&E will therefore need to apply for interconnection study again in Cluster 16, which at the earliest opens in October 2026.[143] A delay from Cluster 15 to Cluster 16 represents a 2-year delay in the interconnection process, which would result in a 2-year delay in interconnection work and potentially delay the overall project schedule. However, the eligibility of the Helms Uprate for Cluster 16 represents a best-case scenario and is not guaranteed. If the Uprate again fails to be eligible for the next cluster study process, the result would be one or more additional years of delay in the interconnection process. While the updated project timeline in PG&E's supplemental timeline reflects the ineligibility of the Helms Uprate project for Cluster 15 interconnection study as a 2-year delay in interconnection work, it does not show any delay to construction work or commercial online date.[144] PG&E states that the "target" construction timeline is unchanged, but PG&E does not provide any evidence that the realized construction schedule will not be delayed.[145] PG&E's revised timeline now assumes Commission approval prior to the Uprate's eligibility for the CAISO interconnection study process, well before there will be any information about the Uprate's FCDS or RA eligibility status. PG&E's Supplemental testimony succeeds only to compound the multiple uncertainties present in the Application.

For the Helms Uprate to be eligible for an interconnection study, the four transmission constraints with zero TPD must be resolved and adequate TPD must be allocated to the Helms Uprate project.[146] Resolution of those transmission constraints requires CAISO approval of three transmission upgrade projects (Three Transmission

[143] PG&E Supplemental Testimony at 8.

[144] PG&E Supplemental Testimony at 12.

[145] PG&E Supplemental Testimony at 11.

[146] Attachment 24, PG&E Response to Cal Advocates Data Request 012, Question 3, at 1: "One thing that could prevent the Helms Uprate from being eligible for Cluster 16, even if the Three Transmission Projects are approved, is if the added TPD is fully allocated to existing CAISO Queue projects through the annual TPD allocation process prior to Cluster 16. This is why PG&E has indicated that it believes TPD will need to be reserved for the Helms Uprate project to be eligible."

Projects), which is uncertain.[147] The Three Transmission projects must be approved in either the 2024-2025 or 2025-2026 Transmission Planning Process (TPP) for the Helms Uprate to be eligible for study in Cluster 16. The Three Transmission Projects were previously considered in the 2023-2024 TPP but not approved,[148] despite a backlog of more than 4,500 MW of Cluster 14 and earlier projects in the Fresno Local area that were seeking the same TPD as Helms.[149] Even if all three transmission projects are approved in the 2024-2025 or 2025-2026 TPP, the Helms Uprate would compete with other projects for the TPD in CAISO's annual allocation process. Therefore, PG&E intends to request that CAISO reserve TPD capacity for the Helms Uprate.[150] However, until CAISO makes a final determination on whether to award the reserved capacity to the Uprate, the timing and amount of FCDS capacity and RA value will remain uncertain.

PG&E anticipates that the longest of the Three Transmission Projects will take 15 years to complete, with an earliest in-service date of 2040, assuming the project is approved in the 2024-2025 TPP.[151] Until then, the Helms Uprate will not have FCDS,

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[147] PG&E Supplemental Testimony at 10: Gates Bank 500/230 kV Bank #13 (estimated project duration: 48 months); Le Grand 230 kV Station Conversion (estimated project duration: 180 months); and Reconductor Wilson-Storey 230 kV Lines (estimated project duration: 86 months). PG&E cites to CAISO's 2024 capability estimates for use in the CPUC's IRP process, available at: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.caiso.com%2Fdocuments%2Fattachment-a-transmission-capability-estimates-for-use-in-the-cpuc-irp-process-v2024.xlsx&wdOrigin=BROWSELINK

[148] The Three Transmission Projects were also included in CAISO's 2023 capability estimates for use in the CPUC's IRP process, available at: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.caiso.com%2FDocuments%2FTransmission-Capability-Estimates-for-use-in-the-CPUCs-Integrated-Resource-Planning-Process.xlsx&wdOrigin=BROWSELINK

[149] PG&E Supplemental Testimony at 8-9: "Multiple Gregg 230kV transmission constraints have 4.5+ gigawatts (GW) of new generation resources in the Cluster 14 or previous queue waiting for the constraints to be resolved."

[150] PG&E Supplemental Testimony at 9.

[151] PG&E Supplemental Testimony at 11.

without which it cannot provide RA capacity.[152] PG&E acknowledges that the Helms Uprate would operate as energy-only until it becomes eligible for RA.[153]

2. The interconnection costs and scope of work are uncertain

PG&E will not know what interconnection work, if any, is needed to support the Helms Uprate until the Uprate becomes eligible for an interconnection study process and the interconnection study is completed.[154] Any potential interconnection work cannot begin until the interconnection study is complete.[155] The potential interconnection work includes network upgrades and upgrades at the Gregg Substation.[156] PG&E excludes Network Upgrade costs from the Cost Recovery Cap because those costs are reimbursed by the Transmission Operator[157] through the FERC-approved Transmission Access Charge (TAC).[158] PG&E's cost forecast for the Helms Uprate includes $12.7 million for Interconnection costs – a "placeholder"[159] amount based on the cost of potentially replacing up to 6 circuit breakers and disconnect switches at the Gregg Substation or a

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[152] Except during construction, when the uprated units will be able to provide limited RA capacity. Unit 1 will provide RA when Unit 2 is offline, and Unit 1 and Unit 2 will provide RA when Unit 3 is offline.

[153] PG&E Supplemental Testimony at 16.

[154] Attachment 25, PG&E Response to TURN Data Request 003, Question 15, at 1: "The scope of work for interconnection will not be known until CAISO performs the interconnection study… It is unknown what potential upgrades and costs will be required for Gregg Substation and the greater grid. This information will be provided in the CAISO Interconnection Study."

[155] Attachment 26, PG&E Response to TURN Data Request 007, Question 3, at 2: "PG&E does not believe it can proceed with construction of interconnection upgrades prior to completion of the Interconnection Study."

[156] Attachment 27, PG&E Response to Cal Advocates Data Request 002, Question 3, Attachment 1, at 3: "PG&E Hydro is not aware of any Reliability Network Upgrades that are needed to interconnect Helms PSP Uprate project. It is unknown if this Independent Interconnection Study will result in identification of any Reliability Network Upgrades."

[157] PG&E Testimony at 2-4.

[158] Attachment 28, PG&E Response to TURN Data Request 003, Question 17, at 1: "the costs for Network Upgrades are recovered through FERC-approved transmission rates. As such, these costs are not included in the Cost Recovery Cap proposed in this application."

[159] PG&E Testimony at 2-4.

"similar level of work elsewhere on the grid," plus a 50% contingency.[160] PG&E requests that the Commission approve $8.5 million for unspecified work that may be needed, plus another $4.2 million in case PG&E has significantly underestimated the cost or extent of the potential work. PG&E requests that the Commission approve those costs now and upfront, before the scope of interconnection work is known, without any further reasonableness review and nothing more than an informational Tier 1 Advice Letter to inform the Commission of the actual interconnection costs.[161] The submission of the Application well before the completion of the CAISO Interconnection Study adds uncertainty regarding the scope of work included in the project and the associated time and costs.

G. PG&E Does Not Account for Climate Change Uncertainty Associated with Long-range Hydroelectric Planning (Worhach)

The Application does not address how climate change will impact the operation or value of Helms over the next 50 years. In response to data requests, PG&E states that Helms is a closed loop system and therefore relatively unaffected by water availability issues.[162] PG&E argues that because Helms is located off-river, and has a large storage capacity, it is relatively insulated from water shortages.[163] PG&E provided modeling showing that even in prolonged droughts of three to six years, it can manage the reservoirs such that Helms is still able to reach its peak capacity throughout the year.[164]

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[160] Attachment 29, PG&E Response to TURN Data Request 003, Question 15, at 1, emphasis added: "The scope of work for interconnection will not be known until CAISO performs the interconnection study. The $12.7 million included in the project is for a potential scope of work that could include replacement of up to 6 circuit breakers and associated disconnect switches within the Gregg Substation (or similar level of work elsewhere on the grid). An estimate of $1.125 million per circuit breaker / disconnect switch was used for a total of $6.750 million. Also included in the cost is $150,000 for the CAISO Study. A 2.5% annual escalation was then applied to the $6.9 million, followed by application of 50% contingency, bringing up the total to $12.7 million."

[161] PG&E Testimony at 2-4 – 2-5.

[162] Attachment 1, PG&E Response to Cal Advocates Data Request 001 Question 27 at 1; Attachment 30, PG&E Response to Cal Advocates Data Request 004 Question 3, at 1-2.

[163] Attachment 1, PG&E Response to Cal Advocates Data Request 001 Question 27 at 17; Attachment 30, PG&E Response to Cal Advocates Data Request 004 Question 3, at 1-2.

[164] Attachment 31, PG&E Supplemental Response to TURN DR 006 Question 9, at 1.

However, PG&E concedes that Helms will still be impacted by drought.[165] Although PG&E may be able to maintain full capacity at Helms via proactive water management, doing so in drought years will mean less total energy generation and therefore potentially lower energy market revenues.[166] Even if the decreased generation is likely to fall in lower value periods as PG&E claims,[167] any loss of energy generation revenue will reduce the value of the Helms Uprate if low hydro conditions prevail in the future.

H. There is Abundant time for PG&E to Develop a More Certain Design, Cost Estimate, Schedule, and Cost-effectiveness Analysis (Worhach)

Cal Advocates demonstrates in this testimony that more certain information for the Uprate and Lifecycle work, including engineering design and cost forecasts, ITC eligibility, CAISO and FERC regulatory processes, and CEQA review is necessary for the Commission to evaluate the reasonableness of PG&E's request for an up-front $462 million cost cap. PG&E likewise acknowledges that there is considerable uncertainty in its proposed plan.[168] Nonetheless, PG&E claims that that the Application must be approved "now … to take advantage of the [30%] Investment Tax Credit" codified in the IRA.[169] PG&E also claims that the Lifecycle Replacement work cannot be deferred for the purpose of awaiting regulatory approval of the Helms Uprate without creating significant reliability risks[170] and that achieving a final decision in the near term is critical to achieving the necessary online dates.[171]

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[165] Attachment 32, PG&E Response to Cal Advocates Data Request 001 Question 28, at 1.

[166] Attachment 1, PG&E Response to Cal Advocates Data Request 001 Question 27, at 1.

[167] Attachment 1, PG&E Response to Cal Advocates Data Request 001 Question 27, at 1.

[168] PG&E Testimony at 2-11.

[169] PG&E Testimony at 2-8, 2-13.

[170] Reply of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Protests to Application to Recover Helms Uprate Costs (PG&E Reply to Protests) at 5.

[171] PG&E Reply to Protests at 9.

However, PG&E's claim that there is an urgent need to approve the Helms Uprate and Lifecycle Replacement work is unsupported. Rather, as discussed in this section, there is sufficient time for PG&E to conduct detailed engineering studies and to develop more certain cost forecasts, as well as time for the FERC and CAISO regulatory processes to advance and yield more certain information, especially now that PG&E has acknowledged that there will be a two-year delay or longer in the CAISO interconnection study process.

PG&E asserts that its request to recover up to $462 million must be expeditiously approved[172] so that the Helms Uprate and Lifecycle Replacement work will: 1) begin construction by 2029 to qualify for the ITC; 2) maintain the reliable operation of the Helms facility; and 3) satisfy the Commission's order in D.21-16-035 to procure long-duration storage resources. These assertions are examined in the following sections.

1. Deadline to qualify for the Investment Tax Credit

PG&E urges the Commission to expeditiously approve an upfront maximum cost cap of $426 million to secure an ITC benefit for combined Helms Uprate.[173] PG&E asserts that waiting to further develop the project or to complete CAISO interconnection studies would jeopardize the project's eligibility for the ITC.[174]

However, as PG&E acknowledges, the construction deadline for ITC eligibility was extended to December 31, 2033 under the IRA.[175] This deadline was affirmed in the June 2, 2024 proposed guidance in Section 48E of the federal tax code.[176] The proposed guidance thus indicates that to be eligible for the ITC, construction of the Helms Uprate does not need to start until a full five years beyond PG&E's targeted construction start date. Given that the proposed rules have not yet been adopted, the projection of firm ITC

[172] PG&E Reply to Protests at 2.

[173] PG&E Testimony at 2-14.

[174] PG&E Testimony at 2-18.

[175] PG&E Testimony at 2-13.

[176] June 2, 2024 proposed U.S. Tax Code § 1.48E-1(c)(3) and § 1.45Y-1(c)(3). Available at: https://www.federalregister.gov/d/2024-11719/p-834 and https://www.federalregister.gov/d/2024-11719/p-68, respectively.

deadlines is inherently speculative. However, the record does not currently support PG&E's claim that there is an urgent need to approve its up-front proposed costs without further reasonableness review.

2. Timeline for Lifecycle Replacement work

PG&E claims that any delay in approval of the Application would delay Lifecycle Replacement work beyond the ten-year reliability timeframe and thereby risk unit outages.[177] However, PG&E states that if the Application is not resolved or is denied, it will pursue approval of the Lifecycle Replacement work in its 2027 GRC, which will be filed in 2025, two years after PG&E filed the Application.[178] Notwithstanding this two-year procedural delay, PG&E estimates that the Lifecycle Replacement work would take place between 2030-2032, one year beyond the schedule proposed for the combined Uprate and Lifecycle Replacement.[179]

PG&E's proposed construction schedule for the combined Uprate and Lifecycle project in 2029-2031 includes a three-year buffer to meet Lifecycle reliability needs in 2034. PG&E's alternative plan to conduct Lifecycle Replacement work alone has at least a two-year buffer. In either case, PG&E can initiate and complete a major portion the Lifecycle work within the ten-year lifecycle replacement timeframe that is also ahead of the December 31, 2033 construction start deadline for ITC eligibility. Therefore, PG&E has not demonstrated that there is a need to expeditiously approve the Helms Uprate or the Lifecycle Replacement work to meet reliability issues that obviates an adequate reasonableness review.

3. Timeline for procurement of long-duration storage

In its supplemental testimony, PG&E acknowledges that the incremental 150-180 MW capacity of the Helms Uprate project will not be eligible to meet PG&E's long-

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[177] PG&E Testimony at 2-8.

[178] PG&E Testimony at 4-2.

[179] PG&E Testimony at 2-5.

duration energy storage procurement obligation in D.21-06-035,[180] which PG&E originally invoked as authority for approval of the Application.[181]

PG&E admits that the Uprate will not qualify for long-duration energy storage under the Commission's existing IRP procurement order due to the 10-year or more delay to achieve FCDS.[182] The ineligibility of the Uprate for long-duration energy storage procurement under the IRP renders moot PG&E's request for authority under D. 23-02-040, D.22-02-004, and D.21-06-035 because the incremental long-duration storage capacity of the Uprate will not be fully deliverable by 2031 as required in the IRP decisions.[183]

Furthermore, it is unclear when, if ever, the Helms Uprate will qualify for any future long-duration energy storage procurement. Despite its acknowledgment that the Helms Uprate will not qualify for D.21-06-035 procurement, PG&E claims that the Helms Uprate could meet some yet to be determined Commission order for long duration storage after 2031.[184] In supplementary testimony, however, PG&E admits that the Uprate will not have FCDS at least until 2040, making the Uprate ineligible for Commission procurement orders before 2040.[185] In any case, the Commission should reject PG&E's request to approve the Application to meet some yet to be determined procurement order for long-duration storage that the Uprate may not be eligible to fill.

4. Cal Advocates' revised timeline

PG&E provided an initial estimate of the Helms Uprate and Lifecycle Replacement project timeline in the Application[186] which it subsequently updated on July 15, 2024 in response to discovery by TURN to incorporate a 9-11 month delay in the

[180] PG&E Supplemental Testimony at 20.

[181] D.21-06-035, Ordering Paragraph 2 at 94-95.

[182] PG&E Supplemental Testimony at 21.

[183] PG&E Supplemental Testimony at 21.

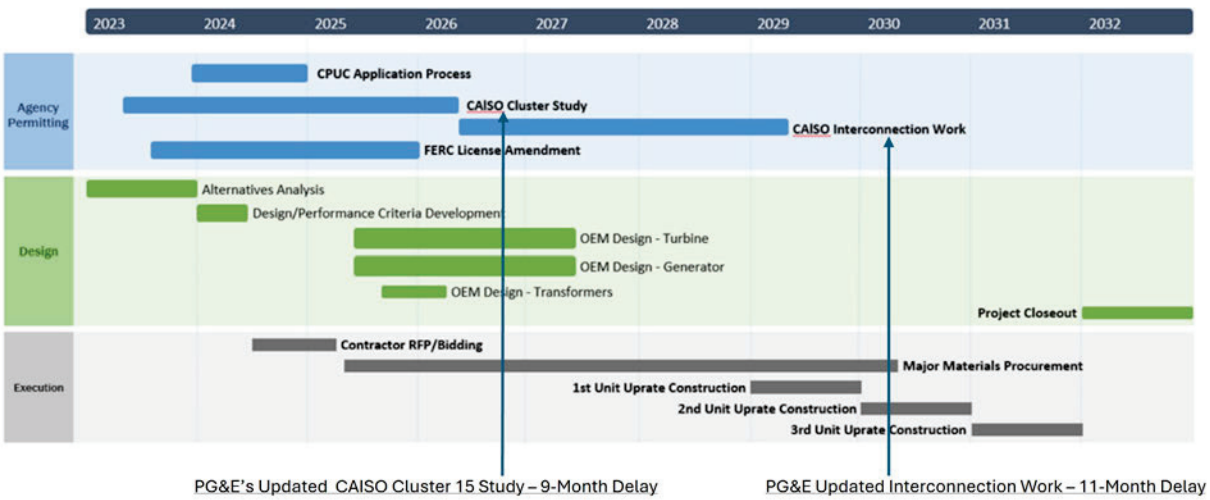
[184] Application at 5.

[185] PG&E Supplemental Testimony at 10 and 20.

[186] PG&E Testimony at 2-11.

completion of the CAISO Cluster 15 study process and the interconnection work.[187] PG&E updated the timeline again on September 30, 2024 in its Supplemental Testimony, reflecting interconnection delays corresponding the Uprate's ineligibility for study in the CAISO's Cluster 15 study process and its yet-to-be-determined eligibility for the Cluster 16 study process.[188] In Figures 1-1 and 1-2, Cal Advocates replicates PG&E's original revised timeline and the timeline submitted in the Supplemental Application.

Figure 1-1 PG&E's Original Helms Timeline with July 15, 2024 Revisions[189]



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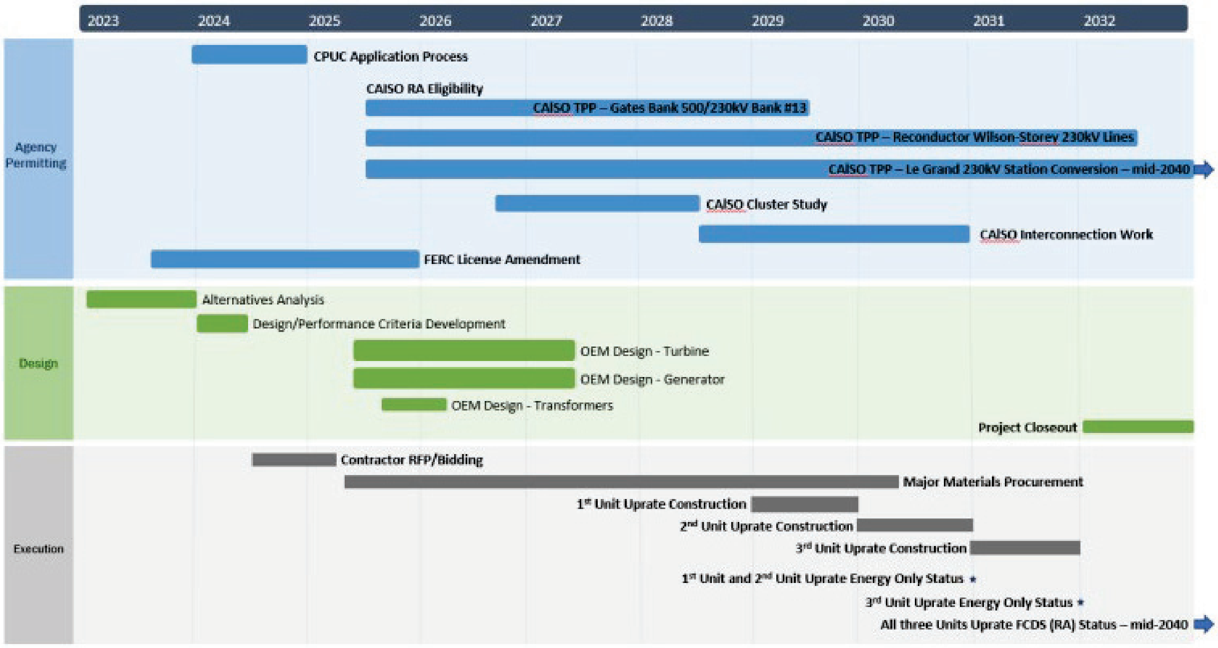
[187] Attachment 33, PG&E Response to TURN Data Request 008, Question 3, at 1.

[188] PG&E Supplemental Testimony at 12.

[189] PG&E Testimony at 2-16, with July 15, 2024 revisions provided in Attachment 33; Attachment 33, PG&E Response to TURN Data Request 008, Question 3, at 1.

Figure 1-2 PG&E's Supplemental Testimony Helms Uprate Timeline[190]



PG&E's timeline in Supplemental Testimony incorporates an additional delay of up to 24 months for the interconnection study and 8 months for the completion of interconnection work. Despite the interconnection study and interconnection work delays, PG&E continues to target a construction timeline of 2029, 2030, and 2031, which is unchanged from the original applications.[191] PG&E fails to provide evidence that the minimum 2-year delay in the CAISO interconnection process will not delay the construction timeline. Rather, PG&E's target could become a moving target, as is the case for the interconnection work.

Cal Advocates prepared a revised project timeline, shown in Figure 1-3, that illustrates the additional time available to maintain the Helms Uprate ITC eligibility and begin the Lifecycle Replacement work. Under this revised timeline, the Helms Uprate will be eligible for the ITC if construction begins before December 31, 2033 and the Lifecycle Replacement work will be underway to meet reliability needs. PG&E's

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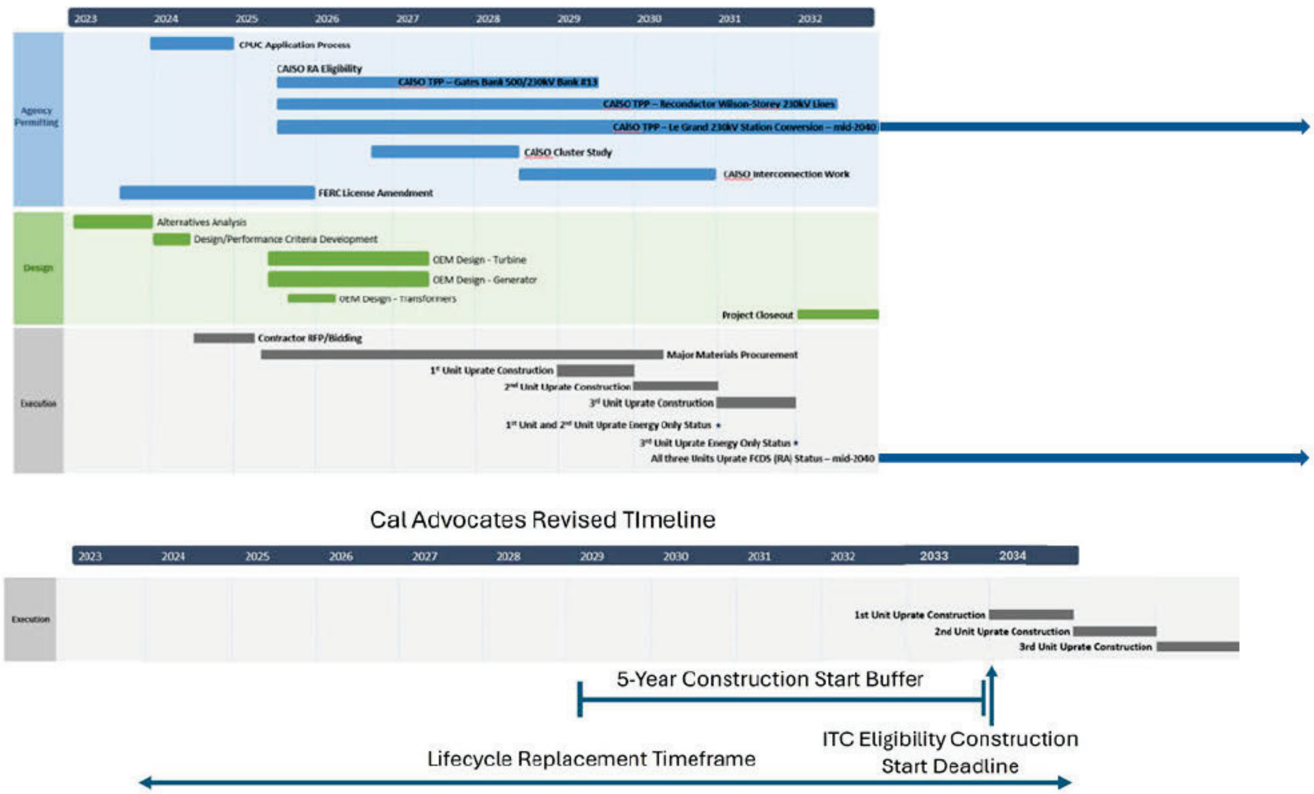
[190] PG&E Supplemental Testimony at 12.

[191] PG&E Supplemental Testimony at 11.

assertion that there is an urgent need to approve up-front cost recovery of $462 million is contradicted by the facts.

Figure 1-3 Cal Advocates Revised Project Timeline



III. CONCLUSIONS (Worhach)

PG&E has failed to meet its burden to establish that the Helms Uprate is reasonable. The Commission should not find that PG&E's request for a maximum cost cap of $462 million is reasonable at this time given the incomplete engineering design; unknown final capacity uprate amount; speculative cost projections; uncertain regulatory timelines; unknown eligibility date for RA value; undetermined ITC benefits; and ineligibility for the Commission's long-duration energy storage procurement order. At a minimum, the following additional information is needed for the Commission to be able to make a determination whether PG&E has sufficiently justified the reliefs sought in the Application:

- A detailed engineering design corresponding to a Class 3 AACE estimate.

- The uprate capacity that is most likely to be achieved, as demonstrated by the detailed engineering design.
- A contingency that is appropriate for a Class 3 AACE estimate to cover unforeseen costs rather than added costs due to the lack of sufficient planning.
- A demonstration that the Uprate has been deemed eligible for study in CAISO's interconnection connection study process.
- Evidence that CAISO will reserve TPD for the Uprate.
- A certain date by which the Helms Uprate will be eligible for RA as demonstrated by CAISO's approval of necessary long-lead time transmission projects.
- The certain ITC benefit amount that the Uprate and Lifecycle Replacement work will receive.
- Evidence that the Helms Uprate will be relicensed by FERC and that any terms of the renewed license will not significantly increase the costs or decrease the value of the project.
- Certain evidence regarding the need and any cost or schedule impacts of CEQA review.

CHAPTER 2 : COST-EFFECTIVENESS

I. INTRODUCTION (Worhach)

PG&E claims that the Helms Uprate and Lifecycle Replacement work is a cost-effective solution to meet California's affordability, climate, and resiliency goals.[192] In support of this claim, PG&E conducts a Net Market Value (NMV) analysis that purports to show that the project has positive NMV and thus is cost-effective.[193] PG&E also claims that the 150-180 MW Helms Uprate is more cost-effective than other long-duration storage options that could be procured in the Commission's IRP proceeding.[194] PG&E relies on the NMV analysis to support its request that the Commission issue an order finding that the Helms Uprate and Lifecycle Replacement work is cost-effective[195] and that the associated $462 million maximum cost cap is reasonable.[196]

However, PG&E fails to account for the numerous uncertainties of the Helms Uprate and Lifecycle Replacement in its NMV analysis. When included, Cal Advocates' analysis shows a much wider NMV range than PG&E advances. Moreover, the realized NMV may be significantly negative, indicating that the Helms Uprate is not cost-effective. Given the significant uncertainties of the Helms Uprate and Lifecycle Replacement work, the Commission cannot find that PG&E's request for cost recovery of up to a $462 million maximum cost is reasonable.

II. DISCUSSION (Worhach)

A. PG&E's Net Market Valuation Analysis Does Not Sufficiently Address Uncertainty

PG&E claims that the incremental Uprate capacity is cost-effective by providing an NMV analysis that is limited to two "bookend" scenarios: a low-capacity 150 MW generation and 0 MW pumping upgrade scenario and a high-capacity 180 MW and 73

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[192] Application at 1.

[193] PG&E Testimony at 3-18.

[194] Applications at 3-20.

[195] Application at 32.

[196] Application at 33.

MW pumping upgrade scenario.[197] In its supplemental testimony, PG&E revised the NMV analysis as presented in the Application to incorporate a delay in eligibility for RA capacity and revenues due to CAISO transmission constraints that will not be resolved until at least 2040.[198] PG&E's revised NMV analysis (PG&E Base: RA After 2040) shown in Table 2-1 shows that the NMV range is between [redacted] for the low-capacity scenario and [redacted] for the high-capacity scenario.[199] As discussed in Chapter 1 of this testimony, the final generating and pumping capacity upgrades are unknown, and thus the NMV is an uncertain value within this lower and upper range.

Furthermore, PG&E makes several assumptions that impact the NMV results. PG&E assumes that both the Helms Uprate and Lifecycle Replacement work will achieve the full 30% ITC benefit;[200] that the project will achieve FCDS in 2040;[201] that the project reaches full commercial operation in 2031 as an energy-only resource;[202] and that capital costs do not exceed the maximum cost cap.[203] Upon closer review of PG&E's NMV analysis and assumptions, it is unclear whether the Uprate is cost-effective even for the high capacity scenario. Cal Advocates prepared sensitivity scenarios that consider the numerous uncertainties inherent in the early conceptual design stage of the project. Cal Advocates' analysis indicates that the cost-effectiveness range with uncertainties is much wider than PG&E purports and that there is significant negative ratepayer value in several cases as set forth more fully below.

Table 2-1 shows a comparison of the PG&E Base: RA After 2040 base case scenario with several sensitivity scenarios. Cal Advocates first modifies the PG&E Base:

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[197] PG&E Testimony at 3-18.

[198] PG&E Supplemental Testimony at 10.

[199] PG&E Supplemental Testimony, Attachment A at AtchA-1.

[200] Attachment 34, PG&E response to Public Advocates Office Data Request 001, Question 3, at 1.

[201] PG&E Supplemental Testimony at 20.

[202] PG&E Supplemental Testimony at 20.

[203] Attachment 34, PG&E response to Public Advocates Office Data Request 001, Question 3, at 1.

RA After 2040 scenario to reflect a lower ITC value. In response to Cal Advocates' discovery, PG&E provided an alternative scenario in which only the Uprate capital costs are eligible for the ITC (PG&E Base: ITC for Uprate Only).[204] PG&E's case assumes a $45 million ITC.[205] Cal Advocates used this scenario as the basis for the additional sensitivity scenarios to consistently reflect the uncertainty in how the IRS will interpret and apply the final ITC eligibility rules. However, this sensitivity case is conservative. Depending on how the most recent ITC guidelines are implemented, the actual ITC benefit could be as low as $15 million, as discussed in Chapter 1.[206]

Cal Advocates' Sensitivity 1 (Sensitivity 1) removes all RA revenues to reflect the uncertainty of the date at which, if ever, the Uprate achieves FCDS. Scenario 1 serves as a lower bound value for a case in which the Uprate never achieves FCDS and continues to operate as an energy-only resource. Sensitivity 2 increases PG&E's capital cost forecast for the incremental Uprate to reflect PG&E's admission that capital costs may exceed the maximum cost cap.[207] Sensitivity 3 delays the operational date of the Uprate by one year, which may occur as a result of scope and schedule changes related to CAISO interconnection and FERC licensing.[208] Sensitivity 4 combines Sensitivities 1-3 to represent a lower range for the Helms Uprate NMV assuming the Uprate achieves FCDS in 2040. Sensitivity 5 includes all uncertainties, under the condition that the Uprate fails to achieve FCDS. Cal Advocates' analysis indicates that a revised bookend range of NMVs that include the uncertainties examined in this chapter is [redacted] to [redacted], which is much lower than PG&E's base case range of [redacted] to [redacted].

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[204] Attachment 35, PG&E Response to Public Advocates Office Data Request 011, Question 2, at 1-2.

[205] $45 million is 30% of the $150 million of incremental Helms Uprate capital costs relative to the Lifecycle Replacement capital cost of $300 million.

[206] $15 million is calculated based on the lower uprate capacity range of 150 MW: (150 MW / (1212 MW + 150 MW) times 30% times $450 million, which excludes the $12 million transmission upgrades that are ineligible for the ITC.

[207] PG&E Testimony at 4-7.

[208] PG&E Testimony at 4-8.

Table 2-1
Net Market Value Sensitivities

NMV Case	Low-Capacity Uprate NMV ($/kw-mo)	High-Capacity Uprate NMV ($/kw-mo)
PG&E Base: RA After 2040	[redacted]	[redacted]
PG&E Base, ITC for Uprate Only		
Sensitivity 1: PG&E Base, ITC for Uprate Only, No RA Value		
Sensitivity 2: PG&E Base, ITC for Uprate Only, 10% Higher Uprate Costs	[redacted]	[redacted]
Sensitivity 3: PG&E Base, ITC for Uprate Only, 1-Year Delay	[redacted]	[redacted]
Sensitivity 4: PG&E Base, ITC for Uprate Only, High Costs, 1-year Delay	[redacted]	[redacted]
Sensitivity 5: PG&E Base, ITC for Uprate Only, High Costs, 1-year Delay, No RA Value	[redacted]	[redacted]

Cal Advocates' NMV analysis indicates that the Uprate is not cost-effective in any of the sensitivity scenarios. PG&E's NMV analysis of just two capacity scenarios does not provide a reasonable estimate of the full potential range of value of the project given the many project uncertainties that PG&E acknowledges. As such, PG&E's cost-effectiveness analysis conflicts with the terms of the settlement agreement in PG&E's 2023 GRC in D.23-11-069, in which PG&E agreed that it could seek cost recovery in a subsequent application if "the project is shown to be cost-effective."[209] Moreover, PG&E has failed to show that the project is cost-effective with a reasonable degree of certainty and thus fails to demonstrate that its request for approval of a $462 million cost cap is just and reasonable. The following sections describe Cal Advocates' sensitivity cases in more detail.

[209] Application at 2.

B. ITC Uncertainty

As discussed in Chapter 1 of this testimony, PG&E assumes that both the Helms Uprate and the Lifecycle Replacement work will qualify for the 30% ITC, which if accurate would provide a $135 million tax credit.[210] However, PG&E's assumption is based upon stale proposed IRS guidelines published on November 30, 2023, which were revised on June 2, 2024, but are not yet finalized. The revised rules add a provision under which the ITC for capacity expansion to an existing facility is pro-rated by the added capacity relative to the existing capacity.[211] If based on pro-rated capacity, the revised ITC rules could result in a benefit as low as $15 million. If the IRS bases the final rules for the ITC on eligible capital costs for the additional capacity, the benefit could be as low as $45 million. In either case, comments by the NHA and the BCSE acknowledge that the June 2, 2024 proposed guidelines would reduce the ITC benefit for capacity additions to existing facilities depending on how the rules are interpreted and applied.[212]

In response to Cal Advocates' discovery, PG&E provided a revised NMV analysis in which only the incremental capital cost of the Helms Uprate is eligible for the ITC, resulting in a $45 million ITC benefit.[213] PG&E's revised NMV analysis, shown in Table 1-2 as "PG&E Base: ITC for Uprate Only," indicates that the NMV could fall anywhere between [redacted] and [redacted].

Because the June 2, 2024, IRS proposed guidelines represent the most up-to-date information regarding ITC eligibility, and because the final determination on the ITC is unknown, Cal Advocates uses a reduced ITC benefit in each of the additional sensitivity cases to consistently reflect ITC uncertainty. However, Cal Advocates uses the less conservative $45 million ITC instead of the more conservative $15 million pro-rated

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[210] PG&E Testimony at 2-14.

[211] KPMG report at 7.

[212] NHA Comments at 28.

[213] Attachment 36, PG&E response to Public Advocates Office Data Request 003, Question 2.b, at 3-4.

capacity ITC to represent a value between the lower and upper ranges of possible ITC benefits. Use of the lower ITC value of $15 million in Cal Advocates' sensitivities would further reduce the cost-effectiveness of the Uprate.

C. RA Value Uncertainty

As discussed in Chapter 1, PG&E assumes that the Uprate will eventually achieve FCDS and will earn RA revenues after 2040. However, PG&E's assumption is contingent on CAISO's approval of three new transmission projects as well as CAISO's approval of PG&E's request to reserve the available TPD for the Uprate in favor of the over 4.5 gigawatts (GW) of resources from earlier clusters in the CAISO transmission queue that are also seeking TPD in the Fresno local sub-area.[214] PG&E admits that the Helms Uprate will operate as an energy-only resource until it can achieve FCDS.[215] PG&E also admits the NMV of the Helms Uprate has "declined considerably"[216] in contrast to the NMV values presented in original Application that assumed FCDS in 2030.

Sensitivity 1: PGE Base, ITC for Uprate Only, No RA Value modifies the PGE Base, ITC for Uprate Only scenario to consider the situation in which the Helms Uprate does not achieve FCDS and must continue to operate without RA revenues through the remainder of its useful life.

Cal Advocates' analysis indicates that the NMV range for this scenario is [redacted] for the low-capacity case and [redacted] for the high-capacity case, which indicates that the Helms Uprate is not cost-effective.

D. Capital Cost Uncertainty

The PG&E Base: RA After 2040 NMV analysis assumes that capital costs will not exceed the maximum cost cap of $462 million.[217] However, PG&E indicates that its 50%

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[214] PG&E Supplemental Testimony at 9.

[215] PG&E Supplemental Testimony at 9.

[216] PG&E Supplemental Testimony, Attachment B, Independent Evaluator Addendum for Helms Uprate at 4.

[217] Attachment 34, PG&E response to Public Advocates Office Data Request 001, Question 3, at 1.

contingency estimate is "low-end"[218] and "minimum" by industry standards.[219] PG&E states that a high complexity Class 5 project such as the Helms Uprate could have a 50% contingency or more,[220] up to a 100% contingency, or double the base cost forecast.[221] PG&E foresees this possibility in its proposals of various mechanisms by which it would recover costs above the $462 million cost cap.[222]

Cal Advocates examined a sensitivity case in which the incremental capital cost for the Helms Uprate portion of the project is 10% higher than PG&E's estimate of $150 million with a 50% contingency.[223] This higher incremental capital cost case is equivalent to a 65% contingency applied just to the incremental Helms Uprate capital costs.

Cal Advocates Sensitivity 2: PG&E Base, ITC for Uprate Only, 10% Higher Uprate Costs indicates that a 10% capital cost increase decreases the NMV range to [redacted] for the lower-capacity case to [redacted] for the higher-capacity case and is therefore not cost-effective.

E. Operational Date Uncertainty

PG&E assumes that the Helms Uprate and Lifecycle Replace work will achieve full commercial operation by the end of 2031 as an energy-only resource.[224] However, PG&E admits that a delay in the commercial operation date of the project may occur due to additional work or general schedule delays, including delays for CAISO and FERC relicensing.[225] PG&E admits in its Supplemental Testimony that the CAISO

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[218] Application at 2.

[219] PG&E Testimony at 1-2.

[220] PG& Testimony at 2-11.

[221] Attachment 37, PG&E response to Public Advocates Office Data Request 008, Question 4, at 3-4.

[222] Application at 15.

[223] PG&E Testimony at 2-12.

[224] PG&E Supplemental Testimony at 20.

[225] Application at 12.

interconnection process is already delayed by at least two years, compared with PG&E's estimate in the Application.[226]

Cal Advocates modified PG&E's online date assumption in Scenario 3: PG&E Base, ITC for Uprate Only, 1-Year Delay to include a 1-year commercial operation delay. All else equal, and with no additional capital costs, a 1-year delay results in an NMV range of [redacted] to [redacted].

F. Cal Advocates' Combined Sensitivities Show that the Helms Uprate Could Result in Significant Negative Ratepayer Value.

Cal Advocates examined two final scenarios that combine the various uncertainties considered in this chapter. Sensitivity 4 combines PG&E Base: RA After 2040 with low ITC, high cost, and 1-year delay. Sensitivity 5 combines Sensitivity 1 PG&E Base: No RA Value with the other sensitivities. The NMV range for Sensitivity 4 is [redacted] to [redacted]. The NMV range for Sensitivity 5 is [redacted] to [redacted].

In contrast to PG&E's NMV calculation of [redacted] to [redacted], which PG&E relies on to justify its claim that the Helms Uprate is cost-effective, Cal Advocates calculates an overall NMV range considering all sensitivities of [redacted] to [redacted] for the low-capacity scenario and [redacted] to [redacted] for the high-capacity scenario. Cal Advocates' calculation of a wider range of NMV values, including potentially significantly negative NMVs, reflects the numerous uncertainties of the Helms Uprate and Lifecycle Replacement work. In contrast to PG&E's claim that the Helms Uprate is cost-effective, Cal Advocates' NMV sensitivity indicates that the Helms Uprate may not be cost-effective for the high-capacity scenario and will likely not be cost-effective in the low-capacity scenario, as PG&E acknowledges in its base case. If the Helms Uprate is not cost-effective it would burden ratepayers with costs that are not commensurate with value.

[226] PG&E Supplemental Testimony at 11.

G. Comparison of the Cost-Effectiveness of the Helms Uprate to Other Long-Duration Storage Alternatives

PG&E claims that the Helms Uprate is a cost-effective solution compared with other options that are available to meet the long-duration energy storage procurement mandates in the Commission's IRP program.[227] However, PG&E acknowledges that the Helms Uprate will not be eligible for the for long-duration storage procurement requirement adopted in the Commission's Mid-Term Reliability (MTR) procurement order D.21-06-035.[228] Notwithstanding the ineligibility of the Uprate for long-duration storage under the Commission's MTR procurement order, PG&E fails to demonstrate that the Helms Uprate is a needed and cost-effective option to meet *any* procurement for long-duration storage relative to other long-duration storage resources that could be procured between 2028 and 2031 or thereafter.

PG&E provides a comparison of the incremental Helms Uprate to shortlisted energy storage offers from its MTR Phase 3 Request for Offers (RFO).[229] PG&E's Phase 3 MTR RFO was issued on February 7, 2023 and the shortlist was presented to PG&E's Procurement Review Group (PRG) on May 9, 2023.[230] PG&E reports that the NMVs of these offers range between [redacted] and [redacted] for projects with online commercial operation dates in 2025 and 2026.[231] However, as PG&E has argued in other MTR procurement filings with the Commission, the high prices and low values of battery offers in its MTR RFO is due to recent high lithium carbonate prices[232] that

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[227] IE Report at 3-Atch3-15.

[228] Application at 5.

[229] PG&E Testimony at 3-20.

[230] PG&E, Mid-Term Reliability Request for Offers (RFO) – Procurement Updates, May 9, 2023.

[231] IE Report at 3-Atch3-15.

[232] For example, Attachment 38, PG&E advice letter E-7311, July 19, 2024, at 3: "Battery prices have risen significantly due to dramatic increases in commodity prices for lithium carbonate and metals used in manufacturing lithium-ion batteries. This impacts both initial construction costs and ongoing augmentation costs to maintain capacity. Although lithium prices have dropped from peak levels, the battery procurement costs … were incurred at prices higher than anticipated when the contract was executed in order to procure modules in time to meet the project milestones."

reflect the spike in lithium carbonate prices experienced in 2022 through early 2023.[233] As of November 2024, the price of lithium carbonate has returned to the much lower prices that prevailed before 2022.[234] The offers in PG&E 2023 RFO thus do not reflect the dramatic decline in lithium carbonate prices between 2023 and 2024.

The National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ABT) report indicates the cost of long duration energy storage will decline by 34% between 2023, when the MTR offers were received, and 2031, the deadline for MTR procurement.[235] Moreover, the NREL report indicates that there will be an additional cost decline of 15% between 2031 and 2040, when the Helms Uprate may at the earliest achieve FCDS and be eligible for procurement. The NREL ABT energy storage price forecasts are used in the Commission's IRP proceeding as an input to IRP's optimal portfolio expansion model and thus provide a reasonable data source for use in storage price benchmarking and comparison.[236] Because PG&E does not incorporate any cost decline for the other energy storage options, PG&E fails to demonstrate that the Helms Uprate is competitive with other options available over the same timeframe as it claims.

On October 15, 2024, PG&E issued a Request for Proposals (RFO) for long-duration energy storage resources to meet its MTR requirement pursuant to D.21-06-035 for resources with online dates between June 1, 2028 and June 1, 2031.[237] PG&E proposes to select a shortlist of offers by December 2024, and execute the final offers in

[233] The MTR Phase 3 bids that were submitted between in PG&E Phase 3 RFO reflect high lithium carbonate prices that were 451,385 Chinese Yuan (CNY) per ton on February 6, 2023, falling to 269,773 CNY/ton by May 15, 2023. See https://tradingeconomics.com/commodity/lithium.

[234] The price of lithium carbonate reached a peak of 560,000 CNY/ton in November 2022. As of November 21, 2024 the price is 79,400 CNY/ton, which is comparable to the price in February 2021. See https://tradingeconomics.com/commodity/lithium.

[235] NREL indicates that the 2023 capital cost of 8-hour duration utility scale batteries is $3,684/kW and will decline to $2,430/kW by 2031 in the NREL moderate cost decline scenario. Available at https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.

[236] CPUC, 2022-2023 Integrated Resource Planning Inputs and Assumptions, October 2023 at 44.

[237] Available at https://www.pge.com/en/about/doing-business-with-pge/wholesale-electric-power-procurement/long-lead-time-rfo.html?vnt=lltrfo. Accessed November 21, 2024.

the first half of 2025. PG&E's RFO for long-duration storage will provide the most current and viable set of alternative procurement for comparison with the Helms Uprate capacity in 2031. Once that information is available, PG&E should submit additional supplemental testimony as a baseline comparison for alternative long-duration energy storage.

Procurement beyond 2031 to meet future long-duration energy storage is speculative and should not be used as a justification for approval of the Application. However, if the Commission relies on this information, Cal Advocates' evidence for price forecast declines should be used to benchmark the RFO shortlisted procurement with procurement over the same time frame over which Helms may achieve deliverability and be eligible for any future procurement orders.

III. CONCLUSIONS (Worhach)

PG&E has failed to demonstrate that the Helms Uprate is cost-effective. The numerous project uncertainties examined in this chapter undermine the ratepayer value for the Helms Uprate much more than PG&E claims. As such, the Commission does not have sufficient information with sufficient certainty to find that the proposed $462 cost cap is reasonable.

APPENDIX A

QUALIFICATIONS OF WITNESSES

QUALIFICATIONS AND PREPARED TESTIMONY
OF
PAUL WORHACH

Q.1 Please state your name and business address.

A.1 My name is Paul Worhach. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) as a Senior Public Utilities Regulatory Analyst in the Electricity Planning and Policy branch.

Q.3 Briefly state your educational background and experience.

A.3 I hold a Ph.D. in Operations Research from the University of California Berkeley, and a Bachelor of Science in Engineering in Civil Engineering from Princeton University. I completed regulatory training provided by the National Association of Regulatory Utility Commissions ("NARUC") in 2023.

I joined Cal Advocates as the lead analyst on energy storage, including writing and coordinating testimony for utility applications in the Commission's biennial Energy Storage Procurement proceedings. I have provided testimony on behalf of Cal Advocates in A.20-03-002, A.20-03-003, A.20-03-004, A.20-04-013, and A.21-04-006. I have an additional 15 years of experience in consulting in California electricity and energy markets.

Q.4 What is the scope of your responsibility in this proceeding?

A.4 I am responsible for testimony for Chapter 1, Introduction, Sections A, B, C, G, H, and Conclusions, and Chapter 2.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
KAJ PETERSON

Q.1 Please state your name and business address.

A.1 My name is Kaj Peterson. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) as a Senior Utilities Engineer in the Electricity Planning and Policy branch.

Q.3 Briefly state your educational background and experience.

A.3 I hold a Bachelor of Science in Energy and Environment from KTH Royal Institute of Technology, and a Bachelor of Arts in Linguistics and Scandinavian Studies from North Park University. I am licensed as a professional engineer in mechanical engineering in the state of California by the Board for Professional Engineers, Land Surveyors, and Geologists. I joined the Electricity Planning and Policy Branch of the Public Advocates Office in July 2017.

Q.4 What is the scope of your responsibility in this proceeding?

A.4 I am responsible for testimony for Chapter 1, Introduction, Sections D, E, F.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

APPENDIX B

SUPPORTING ATTACHMENTS

LIST OF ATTACHMENTS FOR APPENDIX B

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7	68	Attachment 7	PG&E Response to Cal Advocates Data Request 007, Question 16.d
8	70, 78	Attachment 8	PG&E Response to Cal Advocates Data Request 003, Question 9
9	71, 79, 83, 85	Attachment 9	PG&E Response to Cal Advocates Data Request 001, Question 13, Utility Standard PM-1015S: Project Cost Management Standard
10	72, 73, 74, 76, 77, 80, 81, 82	Attachment 10	AACE International Recommended Practice No. 69R-12
11	86	Attachment 11	PG&E Response to Cal Advocates Data Request 003, Question 14
12	88	Attachment 12	PG&E Response to Cal Advocates Data Request 003, Question 10.c
13	91, 92, 113	Attachment 13	PG&E Response to Cal Advocates Data Request 001, Question 29
14	96, 97	Attachment 14	PG&E Response to CPUC Data Request 002, Question 5
15	98, 101, 102, 103	Attachment 15	PG&E Response to Cal Advocates Data Request 013, Question 11.c, 11.e

#	Footnote	Attachment	Description
16	99	Attachment 16	PG&E Response to Cal Advocates Data Request 013, Question 2
17	100	Attachment 17	PG&E Response to Cal Advocates Data Request 013, Question 6
18	104	Attachment 18	PG&E Response to Cal Advocates Data Request 005, Question 6
19	105, 117, 129	Attachment 19	PG&E response to Cal Advocates Data Request 005, Question 4
20	106	Attachment 20	PG&E Response to Cal Advocates Data Request 005, Question 10.d
21	112	Attachment 21	PG&E Response to Cal Advocates Data Request 001, Question 12, Attachment 1, Question 5
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31	164	Attachment 31	PG&E Supplemental Response to TURN Data Request 006 Question 9

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33	187, 189	Attachment 33	PG&E Response to TURN Data Request 008, Question 3
34	200, 203, 217	Attachment 34	PG&E Response to Cal Advocates Data Request 001, Question 3
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36	213	Attachment 36	Supplemental PG&E response to Cal Advocates Data Request 003, Question 2.b
37	221	Attachment 37	PG&E response to Cal Advocates Data Request 008, Question 4
38	232	Attachment 38	PG&E advice letter E-7331
39	94, 107, 109	Attachment 39 (Confidential)	Stantec Draft Report on Engineering Assessment for the Uprate of Helms Pumped Storage Plant
40	95, 111, 121, 124, 126, 127, 128	Attachment 40 (Confidential)	Stantec Analysis of Alternatives Helms Uprate

ATTACHMENT 1

PG&E Response to Cal Advocates Data Request 001, Question 27

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_001-Q027		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_001-Q027		
Request Date:	March 6, 2024	Requester DR No.:	PGE-A2312014-001
Date Sent:	March 20, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jennifer Scott	Requester:	Michael George/ Paul Worhach

SUBJECT: DATA REQUEST NO. PGE-A2312014-001

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* (Application).

QUESTION 027

Have the Joint Applicants conducted any analysis on the historical impacts of drought on the generating capacity of the Helms facility?

a. If so, provide the results of that analysis and any relevant workpapers.

ANSWER 027

No formal studies have been performed to evaluate drought impact on Helms, but historical review indicates no significant impact on capacity. During droughts, Helms typically remains fully available to run during the highest value hours of the day due to the amount of reservoir storage in Courtright and Wishon Reservoirs, which allows optimization of Helms dispatch plans in response to snow survey results and forecast water supply. The decreased total water supply during droughts affects generation in lower value periods, which decreases annual total energy generation but does not affect availability to run when needed.

ATTACHMENT 2

PG&E Response to Cal Advocates Data Request 001, Question 13.f

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_001-Q013		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_001-Q013		
Request Date:	March 6, 2024	Requester DR No.:	PGE-A2312014-001
Date Sent:	March 20, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jenn Scott	Requester:	Michael George/ Paul Worhach

SUBJECT: DATA REQUEST NO. PGE-A2312014-001

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* (Application).

QUESTION 013

PG&E and Pacific Generation LLC (the Joint Applicants) state that the Helms Uprate forecast corresponds to an American Association of Cost Engineering (AACE) Class 5 estimate.[1] The Joint Applicants state that AACE guidelines indicate the need for a contingency of 50 percent or more for the Helms Uprate project.[2] The Joint Applicants characterize the 50 percent contingency used in the Helms Uprate cost estimate as a ”low-end”[3] and “minimum”[4] contingency by industry standards.

a. Provide studies, analysis, or other documentation that supports the claim that the Helms Uprate meets the specific guidelines for an AACE Class 5 estimate as contained in the AACE 56R-08 cost estimation standard.[5]

ANSWER 013A

PG&E’s Utility Standard PM-1015S “Project Cost Management Standard” is an internal cost estimate standard that provides direction on estimate classification. This standard is attached and is titled HelmsUprateProject_DR_CalAdvocates_001-Q013Atch01.

The PG&E standard references multiple AACE guidelines as listed on pages 21-22. It should be noted that different AACE guidelines provide for different ranges of

1 Application, Prepared Testimony at 2-11.
2 Application, Prepared Testimony at 2-11.
3 Application at 2.
4 Application, Prepared Testimony at 1-2.
5 American Association of Cost Engineers, Cost Estimate Classification System, 56R-08, Tables 1-3.

contingency use for each of the estimate classes. The most applicable AACE guideline is 69R-12 for Hydropower Industry (see table below).

The team used the Maturity Level and Eng Usage Guidelines from 69R-12 and professional judgement to determine the Estimate Class was Class 5.

COST ESTIMATE CLASSIFICATION MATRIX FOR THE HYDROPOWER INDUSTRY

	Primary Characteristic	***Secondary Characteristic***		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

Table 1 – Cost Estimate Classification Matrix for the Hydropower Industry

69R-12 indicates for Class 5 a contingency range of 30% - 100% on the high end (-20% to -50% on the low end). The table on page 17 of the PG&E Standard uses the AACE guidelines referenced to then stipulate a recommended contingency value based on complexity of the project. The table is titled Table 3 Complexity Factors and shows for Class 5, a contingency amount of 20% for low complexity projects and 100% for high complexity projects. Though the Helms Uprate project is a high complexity project, it was decided that using 50% contingency, in line with a Class 4 high complexity project, was more appropriate than using 100% contingency.

b. Provide definitions and references to industry standards for the terms “low-end” and “minimum” in the context of industry standard contingency values.

ANSWER 013B

“Low-end” describes a contingency value that is towards the low-end of the range (below the mid-point). Per the PG&E Project Cost Management Standard, contingency includes both AACE cost uncertainty and Risk uncertainty. A 50% contingency that covers both AACE cost uncertainty and Risk uncertainty, is below the recommended contingency for a class 5 estimate on a high complexity project.

c. Provide a reference to any and all industry standards that demonstrate that the contingency value used to develop the Helms Uprate cost estimate is a “low-end” and “minimum” contingency.

ANSWER 013C

See responses in 13a. and 13b.

d. The Black and Veatch feasibility study uses a 30% contingency to estimate the cost of the Helms Uprate project.[6] Explain the reason for the discrepancy between the contingency value used by the Joint Applicants and the contingency used by Black and Veatch.

ANSWER 013D

The screenshot below is from the report referenced. Section 7 refers to the AACE Class 5 estimate guidelines used in the development of the estimate (-20% to +50%) and is used to develop the range of costs shown of $263-493M in the “Estimate Range” in the below table. The 30% contingency referenced in the second paragraph is shown in the table below as “Contingency” at a value of $51.5M. This 30% contingency is added to Direct Costs as a placeholder to arrive at the “Total Parametric Cost Estimate”, which is then multiplied by the AACE Class 5 range to arrive at the total “Estimate Range”.

In summary, the study provided a base estimate, applied 30% contingency, and then applied another 50% contingency to calculate the high-end of the range at $493M. This is essentially use of 95% contingency ((base x 1.3) x 1.5 = base x 1.95) on top of the base estimate.

6 Application, Prepared Testimony, Attachment E at 2-AtchE-47.

7.0 Cost Estimates

Black & Veatch prepared AACE, Class 5 cost estimates for each of the alternatives utilizing internal experience and knowledge from recent, similar pump storage feasibility studies. The result is a baseline cost with a range of -20 percent or +50 percent. Costs developed are for full engineering, procurement, and construction. Indirect costs shown include costs associated with contractor general conditions, contractor overhead and profit, startup and commissioning, insurance, and tax but do not include PG&E labor costs or permitting costs. Cost also do not include any required modifications to substations or transmission lines required to transmit the additional energy generated. They also do not include costs for potential modifications to the existing surge chambers which may be required due to the increase in flow through the tunnels. A summary of the cost estimate for each alternative is outlined below.

The cost estimates include a contingency equal to 30% of the estimated direct costs. As the alternatives are further developed with additional studies and design, the contingency will be reduced. One of the largest cost drivers for the project is the equipment cost. During the next phase of the project, budgetary quotes should be solicited for major equipment to further refine the project costs.

7.1 ALTERNATIVE 1 - UPRATE OF EXISTING UNITS TO 460 MW EACH

Table 7-1 shows the estimated costs associated with uprating the existing three units to 460 MW each. The costs include rewinding Units 1 and 3 similarly to the recently rewound Unit 2 as well as replacing all of the existing runners with new ones that have been optimized for the higher flow and lower head conditions. Costs for replacing the TSVs with new ones that are designed for the higher flow are not included since PG&E is already in the process of procuring those new valves.

Table 7-1 **Parametric Cost Estimate for Uprating the Existing Units**

DESCRIPTION	COST
Rewind Units 1 and 3	$24,000,000
Procure New Runners	$111,000,000
Electrical Equipment Upgrades	$21,000,000
Equipment Installation	$39,600,000
Total Direct Costs	***$195,600,000***
Contingency	$51,500,000
Indirect Costs	$81,300,000
Total Parametric Cost Estimate	***$328,400,000***
Estimate Range	**$263-493M**
Cost/Installed kW Range (165 MW Uprate)	**$1,594-$2,988**

e. Provide any input from subject matter experts and the historic benchmarking data from similar prior work at Helms that was used to develop the Helms Uprate cost estimate.[7]

ANSWER 013E

The “Bad Creek” pumped storage project, recently uprated by Duke Energy was used to compare scope, lessons learned and ROM (rough order of magnitude) costs. ROM costs for major contracts were compared to Uprate estimates to confirm costs were in the “ballpark”. Due to differences in project timing, project location, actual unit differences (Helms units are larger) and company costing structures, these costs were only used as a high-level ROM comparison.

Helms Rewind U2 – This project was used to develop internal estimates and confirm project estimates provided by consultants. This project was conducted from 2016-2020 and provides a partial scope comparison to the Uprate project scope. The final cost of

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[7] Application, Prepared Testimony at 2-11.

the Helms U2 Rewind served as the starting point and then costs were adjusted for the Uprate generator scope and timing of installation (U1 and U3 generator rewinds and replacement of rotor poles on all 3 units).

Other similar work (turbine and transformer replacements) performed in the recent past at other PG&E hydro facilities were also referenced to improve cost estimations for the Uprate.

f. What is the cumulative number of hours and costs expended to date to develop the Helms Uprate cost estimate? Provide a breakdown of hours and expenses for PG&E staff and for each consultant.

ANSWER 013F

Number of hours and the associated labor cost was not tracked for the task: “develop the cost estimate”. We can provide a best guess as to how many hours were spent on development of the Uprate cost estimate and the approximate hourly rate.

Estimator	hours	rate/hr*	$
PG&E PL	40	215	$8,600
PG&E PM	60	215	$12,900
PG&E Engineering	40	215	$8,600
B&V	25	215	$5,375
Total	165	215	$35,475

*rate presented is an estimated blended rate of all contributors

ATTACHMENT 3

PG&E Response to Cal Advocates Data Request 009, Question 1

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_009-Q001		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_009-Q001		
Request Date:	July 11, 2024	Requester DR No.:	PGE-A2312014-009
Date Sent:	July 31, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	James L. Higham, Jr.	Requester:	Matthew George/ Paul Worhach

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* ("Application).

QUESTION 001

On June 3, 2024, the United States Internal Revenue Service (IRS) posted proposed regulations relating to the clean electricity production credit and the clean electricity investment credit established by the Inflation Reduction Act of 2022 under Section 48E, Clean Electricity Investment Credit.[1] In particular, proposed § 1.48E-4(b)[2] would provide rules related to the expansion of capacity of a qualified facility by the addition of a new unit or an addition of capacity and the corresponding eligibility for the Investment Tax Credit (ITC).

a. Has PG&E assessed how the proposed rules will impact the ITC eligibility of the Helms Uprate? If so, provide PG&E's assessment. If not, explain why not.

b. Has PG&E conducted a net market valuation of the Helms Uprate corresponding to the proposed Section 48E regulations? If so, provide the NMV analysis. If not, explain why not.

c. Will PG&E submit comments in the IRS Clean Electricity Production Credit and Clean Electricity Investment Credit docket?[3] If so, provide PG&E's comments upon submission in the docket. If not, explain why not.

ANSWER 001

a. PG&E is still in the process of reviewing Proposed Treasury Regulations §§ 1.45Y and 1.48E and their implications on the Helms Uprate Application; however, based on PG&E's initial review, the proposed regulations do not appear to contradict the ITC analysis contained in PG&E's Application and Prepared Testimony. PG&E is continuing to evaluate the proposed regulations and will provide an update to this

1 See https://www.federalregister.gov/documents/2024/06/03/2024-11719/section-45y-clean-electricity-production-credit-and-section-48e-clean-electricity-investment-credit.

2 See https://www.federalregister.gov/d/2024-11719/p-268.

3 See https://www.regulations.gov/document/IRS-2024-0026-0001.

initial assessment upon completion of PG&E's detailed review of the proposed regulations.

In this data request, PAO specifically references Prop. Treas. Reg. § 1.48E-4(b) which is titled "Expansion of facility; Incremental production." PG&E would like to point out that the Proposed Treasury Regulations separately address qualified facilities and energy storage technology (EST). Prop. Treas. Reg. § 1.48E-2 separately outlines the proposed rules for qualified investments in ***qualified facilities*** and ***energy storage technology (EST***) for purposes of I.R.C. § 48E (emphasis added).

The I.R.C. § 48E credit applies to both qualified facilities as defined in I.R.C. § 48E(b)(3)(A) and energy storage technology as defined in I.R.C. § 48E(c). Prop. Treas. Reg. § 1.48-2(g)(6)(i) defines types of EST to include physical storage such as pumped storage hydropower. The requirements related to the expansion of capacity of a qualified facility found in Prop. Treas. Reg. § 1.48E-4(b) are applicable only to qualified facilities and do not reference EST. The rules related to the modification of EST are found in Prop. Treas. Reg. § 1.48E--2(g)(7) and provide that a modification to or expansion of EST will be treated as electrical energy storage property, except for the basis of any existing electrical energy storage property prior to such modification.

b. Based on PG&E's initial assessment of the proposed regulations, the ITC assumptions in PG&E's Application and Prepared Testimony have not changed and therefore have not required an additional net market valuation analysis of the Helms Uprate.

c. No, PG&E will not be submitting comments on Prop. Treas. Regs. §§ 1.45Y and 1.48E. Rather than submitting comments as an individual taxpayer, PG&E participates in the comment process through its membership in industry associations.

ATTACHMENT 4

PG&E Response to Cal Advocates Data Request 002, Question 4

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_002-Q004		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_002-Q004		
Request Date:	March 18, 2024	Requester DR No.:	PGE-A2312014-002
Date Sent:	April 1, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jennifer Scott	Requester:	Michael George/ Paul Worhach

SUBJECT: DATA REQUEST NO. PGE-A2312014-002

The data request pertains to Application (A.) 23-12-014, Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs (Application).

QUESTION 004

The Joint Applicants indicate that PG&E will finalize an initial draft of the FERC License Amendment in April 2024.[1] Provide the initial finalized draft FERC License Amendment and all related material when available.

ANSWER 004

We will provide the initial finalized draft FERC License Amendment when it is available. We are on track for submitting the draft application in May and will provide the documentation following submittal.

1 Application, Prepared Testimony at 2-9.

ATTACHMENT 5

PG&E Response to Cal Advocates Data Request 001, Question 23

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_001-Q023		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_001-Q023		
Request Date:	March 6, 2024	Requester DR No.:	PGE-A2312014-001
Date Sent:	March 20, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jennifer Scott	Requester:	Michael George/ Paul Worhach

SUBJECT: DATA REQUEST NO. PGE-A2312014-001

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* (Application).

QUESTION 023

The Joint Applicants state that it is expected that the Helms Uprate will qualify for a Non-Capacity Amendment for Federal Energy Regulatory Commission (FERC) relicensing.[1]

a. If the Helms Uprate does not meet the criteria for a Non-Capacity Amendment, under what alternative type of relicensing would the Helms Uprate occur?

ANSWER 023A

If the Helms Uprate does not meet the criteria for a Non-Capacity Amendment, then a Capacity Amendment would be pursued.

b. Provide an estimate of the potential impacts on project schedule and costs if the Helms Uprate does not meet the criteria for a FERC Non-Capacity Amendment and instead must be relicensed under alternative criteria.

ANSWER 023B

If a Capacity Amendment was needed, the schedule to obtain the Amendment could increase 12-24 months primarily because a Capacity Amendment requires three-stage consultation. The first stage requires PG&E to prepare an Initial Consultation Document (ICD) and submit it to interested stakeholders. The ICD describes the proposed modifications, including identification of the environment that many be affected, any protection and mitigation measures proposed by PG&E, proposed studies, and other supporting information. The second stage requires PG&E to conduct any necessary

1 Application, Prepared Testimony at 2-9.

studies and file a draft application to interested stakeholders for comment. The third stage requires PG&E to file the final application with FERC. It is difficult to estimate the additional cost for a Capacity Amendment because of the variables of increased consultation and potential additional studies, but a reasonable rough order of magnitude estimate would be $200,000 to $1,000,000.

ATTACHMENT 6

PG&E Response to Cal Advocates Data Request 006, Question 3

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_006-Q003		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_006-Q003		
Request Date:	May 16, 2024	Requester DR No.:	PGE-A2312014-006
Date Sent:	June 4, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Rebecca Doidge	Requester:	Michael George/ Paul Worhach

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* (Application).

QUESTION 003

Regarding PG&E's application submitted to the Federal Energy Regulatory Commission (FERC) to relicense Helms (Project No. 2735-104), provide the following:

a. The license application and all related materials submitted to the FERC.

b. All relevant correspondence between and comments received by PG&E from the following agencies:

   i. California State Water Resources Control Board (SWRCB)

   ii. California Department of Fish and Wildlife (CDFW)

   iii. United States Fish and Wildlife Service (USFWS)

   iv. All other relevant federal and state agencies or boards.

c. Provide Cal Advocates with password access to the following website: https://helmsrelicensing.com/.

ANSWER 003

a. The license application and all related materials have been submitted to the FERC. The Final License Application was filed with FERC on April 18, 2024, and is found on the FERC e-Library (eLibrary | General search (ferc.gov)) Accession No. 20240418-5301, 20240418-5302, and 20240418-5303. It is also found on the e-Library by searching Docket P-2735-104. Pursuant to an e-mail exchange on May 29, 2024, PG&E and Cal Advocates agreed that PG&E would initially provide the public documents associated with its FERC license application. Cal Advocates reserved its right to renew its request for the non-public documents attached to the FERC license application. The public version of the FLA consists of the following:

   1. Volume I (Public) and includes the Initial Statement and Exhibits A, B, C, D, G, and H (available via FERC e-Library).
   2. Volume II (Public) and includes Exhibit E (available via FERC e-Library).

b. The relevant correspondence and meetings are summarized in Attachment E1 of the FLA. This is found on pages 1-763 of 20240418-5031-04 Helms FLA P-2735 Public Vol II Att E1-E2 (available via FERC e-Library).

c. PG&E provided Cal Advocates with the password access to the following website: https://helmsrelicensing.com/, via e-mail exchange on May 29, 2024.

ATTACHMENT 7

PG&E Response to Cal Advocates Data Request 001, Question 16d

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_001-Q016		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_001-Q016		
Request Date:	March 6, 2024	Requester DR No.:	PGE-A2312014-001
Date Sent:	March 20, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Erica Brown	Requester:	Michael George/ Paul Worhach

SUBJECT: DATA REQUEST NO. PGE-A2312014-001

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* (Application).

QUESTION 016

PG&E states it currently records net above-market costs associated with the Helms facility through the Legacy Utility Owned Generation (UOG) Subaccount.[1]

a. Have the associated costs and revenues resulted in a net credit via the Power Charge Indifference Adjustment (PCIA) in any of the last 5 years?
b. Is there a fixed duration for which unbundled customers are responsible for costs associated with the current Helms facility?
c. Will the duration of unbundled customer cost responsibility change under PG&E's proposed Helms Uprate cost allocation mechanism?
d. What would be the remaining useful life of the Helms facility after the Helms Uprate project is completed?
e. Provide an estimate of the forecasted costs and benefits (broken down across bundled and unbundled customers) associated with the incremental Helms Uprate versus Lifecycle Replacement work.

ANSWER 016

a. Yes, costs and revenues associated with the Helms facility have resulted in a net credit via the PCIA in every one of the past five years. For further details, including a breakdown of General Rate Case costs, net CAISO revenues, Retained Resource Adequacy value and net credits on an annual basis, please see the attached Excel spreadsheet PG&E provides, titled "HelmsUprateProject_DR_CalAdvocates_001-

1 Application, Prepared Testimony at 1-3.

Q0016_Attachment_CONF", along with a confidentiality declaration signed by Rebecca Katerndahl.

b. There is no fixed duration for which unbundled customers are responsible for *net* costs (inclusive of both costs and potential revenues or credits in the event that the Helms facility generates net revenues) associated with the current Helms facility. In D.18-10-019, the Commission explicitly reviewed whether the costs of "Legacy" (pre-2002) Utility Owned Generation ("UOG") falls within the scope of net costs that can be allocated to CCA departing load customers, and found that, "[r]ecoverable costs clearly encompasses Legacy UOG."[2] Furthermore, the Commission in that decision also explicitly analyzed whether there should be a 10-year limitation on recovery of post-2002 UOG costs and explicitly rejected such arguments, finding, "[w]e see no justification to continue a 10-year limit on recovering costs for post-2002 UOG from departing load".[3] Although the Helms facility is classified as UOG, it is also a pumped-storage facility, and out of an abundance of caution PG&E also points to the Commission's finding on energy storage resources: "[s]imilar to the conclusions above regarding post-2002 UOG costs, we find that PCIA-eligible energy storage resources should be treated in the same manner as other resources in the IOU portfolio and should not be subject to a 10-year limitation on cost recovery."[4] Thus, PG&E concludes that there is no fixed duration for which unbundled customers are responsible for *net* costs associated with the current Helms facility.

c. No, the duration of unbundled customer cost responsibility will not change under PG&E's proposed Helms Uprate cost allocation mechanism. PG&E points to its answer to Question 16.B above in response to this question for further discussion, which cites the Commission as stating: "[w]e see no justification to continue a 10-year limit on recovering costs for post-2002 UOG from departing load".[5]

d. The Helms Facility is currently in the process of renewing its FERC License and will file the Final License Application by April 30, 2024. The current license expires April 30,

[2] D.18-10-019, at 54.
[3] Ibid, at 59.
[4] Ibid, at 60.
[5] Ibid, at 59.

2026, and PG&E anticipates FERC will issue a new license in about 2028-2030. The Helms Uprate Project will be an amendment to the existing license and is expected to be approved before a new license is issued. FERC will consider a 50-year license term based on meeting certain criteria which PG&E anticipates meeting. Therefore, assuming a new 50-year license is issued in 2029, the life of the facility will extend through at least 2079. Many hydroelectric facilities have been in operation for more than 100 years and Helms is certainly capable of the same operation duration.

e. PG&E does not have any workpapers directly responsive to this question. However, PG&E provides the following simplified breakdown. First, PG&E took the forecasted incremental benefits, discounted to 2024 dollars, for the expected lifespan of the facility for the upper and lower ranges of expected incremental capacity under the Uprate scenario, as well as the existing facility under the Lifecycle scenario. Second, PG&E took the total forecasted revenue requirement, discounted to 2024 dollars, for the expected lifespan of the facility for the Uprate scenario and the Lifecycle scenario. Note that the total forecasted revenue requirement for the Uprate scenario includes the potential ITC credit, while the Lifecycle scenario does not due to ineligibility. Unlike in PG&E's net market value analysis, here PG&E provides the absolute forecasted costs associated with each scenario and does not calculate the incremental costs, but does provide the forecasted incremental benefits associated with each scenario.. Because the Helms facility's net costs are recovered via the PCIA, PG&E then pro-rated the costs and benefits, as seen in the tables below, by the percentage of load that is bundled or departed, and according to its proposed cost allocation methodology. PG&E also notes that the bundled and departed load allocation factors are based on PG&E's 2024 sales forecast for illustrative purposes and these factors will change over time depending on load migration and relative load growth between bundled and departed load customers, among other factors. Because of the manner in which net costs are allocated to customers via the PCIA methodology, PG&E stresses that these should not be viewed as actual costs or benefits that will be passed to bundled or departed load customers, but instead represents an illustrative answer to the question.

Percentage of Total Costs/Benefits Allocated to Bundled and Departed Load			
	Baseline Capacity (MW)	150 MW Incremental Capacity (MW)	180 MW Incremental Capacity (MW)
Total Capacity	1212	1362	1392
Percentage of Total Costs/Benefits Allocated to New PCIA Vintage[6]	0%	11%	13%
Percentage of Total Costs/Benefits Allocated to Legacy UOG Vintage[7]	100%	89%	87%
Percentage of Legacy UOG PCIA Vintage Allocated to Bundled Load[8]	41%	41%	41%
Percentage of Legacy UOG PCIA Vintage Allocated to Departed Load[9]	59%	59%	59%
Percentage of Total Costs/Benefits Allocated to Bundled Load[10]	41%	47%	49%
Percentage of Total Costs/Benefits Allocated to Departed Load[11]	59%	53%	51%

[6] Calculated as the portion of incremental Uprate nameplate capacity to the new, total capacity after the Uprate, expressed as a percentage.

[7] Calculated as the portion of the existing Helms nameplate capacity to the new, total capacity after the Uprate, expressed as a percentage.

[8] The percentage of net costs allocated to bundled load via the Legacy UOG Vintage under the PCIA methodology. Values derived from PG&E's PCIA Rate Calculation Workpapers in its 2024 Energy Resource Recovery Account ("ERRA") Forecast Application.

[9] The percentage of net costs allocated to departed load via the Legacy UOG Vintage under the PCIA methodology. Values derived from PG&E's PCIA Rate Calculation Workpapers in its 2024 Energy Resource Recovery Account ("ERRA") Forecast Application.

[10] Calculated as the percentage of total cost/benefits allocated to the future to-be-established PCIA vintage, plus the product of the percentage of total costs/benefits allocated to Legacy UOG Vintage Legacy multiplied by the percentage of Legacy UOG PCIA vintage allocated to bundled load.

[11] Calculated as the product of the percentage of total costs/benefits allocated to Legacy UOG Vintage Legacy multiplied by the percentage of Legacy UOG PCIA vintage allocated to departed load.

Forecasted Project Costs for Bundled and Departed Load ($PV)					
Scenario	Forecasted Project Cost	Bundled Load Percentage	Departed Load Percentage	Forecasted Costs for Bundled Load	Forecasted Costs for Departed Load
Uprate – 150 MW Incremental	$348,882,487	47%	53%	$163,974,768.89	$184,907,718.11
Uprate – 180 MW Incremental	$348,882,487	49%	51%	$170,952,418.63	$177,930,068.37
Lifecycle	$256,229,470	41%	59%	$105,054,082.70	$151,175,387.30
Forecasted Incremental Helms Benefits for Bundled and Departed Load ($PV)					
Scenario	Forecasted Incremental Benefits[12]	Bundled Load Percentage	Departed Load Percentage	Forecasted Incremental Benefits for Bundled Load	Forecasted Incremental Benefits for Departed Load
Uprate – 150 MW Incremental	$111,616,876	47%	53%	$52,459,931	$59,156,944
Uprate – 180 MW Incremental	$193,775,664	49%	51%	$94,950,075	$98,825,588
Lifecycle	$0	41%	59%	$0	$0

[12] Forecasted incremental benefits include forecasted benefits for energy, Resource Adequacy, and ancillary services.

ATTACHMENT 8

PG&E Response to Cal Advocates Data Request 003, Question 9

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_003-Q009		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_003-Q009		
Request Date:	March 29, 2024	Requester DR No.:	PGE-A2312014-003
Date Sent:	April 22, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jenn Scott	Requester:	Michael George/ Paul Worhach

QUESTION 009

Referring to the terms used in Figure 5 of PG&E's Project Cost Management Standard (Utility Standard: PM-1015S) and the capital cost figures in Table 2-1 of PG&E's testimony, is the "Base Estimate" for the project $308.13 million, the "Expected Case (Authorized Amount)" $462.197 million, and the contingency $154.066 million?

a. Please confirm or correct the terminology and the dollar figures above.

ANSWER 009

a. Base Estimate is $308.131M and the High Case Estimate is $462.197M, with a total contingency amount of $154.066M. Table 2-1 did not provide an Expected Case calculation.

ATTACHMENT 9

PG&E Response to Cal Advocates Data Request 001, Question 13, Utility Standard PM-1015S: Project Cost Management Standard

Project Cost Management Standard

SUMMARY

This Standard provides requirements and guidance on projects for Cost, including Work Breakdown Structure (WBS), Project Cost Estimating, Project Cost Baseline, Risk Management, and Cost Control.

TARGET AUDIENCE

This Standard applies to Project/Program Sponsors, Functional Area (FA) Project/Program Leadership, Project Managers, Project Controls Analysts, Project/Program Stakeholders and all other employee and non-employee workers (together, personnel) of PG&E Corporation (Corporation) and its controlled subsidiaries, including Pacific Gas and Electric Company (Utility) (together, PG&E) working on PG&E projects.

SAFETY AND HEALTH

This Standard must be implemented in accordance with all safety-related Standards, Procedures, and practices. Nothing is more important to us than public, employee and contractor safety and health. All Serious Injuries and Fatalities (SIFs) associated with any major project or program must be identified in the CAP system and compliance with SAFE-1100S, "Serious Injury and Fatality (SIF) Standard" is required. Planning and execution of projects and programs must put safety first. Examples include applying lessons learned, developing, and updating project specific safety plans, prioritizing safety at all meetings and reviews, identifying and addressing field safety hazards, promoting a safety culture, and communicating safety by public outreach. Additional information is available on the PG&E Safety website: http://pgeweb.utility.pge.com/safety/

RISK

This Standard must be implemented in accordance with RISK-5001S, "Enterprise and Operational Risk Management Standard" and RISK-5001P-01, "Enterprise and Operational Risk Management Procedure". RISK-5001S describes the requirements, roles, and responsibilities for identifying and evaluating enterprise and operational risks, responding to those risks, and monitoring those risks with the overall objective to measurably reduce enterprise and operational risk. RISK-5001P-01 provides instructions for: risk scoring; risk mitigation alternatives analysis; and calculating risk spending efficiency (RSE) metric for mitigation alternatives.

APPLICABILITY

This Standard applies to all PG&E projects with an estimated Total High Case of at least $1 million.

Project Management Cost may apply to multiple departments internal and external to an organization to execute the requirements contained in this Standard.

Projects with an estimated Total High Case of less than $1 million are not subject to the requirements set out in this Standard. Functional Areas (FAs) are responsible and have discretion for establishing cost management guidance for projects less than $1 million.

EXCEPTION REQUESTS

The Functional Areas can request an exception to a requirement in a standard for all their programs or projects, an individual program or project, or category of programs or projects (e.g., Major Work Category or Major Activity Type code). SEE PM-1001P-06, "Enterprise Project Governance Guidance Document Exception Request Procedure".

Approved requests must be documented in the corresponding FA procedure.

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Project Cost Management Standard

Project Cost Management Standard

REQUIREMENTS

1 Functional Area (FA) Applicability Requirements

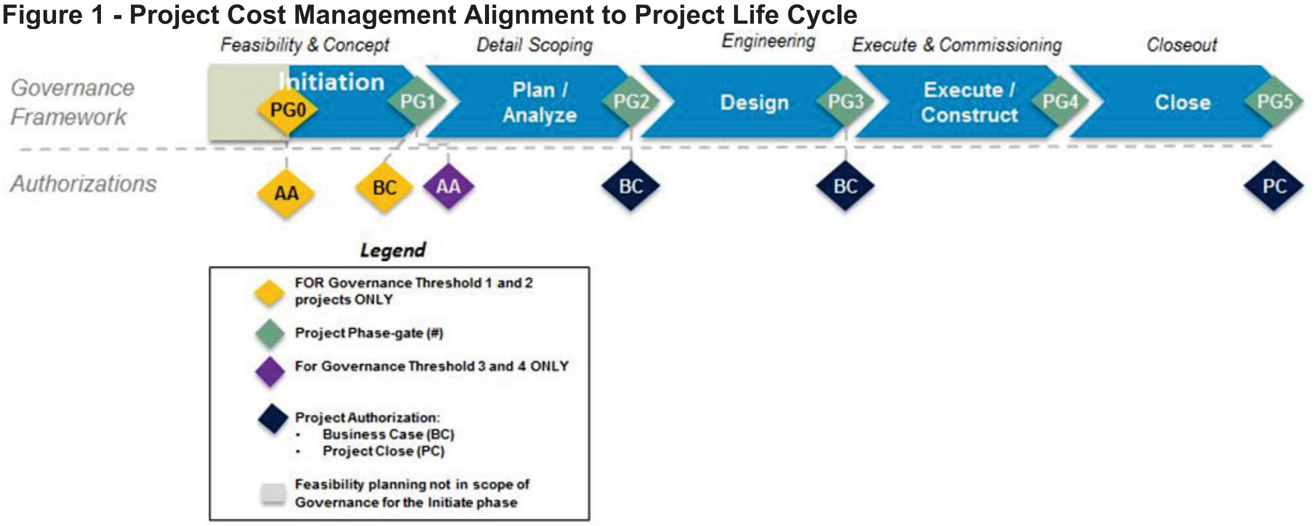
1.1 PG&E Organizations that perform or are responsible for projects with an estimated Total High Case of $1 million or greater must have procedures in accordance with GOV-2001P-01, “Guidance Document Development, Review, and Revision Procedure” that implement the requirements contained within this Standard.

1.2 Projects with an estimated an estimated Total High Case of less than $1 million are not subject to the requirements set out in this Standard. Functional Areas (FAs) are responsible and have discretion for establishing cost management guidance for projects less than $1 million.

1.3 Project Cost Management aligns with the project life cycle from PM-1010S, “Project Management Governance Standard”, as is illustrated in Figure 1 below, which is to be used as a reference in the interpretation of this Standard.

1.4 Projects within Information Technology (IT) using an Agile approach (e.g., IT’s Business Technology Digital Catalyst projects) are exempt from the requirements within this Standard.

Figure 1 - Project Cost Management Alignment to Project Life Cycle



2 Work Breakdown Structure (WBS)

2.1 All projects must use the appropriate levels, elements, and numbering scheme (as defined in this Standard). Applies only to SPSI managed projects.

1. The WBS must be developed through a decomposition of the project scope of work into discrete elements for which work can be planned and managed effectively.

2. The WBS must reflect the total scope of work to be performed on the project.

3. The WBS must be used to establish the Project Cost Baseline against which project cost performance is measured and controlled.

4. The WBS must be the common reference for internal and/or external project reporting.

5. There must be only one WBS for each project.

6. All costs (including labor, material, contracts, and overhead) and resources for a project must be mapped to a WBS element.

7. The WBS must be updated to include revisions for approved changes and modifications throughout the project's life cycle.

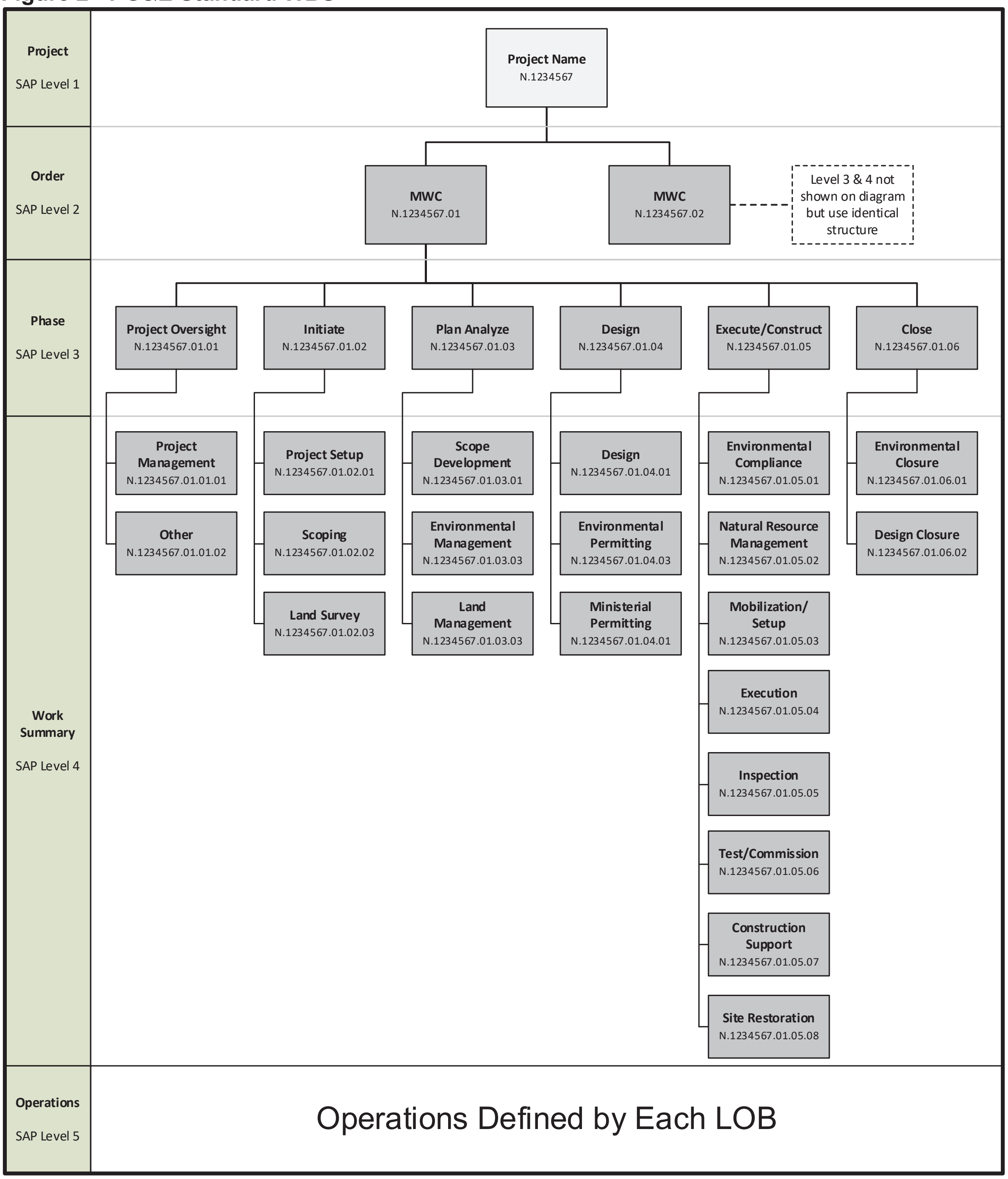
8. The WBS must be in the SAP Project Systems (SAP PS) WBS of the SAP Enterprise Central Component (ECC) or other EPG approved tool.

9. The WBS numbering scheme must meet the requirements listed in Figure 2.

10. FA specific WBS's are documented in Appendix G, "WBS Attribute Table, Naming Conventions, Abbreviations." Any further exceptions must be approved by the EPGO and documented.

Project Cost Management Standard

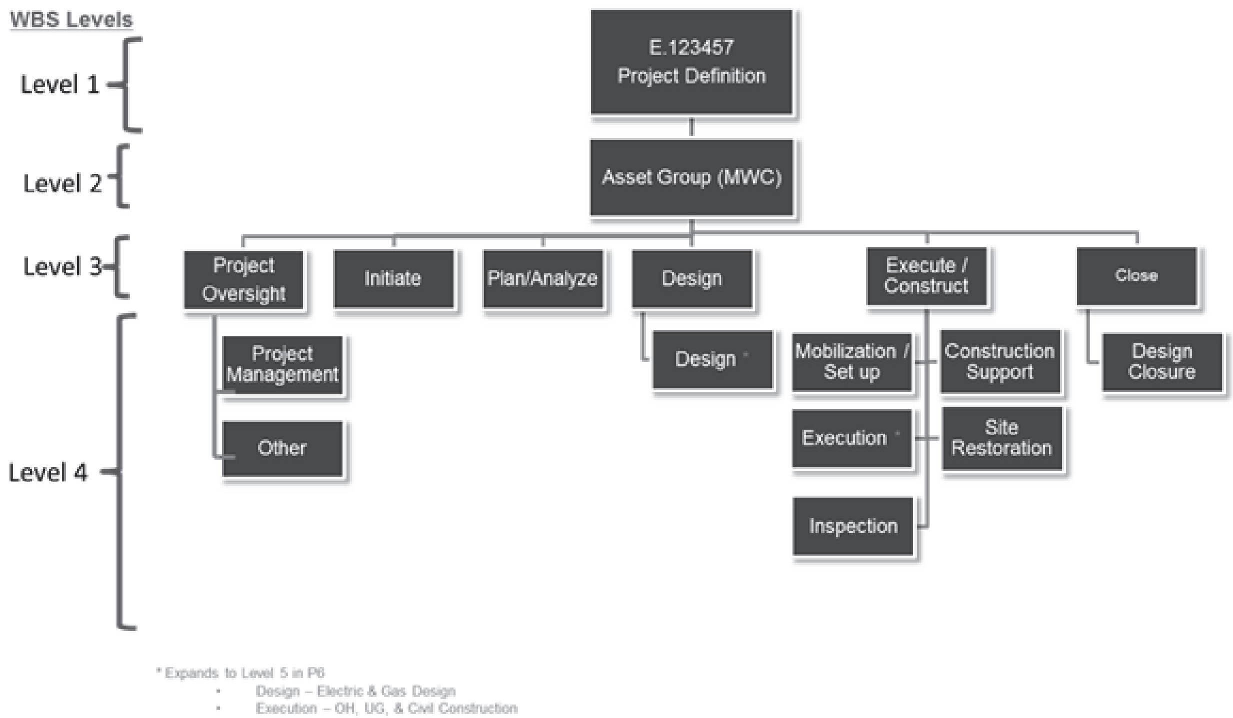
Figure 2 - PG&E Standard WBS



2.2 For Governance Threshold 4 projects, FAs may use the Reduced WBS depicted in Figure 3, “Reduced WBS” if the Expected Case if less than $5 Million. Applies only to SPSI managed projects.

1. All the requirements for Step 2.1 must be maintained with the Reduced WBS.

Figure 3 - Reduced WBS



2.3 FAs may use the 1 to Many (1:M) Order Structure if the project requires a high volume of Planning Orders and Plant Maintenance (PM) Orders AND if utilizing the Standard 1 to 1 Order Structure (i.e., One Planning Order to one PM Order) would add an excessive administrative burden to create, maintain, and manage the orders. Applies only to SPSI managed projects.

1. All the requirements for Step 2.1 except for substep 2.1.9 (WBS numbering scheme) must be maintained when utilizing the 1:M Order Structure (SEE Appendix H, “One to Many (1:M) Order Structure” for additional guidelines).

2.4 Plant Maintenance (PM) Orders with Operational Account Assignment

1. The operations associated with PM orders must be used to define level 5 elements of the WBS (SEE Appendix B, "Example FA Operation Codes").

2. FA-specific operations must represent the scope of work separated into manageable parts that correspond to project deliverables.

3. The additional levels must be in a hierarchical structure that maps back to level 4 and follows the same numbering system for levels and elements as used for levels 1 to 4.

4. The fully developed WBS must have as many levels beyond level 4 as is necessary to accurately estimate the full scope of work.

2.5 WBS Dictionary

1. FAs must develop a Standard WBS Dictionary that describes each of the work elements and levels below WBS level 4 (Work Summary).

2. The WBS Dictionary must be a single document used for all projects within a given FA.

3. FAs must use the elements in the WBS in a consistent and repeatable fashion for all projects.

4. Attributes of the WBS Dictionary must include:

   a. The end result or expected work product

   b. Units of measure

5. FAs must use the EPG WBS Dictionary for WBS levels 1 – 4, SEE Appendix A, "WBS Dictionary".

6. Once the additional levels and associated WBS Dictionary are developed, they must be approved by the EPGO and placed under revision control.

2.6 Relationships between WBS Level 2, Major Work Category (MWC), Planning Order, and Plant Maintenance (PM) Order:

1. The WBS must be designed such that there is a one to one relationship between the below listed key elements, REFER to Figure 4, “WBS One-to-One Order Requirements”:

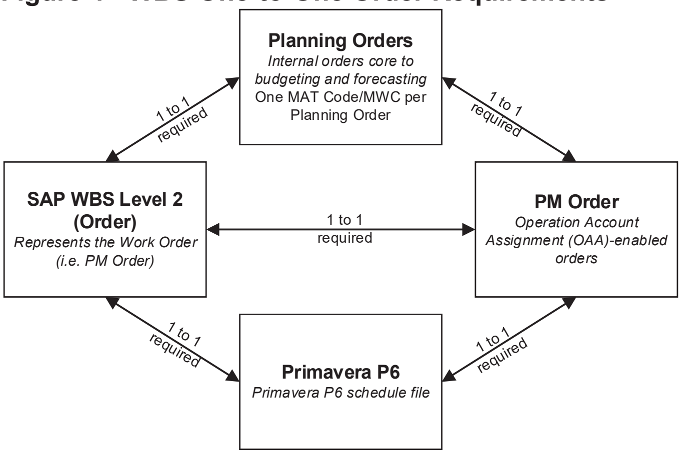
   a. A Planning Order (PO) and WBS Level 2 Major Work Category (MWC)

   b. WBS Level 2 MWC and Primavera P6 Schedule

   c. Primavera P6 Schedule and a Plant Maintenance (PM) Order

   d. Planning Order (PO) to Plant Maintenance (PM) Order

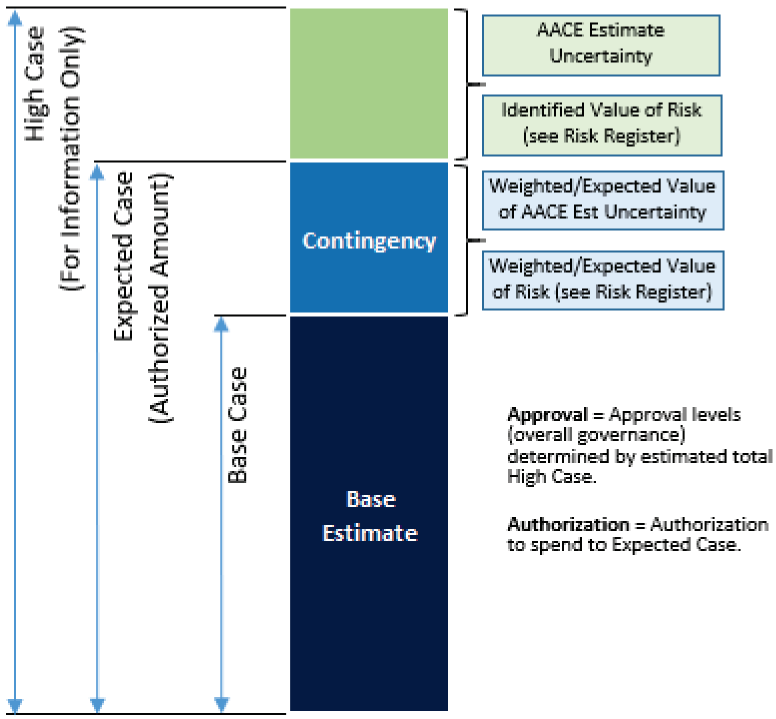
Figure 4 - WBS One-to-One Order Requirements



3 Project Cost Estimating

3.1 The project cost estimate must comprise the following items shown in Figure 5, "PG&E Estimate Components"

Figure 5 - PG&E Estimate Components



3.2 AACE Cost Estimate Classification System

1. FAs must define and implement an AACE Cost Estimate Classification System to align with the requirements in Table 1. The design of the AACE Estimate Classification System must be based on the appropriate AACE Recommended Practices listed in section Developmental References.

Table 1 - Estimate Classification System

AACE Cost Estimate Class	Maturity level of project definition expressed as % of complete definition	Typical Estimating Methods
Class 5	0% to 2%	Probabilistic: e.g., Top down, historical, parametric, analogous, capacity factored
Class 4	1% to 15%	Primarily Probabilistic: e.g., Equipment factored, parametric modelling
Class 3	10% to 40%	Probabilistic/Deterministic: e.g., Semi-detailed unit costs, quantity take-offs.
Class 2	30% to 75%	Primarily Deterministic: e.g., Bottom up, detailed unit costs, limited take-offs.
Class 1	65% to 100%	Deterministic: e.g., Bottom up, detailed unit costs.

2. The Estimate Classification System must define the maturity level of project deliverables based on typical criteria required to achieve a specific estimate classification, SEE Appendix C, "Estimate Classification".

   a. The AACE Estimate Classification System must have a set of deliverables for a project estimate to be classified at a specific AACE Estimate Class.

      (1) The set of deliverables must be split into required and optional.

      (2) If all of the deliverables for a specific class are not complete, the project must remain classified at the lower level until all items are complete.

3.3 Estimate Phase Gate application

1. FAs must align the development of each AACE Cost Estimate Class to Phase Gate as depicted in Table 2, “Estimate Phase Gate Application”.

Table 2 - Estimate Phase Gate Application

Project Governance Threshold	Phase Gate 1	Phase Gate 2	Phase Gate 3
4	Class 5	**Class 2 or Class 3** Depending on FA selection for Full Authorization	
3, 2 & 1	Class 5	Class 3 or 4	Class 2 or 3

3.4 Estimate Development

1. In accordance with Table 2, "Estimate Phase Gate Application" above, FAs must perform all the below activities during the development of each Estimate Class:

   a. Similar steps must be used in the development of each estimate, with the level of inputs and detail increasing as the project progresses from Phase Gate 1 to Phase Gate 3.

   b. Activities are not normally sequential and may be iterative.

   c. Activities may be combined into a single step depending on the specific process being used.

2. Quantify the Scope

   a. FAs must collect and evaluate the current documented scope basis and defining technical deliverables as key inputs into the estimate.

   b. Scope documents must first be quantified (e.g., take-off) in terms or formats required to add cost factors by the necessary units/parameters.

   c. The project specific scope must be assigned to the appropriate WBS elements.

   d. Indirect costs must be assigned to a project's unburdened cost in accordance with the Enterprise Cost Model (e.g., project management, home-office, engineering/design/management not accounted as direct cost).

3. Cost and resource load the scope

   a. The quantifiable areas of scope on the project must have an associated cost factor attributed to the labor, material, equipment, contract, or other attribute required to execute that portion of the scope.

   b. FAs must have a process to quantify cost for each scope attribute.

c. Costs must be assessed for project and scope specific conditions that may include waste, spoilage allowance, accuracy of measurement (e.g., take-off) allowance, specification, function, or content difference.

4. Incorporate impact of risk and AACE Uncertainty Factor

   a. SEE Subsection 5, "Risk Management".

5. Cash flow for the estimate

   a. For Estimate Classes 1, 2 and 3, the estimate must be time-phased in accordance with the schedule and must address monthly cash flow and cost constraints.

6. Document the estimate

   a. Estimates must be documented. Documentation requirements vary by Governance Threshold. SEE Step 3.5, "Basis of Estimate".

7. Develop the Job Estimate

   a. The Job Estimate and Settlement Rules must be completed in accordance with FIN-3805S, "Capital Job Estimate Standard" by Phase Gate 3 or at full project authorization.

8. Establish Earning Rules

   a. FAs must define Earned Value Earning Rules in accordance with the guidance provided in Appendix F, "Earned Value Earning Rules" and aligned with the PMI Standard Practice for Earned Value Management.

3.5 Basis of Estimate

1. For Governance Threshold 1 and 2 projects, FAs must prepare and maintain a Basis of Estimate (BOE) to support Phase Gate 2 and Phase Gate 3 approvals (SEE Appendix E, "Basis of Estimate Report").

3.6 Estimate validation

1. For Governance Threshold 1 projects, a check estimate must be performed prior to Board of Directors review at Phase Gate 2 and prior to execution at Phase Gate 3.

2. Check estimates must be based on recommendations outlined in AACEI Recommended Practice 31R-03 section "Reviewing Estimates Prepared by Others".

3. The check estimate must be validated against the Basis of Estimate to allow the FA to understand any difference in the key inputs and processes used to develop the estimate.

4. For all check estimates, whether internal or external, independence from the project must be a key consideration to obtain objective, unbiased input.

    a. Those preparing the estimate validation should be reasonably free from undue influence by the stakeholders, i.e., their pay or career is not primarily determined by the recipient of the estimate.

3.7 Project cost Records

1. FAs must include the final project cost and associated documents used to support the estimate's development as part of the project's cost records.

    a. The Basis of Estimate (BOE) must be included in the project cost records for Governance Threshold 1 and 2 projects.

    b. FAs must store project cost records in accordance with GOV-7101S, "Enterprise Records and Information Management Standard".

4 Project Cost Baseline

4.1 FAs must define an initial Project Cost Baseline to reflect the Expected Case to be included within the approved business case (or approved proxy) at Phase Gate 2 (not required for Governance Threshold 4 projects).

4.2 The Project Cost Baseline must reflect the Expected Case shown in the business case submitted at Phase Gates 2 and/or Phase Gate 3 (depending on Governance Threshold).

1. The Project Cost Baseline must be the cost basis against which the cost performance of the project is measured.

2. Governance Threshold 4 projects are not required to define a Project Cost Baseline until Phase Gate 3.

4.3 For each Project Cost Baseline update, the High Case, Expected Case, Base Estimate, Contingency, and the amount between Expected Case and High Case must be captured in the Enterprise Project Governance tool or other EPG approved tool.

4.4 For each Project Cost Baseline update, the project must revise the monthly cash flow for the whole project.

4.5 Changes to the Project Cost Baseline must be in accordance with the PM-1012S, "Integrated Change Control Standard".

5 Risk Management

5.1 Risk Identification

1. Project Specific Risk Identification

   a. FAs must establish a process to plan, assess, treat, and control the risks on projects.

   b. FA risk process requirements must vary based on Governance Thresholds.

      - For example, for Governance Threshold 4 projects, FAs may identify the typical risks associated with work in a specific MWC or MAT. However, the FA must not use this to apply an arbitrary cost multiplier to determine Contingency or the amount between Expected Case and High Case.

   c. Risks must be identified in all phases of the project lifecycle.

   d. For Governance Threshold 1 and 2 projects, FAs must hold a project risk identification workshop or a risk kick-off meeting prior to development of a project's Business Case.

   e. A Risk Register must be prepared as an output of the risk identification process (SEE Appendix D, "Risk Management" for an example Risk Register template).

   f. Any changes to a project submitted and approved through ICC must be assessed for risk and added to the Risk Register as necessary, if not previously included (SEE PM-1012S, "Integrated Change Control Standard").

   g. Risks must be reviewed, validated, and closed on an ongoing basis as defined by the FA.

   h. FA procedures must require that Risk Owners develop response plans for each risk.

   i. All risks must remain in the Risk Register throughout the life of the project, even if they are deactivated, or if they materialize into actual issues or benefits, so that the entire evolution of all the risks is captured.

   j. FAs wishing to analyze and report risk at a portfolio level must use Primavera P6 / Enterprise Project Governance Tools or other EPG approved tool.

   k. For Governance Threshold 1 and 2 programs, the risk register for each project must use a tool specified by Program Management Leadership and approved by EPG, which enables risk data to be consistently aggregated for the program.

5.2 Contingency Determination

1. Contingency, which is inclusive of the following elements, must be added to the Base Estimate to determine the value for the Expected Case:

   a. Weighted/Expected Value of AACE Estimate Uncertainty

   b. Weighted/Expected Value of Risks

2. The Expected Value of the Risk portion of Contingency must reflect the probabilistic determination of identified risks.

   a. Each risk in a project risk register must be assigned an impact (monetary) value should the risk occur.

   b. Each risk in the project risk register must assign a probability (chance of occurrence) that the risk will materialize.

   c. The impact value multiplied by the probability (chance of occurrence) provides the expected value of risk for each individual item.

   d. The expected value of risk for each individual item:

$$Weighted/Expected\ Value\ of\ Risk = (chance\ of\ occurrence) \times (impact\ value)$$

   e. The sum of all Expected Risks on the risk register must be included within Contingency:

$$Project\ Weighted/Expected\ Value\ of\ Risk = \sum All\ Weighted/Expected\ Value\ of\ Risks\ on\ a\ project$$

Table 3 - Complexity Factors

Estimate Class	Low Complexity		High Complexity	
	Weighted/Expected Value of AACE Estimate Uncertainty	Total Value of AACE Estimate Uncertainty	Weighted/Expected Value of AACE Estimate Uncertainty	Total Value of AACE Estimate Uncertainty
Class 5	10%	20%	70%	100%
Class 4	5%	15%	15%	50%
Class 3	5%	5%	10%	30%
Class 2	0%	5%	5%	20%
Class 1	0%	3%	0%	10%

3. For governance threshold projects 3 and 4, the AACE Estimate Uncertainty factor from Table 3 must be based on the systemic risk profile of the project (i.e., the level of complexity and/or risk associated with the project) as defined in Scalability in PM-1010S, “Project Management Governance Standard”. Within Contingency, AACE Risk is a major systemic risk factor.

a. Governance threshold projects 1 and 2 must categorize their projects as high complexity.

5.3 Determination of Amount Between Expected Case and High Case

1. The amount between Expected Case and High Case must be added to the Expected Case Estimate to reflect the following elements:

   a. The AACE Estimate Uncertainty

   b. The Identified Risk

2. The AACE Estimate Uncertainty must correspond to the same complexity (high or low) chosen for the determination of Contingency.

3. FAs must add the Identified Risk, which is the difference between the dollar value of the full impact of identified project risks and the total value of Expected Risks:

$$Identified\ Risk = \sum All\ Risk\ Impacts - \sum All\ Expected\ Risks$$

5.4 Alternative Risk Analysis methods

1. If an FA utilizes an alternative risk analysis method, such as Monte Carlo Simulation, the FA must obtain approval from the EPGO.

6 Cost Control

6.1 Cost Validation

1. All actual costs must be reviewed for accuracy by the project team.

2. FAs must evaluate work performed on the project to date to ensure actuals reflect work performed.

6.2 Contingency Management

1. Projects must maintain a log to track all Contingency usage, including the amount requested and/or approved and an explanation.

6.3 Actual Cost

1. All charges to the project must be charged to Operations (WBS level 5 and below) that rolls up to the appropriate WBS level 4 elements.

2. A Goods Receipt must be created for work performed or products received in the same month the work is performed (accrual accounting).

3. The Goods Receipt amount must be charged to the appropriate operational WBS (WBS level 5 and below).

4. The creation of the Goods Receipt must happen independently of receiving or paying an invoice.

5. Committed Cost must be recorded to Operations (WBS level 5 and below) that rolls up to the appropriate WBS level 4 elements.

6. Actual Cost plus Committed Cost must not exceed the authorized amount at any time during the life of a project from initiation to close.

6.4 Monthly Cash Flow Projections

1. FAs must maintain a projected monthly cash flow for the project life cycle.

2. Projects must provide a monthly cash flow for the Base Estimate at the time of authorization at Phase Gate 2, and for each subsequent authorization and/or Project Cost Baseline revision.

3. The cash flow projection must be consistent with the project schedule.

6.5 Project Cost Analysis

1. On a monthly basis a project cost analysis must be performed that calculates the following and enters the data into the Enterprise Project Governance tool or other EPG approved tool:

a. Estimate at Completion: The cost projected at the completion of the project without Contingency.

b. For Governance Threshold 1, 2 and 3 projects that are between Phase Gate 2 and Phase Gate 3, Estimate at Completion (EAC) must also be calculated to complete the work to get to Phase Gate 3.

c. For Governance Threshold 1 and 2 projects, earned value must be calculated on a monthly basis for each level 4 element in the WBS by using Earning Rules (SEE Substep 3.4.8).

6.6 Following the definition of the Project Cost Baseline (SEE Subsection 4, "Project Cost Baseline"), FAs must capture the following data elements at least monthly in Enterprise PM Tools/EPG approved tool until Phase Gate 5 Project Close:

1. Actual Costs
2. Committed Costs
3. An assessment of cost performance and anticipated ability to meet project cost objectives
4. Current / Authorized Amount (i.e., approved funding)
5. Spend to date
6. Current year budget
7. Year to date total spend
8. Current year forecast
9. Variance Analysis
10. Cost impacts from approved change orders

7 Monitoring and Compliance

7.1 The FAs must establish a monitoring and compliance program to validate their procedures are operating in accordance with this standard, referenced standards, and associated FA procedures.

END of Requirements

DEFINITIONS

REFER TO PM-1510, "Project Management Glossary"

IMPLEMENTATION RESPONSIBILITIES

N/A

GOVERNING DOCUMENT

- PM-01, "Project Policy"
- PM-1010S, "Project Management Governance (Approvals and Authorizations) Standard"

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Records and Information Management:

PG&E records are company assets that must be managed with integrity to ensure authenticity and reliability. Each Functional Area (FA) must manage Records and Information in accordance with the Enterprise Records and Information (ERIM) Policy, Standards and Enterprise Records Retention Schedule (ERRS). Each Functional Area (FA) is also responsible for ensuring records are complete, accurate, verifiable and can be retrieved upon request. Refer to GOV-7101S, "Enterprise Records and Information Management Standard" for further records management guidance or contact ERIM at Enterprise_RIM@pge.com.

REFERENCE DOCUMENTS

Developmental References:

- AACEI Total Cost Management Framework, Second Edition
- AACEI RP 18R-97: Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries
- AACEI RP 20R-98: Project Code of Accounts
- AACEI RP 31R-03: Reviewing, Validating, and Documenting the Estimate

- AACEI RP 33R-15: Developing the Project Work Breakdown Structure
- AACEI RP 34-05: Basis of Estimate
- AACEI RP 55R-09: Analyzing S-Curves
- AACEI RP 80R-13: Estimate at Completion (EAC)
- AACEI RP 82R-13: Earned Value Management (EVM) Overview and Recommended Practices Consistent with EIA-748-C
- AACEI RP 86R-14: Variance Analysis Reporting
- Project Management Institute (PMI) Standard Practice for Earned Value Management
- Project Management Institute (PMI) Practice Standard for Project Estimating

Supplemental References:

- PM-1001P-06, "Enterprise Project Governance Guidance Document Exception Request Procedure".
- GOV-7101S, “Enterprise Records and Information Management Standard”
- GOV-2001P-01, “Guidance Document Development, Review, and Revision Procedure”
- PM-1012S, "Integrated Change Control Standard"
- PM-1001P-01, “Project and Program Authorization and Approval Procedure”
- FIN-3805S, “Capital Job Estimate Standard”
- RISK-5001S, “Enterprise and Operational Risk Management Standard”
- RISK-5001P-01, “Enterprise and Operational Risk Management Procedure”.
- SAFE-1100S, “Serious Injury and Fatality (SIF) Standard”
- AACEI RP 18R-97: Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries
- AACEI RP 56R-08: Cost Estimate Classification System – As Applied for the Building and General Construction Industries
- AACEI RP 69R-12: Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industry
- AACEI RISK-3479: Variability in Accuracy Ranges: A Case Study in the US and Canadian Power Industry

APPENDICES

- Appendix A, "WBS Dictionary"
- Appendix B, "Example FA Operation Codes"
- Appendix C, "Estimate Classification"
- Appendix D, "Risk Management"
- Appendix E, "Basis of Estimate Template"
- Appendix F, "Earned Value Earning Rule"
- Appendix G, “WBS Attribute Table, Naming Conventions, Abbreviations”
- Appendix H, “One to Many (1:M) Order Structure”
- Appendix I, “Project Cost Estimate Example”

ATTACHMENTS

EPG Cost Standard Risk Register Template

DOCUMENT RECISION

Utility Procedure: PG-001, "Project Risk Management Procedure", Effective 06/01/13, Rev 1

Utility Standard: GM-1005S, “Project Cost Estimating Standard”, Effective 01/05/18, Rev 1

DOCUMENT APPROVER

Laura Shimamoto, Director, Enterprise Project Governance

DOCUMENT OWNER

Franklin Lyons, Principal Business Analyst, Enterprise Project Governance

DOCUMENT CONTACT

Franklin Lyons, Principal Business Analyst, Enterprise Project Governance

Project Cost Management Standard

REVISION NOTES

Where?	What Changed?
Entire Standard	Updated Document Approver
Entire Standard	Replaced Line of Business (LOB) with Functional Area (FA)
Entire Standard	Replaced Enterprise Project Management (EPM) with Enterprise Project Governance (EPG)
5.1.k	Additional guidance added in Risk Management Subsection 5: For Governance Threshold 1 and 2 programs, the risk register for each project must use a tool specified by Program Management Leadership and approved by EPG, which enables risk data to be consistently aggregated for the program.

Appendix A, WBS Dictionary
Page 1 of 2

A. SAP WBS Dictionary

1. Additional attributes that may be found in a WBS dictionary include:

   a Relationships and dependencies between elements of work

   b Optional elements

   c Assumptions or limitations

   d Technical specifications

   e Other supporting documents

2. The WBS dictionary must contain the same information for all WBS elements

Table 4 - Required WBS Dictionary Elements

SAP PS WBS Level 1 & 2	SAP PS WBS Description
Level 1	Represent the project at the highest level in SAP PS.
Level 2	SAP PS WBS Element representing the Major Work Category or Planning Order.
SAP PS WBS Level 3	**SAP PS WBS Description**
Project Oversight	Includes project overhead costs that do not align in a clean fashion to Project Phases.
Initiate	Includes creation of a project, preliminary project authorization, and creation of a work order in SAP PS and, where applicable, a Primavera P6 schedule.
Plan/Analyze	Includes development of cost, schedule, and resource estimates. Other ongoing activities triggered during this phase include risk and issue management and preliminary engineering assessments (enough design needs to occur for scope approval by the end of the phase).
Design	Includes development of the detailed engineering design, identification of scope/cost/ schedule baselines, and pre-construction activities. Other ongoing activities triggered during this phase include variance analysis/ change control, and performance reporting.
Execute/Construct	Includes mobilization, construction, testing, and other activities required to complete construction.
Close	Includes administrative and financial closeout of a project and project documentation.

Appendix A, WBS Dictionary
Page 2 of 2

SAP PS WBS Level 4 Description	SAP PS WBS Description
Project Management	Includes the activities associated with managing a project from initiation to close out. Resources such as Project Managers, PCA's and Schedulers would be aligned to this SAP PS WBS Level 4 Element.
Other	Includes activities not identified or defined by the other WBS Level 4 descriptions.
Project Set Up	Includes activities needed to create a project and include it in annual budgets and long-term plans.
Scoping	Includes activities in the Initiate Phase for engineering and planning to develop a project definition and Class 5 estimate.
Land Survey	Includes activities related to taking a position of the project location or surrounding area.
Scope Development	Includes activities needed to define a project scope to a level of detail that allows for a Class 4 Estimate to be developed.
Environmental Management	Includes activities necessary for environmental permitting and other environmental requirements on a project.
Land Management	Includes activities related to managing the land permitting, inspections and code enforcement for a project.
Design	Includes activities related to detailed design of a project.
Encroachment Permitting	Includes activities related to the placement of encroachments within, under, or over the State highway rights of way
Ministerial Permitting	If applicable, includes activities needed for complying with and obtaining a permit for meeting standards associated with zoning ordinances.
Environmental Compliance	Includes activities necessary to meet environmental standards, including, but not limited to storm water pollution prevention.
Natural Resource Management	Includes activities related to managing water, soil, plant and animal implications on a project.
Mobilization/Set-up	Includes activities associated with getting resources on site and getting a project site set up to begin execution/construction.
Execution	Includes activities associated with construction/completion of the work defined in the project plan.
Inspection	Includes activities for on-site reviews and inspections during execution
Test/Commission	Includes activities for testing and commissioning equipment and systems
Construction Support	Includes activities related to health & safety, construction administration and other supporting work.
Site Restoration	Includes activities necessary to return a project site back to an operational standard
Environmental Closure	Includes activities for obtaining approval for closure of permits and other environmental requirements.
Design Closure	Includes activities for completing and approving design drawings and as-built records

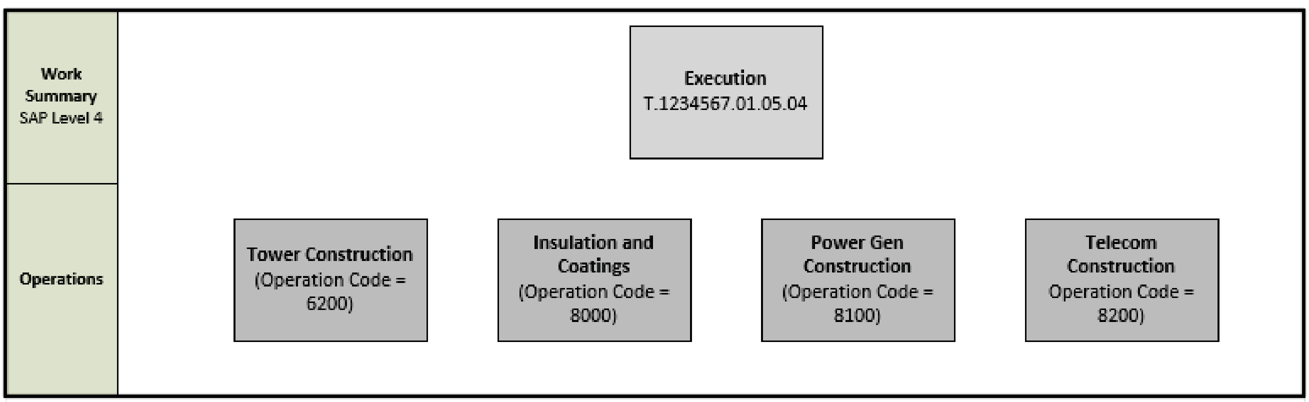
Appendix B, Functional Area (FA) Operation Codes
Page 1 of 1

A. FAs may develop a code of accounts similar to the examples provided below

1. FAs must develop code of accounts for as many levels to require to accurately estimate the full scope of work.

2. Operations should be used for scope management and refined estimating. If work is performed by a third party/vendor, scope should be divided into necessary parts as applicable to manage the contract and associated schedule of value.

Figure 6 - Example FA Operations Codes



Appendix C, Estimate Classification
Page 1 of 1

A. Example Estimate Classification System

1. The AACE Classes are driven by generic risk management principles in 17R-97, which provides cross-industry consistency.

   a For example, Class 3 reflects the level of definition at which research shows there is little further risk reduction from doing more definition.

   b Class 4 is the level of definition where one can economically select a single scope option, but with measurable scope risk remaining.

2. Determination of Cost Estimate Class

   a Class 5 Estimate

      (1) Description: Class 5 project estimates correspond to projects in the early concept and planning phase, often before a project team has been assigned. Class 5 estimates are prepared based on limited information (e.g., a very high-level investment objective provided by a sponsor) and subsequently have a wide range of potential outcomes.

      (2) Typical Inputs: Facility type, capacity, location, and investment objectives.

      (3) End Usage: Advanced Authorization (AA).

      (4) Estimating Methodology: Class 5 estimates generally use probabilistic estimating methods such as cost/capacity curves and factors, historical benchmarks, and other parametric techniques.

   b Class 4 Estimate

      (1) Description: Class 4 estimates are based on a selected asset alternative and are prepared with limited scope information and have a wide range of potential outcomes. Execution strategy alternatives (e.g., routing/siting, contracting strategy) are typically not yet selected.

      (2) Typical Inputs: <15% overall engineering design, feasibility design for several alternative layouts/routes, facility capacity, preliminary one-line diagrams, and comprehensive user requirements

      (3) Estimating Methodology: Class 4 estimates generally use probabilistic estimating methods, including equipment factors, gross unit costs/ratios, and other parametric modeling.

Appendix C, Estimate Classification
Page 2 of 3

c Class 3 Estimate

(1) Description: Class 3 estimates are based on a detailed scope of work, execution strategy, and preliminary engineering design.

(2) Typical Inputs: 30-60% overall engineering design, e.g., contracting/procurement strategy, substantially complete geotechnical investigations, preliminary earthwork drawings for excavation, complete one line diagrams, equipment performance specifications.

(3) End Usage: Phase Gate 2 Authorization (SEE PM-1010S, “Project Management Governance Standard”), Initial Project Cost Baseline. Any changes after Phase Gate 2 must meet the requirements of PM-1012S, "Integrated Change Control Standard". Note: Phase Gate 2 requirements do not apply to Governance Threshold 4 projects.

(4) Estimating Methodology: Class 3 estimates involve more deterministic estimating methods than probabilistic methods. They usually involve the predominant use of unit cost line items, although these may be at an assembly level of detail rather than individual components. The estimate should be based on scope of work documents as well as expected permit costs. Factoring and other probabilistic methods may be used to estimate less-significant areas of the project.

(5) For Governance Threshold 1 projects, a Class 3 estimate, at a minimum, is required for authorization by the PG&E Board of Directors, SEE PM-1010S, “Project Management Governance Standard.

d Class 2 Estimate

(1) Description: Class 2 estimates are based on detailed engineering designs and execution plans.

(2) Typical Inputs: 60-90% engineering design, detailed resource plans, critical path execution schedules, and vendor quotes for substantial portions of equipment, material, and construction services.

(3) End Usage: Phase 3 Authorization (SEE PM-1010S, “Project Management Governance Standard"), project reauthorization, change orders, updated Project Cost Baseline.

(4) Estimating Methodology: Class 2 estimates generally involve a high degree of deterministic estimating methods, including quantity takeoff and detailed resource/contracting plans. Class 2 estimates are prepared in detail and often involve numerous unit cost line items.

Appendix C, Estimate Classification
Page 3 of 3

e Class 1 Estimate

(1) Description: A Class 1 estimate represents the highest level of estimating certainty. It assumes 100% of engineering is complete, all work is under contract, and enough progress has been made to extrapolate performance trends.

(2) Typical Inputs: 100% engineering design, awarded contracts, execution progress and performance measures, detailed execution and commissioning plans.

(3) End Usage: Reauthorization, change orders

(4) Estimating Methodology: Class 1 estimates generally involve the highest degree of deterministic estimating methods and require a significant amount of effort. Class 1 estimates are prepared in great detail and are therefore usually performed on only the most important or critical areas of the project. Items in the estimates are usually based on bids based on final design specifications or accurate unit cost line items based on actual design quantities. In cases where construction is already underway, a Class 1 estimate may be based on earned value management metrics and performance trending analysis.

Appendix D Risk Management
Page 1 of 3

A. Recommendations for Risk Management (Plan, Assess, Treat, Control)

1. Plan: Develop a plan to manage risks for each project.

   a For example, utilize a Risk Register to track and manage risks: EPG Cost Standard Risk Register Template

2. Assess: Identify risks and perform analysis.

   a Commonly used risk identification techniques include:

      (1) Brainstorming: Generate potential risks through free-form discussion or structured interviewing, then categorize by risk type for further definition.

      (2) Checklists: Use a list of commonly occurring risks that was developed based on knowledge that has accumulated from previous projects within the FA or from other FAs.

      (3) Root Cause Analysis: Identify a problem and discover the underlying causes, which can then lead to the development of preventative actions or potential risks.

      (4) Lessons Learned and Knowledge Transfer: Obtain risk-related knowledge from lessons learned. Review the Risk Registers from previous projects.

   b Qualitative Risk Analysis (Risk Ranking)

      (1) Qualitative Risk Analysis is a method to rank risks according to criticality and significance to a project.

      (2) Estimated probabilities and impact ratings for each of the identified risks must be developed. At a minimum, a 3x3 matrix must be used with High / Medium / Low values as shown below. A matrix higher than a 5x5 may not be used.

Project Cost Management Standard

Appendix D, Risk Management

Figure 7 - Risk Score Matrix (3x3)

Probability	High	Low	High	High
	Medium	Low	Medium	High
	Low	Low	Low	High
		Low	Medium	High

(3) The Risk Register (Excel, Primavera P6, or other FA specific method) must include the following information:

- Probability: Level of probability that the risk will transform into an issue or benefit.
- Cost and Schedule Impacts: Level of impact the risk can have on the total project cost or schedule.
- Risk Score: The Risk Register must calculate an overall Risk Score. The overall Risk Score is equal to the Probability (P), plus the Impact to Cost (IC), plus the Impact to Schedule (IS), i.e., the Risk Score = P + IC + IS. A Red, Amber, or Green (RAG) Heatmap status must be assigned to each risk.

3. Treat: Identify Risk Owners and Risk Response

a Assign a Risk Owner for each risk.

b Develop a response strategy for each risk: Accept, Avoid, Reduce, or Transfer.

Appendix D, Risk Management
Page 3 of 3

4. Control: Monitor and Control Risk

   a New risks must be added to the Risk Register.

   b Risks must be reviewed on a periodic basis. Significant changes to the project, for example a scope change, must include a risk review.

   c All risks must remain in the Risk Register for the duration of the project to ensure the entire evolution of the risks is captured.

Appendix E, Basis of Estimate Report
Page 1 of 2

A. Basis of Estimate (BOE) Report

1. Threshold 1 and 2 projects must develop a Basis of Estimate Report

2. Threshold 3 and 4 projects should develop a Basis of Estimate Report

3. Basis of Estimate Report should:

   a Be factually complete and concise

   b Be able to support facts and findings

   c Identify estimating team members and their roles

   d Describe the tools (including software), techniques, estimating methodology, and data used to develop the cost estimate

   e Identify other projects that were referenced and/or benchmarked during estimate preparation.

   f Be prepared in parallel with the cost estimate

   g Qualify any rates or factors (such as escalation factors) that are referenced either in the cost estimate or BOE

   h Record of all key communications made during estimate preparation

   i List all documents used to prepare the estimate

   j Communicate the estimator’s knowledge of the project by demonstrating an understanding of scope and schedule as it relates to cost

   k Establish the context of the estimate, and support estimate review and validation.

   l Act as a source of support during dispute resolutions

4. Recommended content for the Basis of Estimate Report:

   a Cover Page: Comprising project name, estimate classification, estimator and date completed.

   b Purpose of Estimate: A brief and concise description about the project objective(s), location and overall timing of the project. The reason for the developing the estimate should be provided.

Appendix E, Basis of Estimate Report
Page 2 of 2

c Scope Description: A description of the scope of work for each major component of the project, which should be aligned to the project's work breakdown structure. Identify any major equipment/component and/or significant materials.

d Overall Cost: A summary of estimated project cost including the high and low ranges based on estimate class, with expected range of accuracy. Project cost should be summarized by summarized by initiate phase, plan/analyze phase, design phase, Construction phase and close phase.

e Estimate History: A short description of the history of the estimate(s) generated to date for the project at a summary level.

f Estimate Methodology: A description of the primary estimating methodology used to prepare the cost estimate. This should include documentation of the use of cost resources, historical data and project benchmarking.

g Source Documents: A detailed list/description of the documents used to generate the estimate (e.g., drawings, specifications, etc.) including revision numbers and issue dates.

h Escalation Rate(s): A description of the escalation calculation including the assumed start, end and mid-point dates of construction, the annual escalation rate used and the resulting total escalation.

i Cost Basis: A description of the methods, including contract delivery, and resources used for determining all material, labor and subcontract pricing to include pricing sources for equipment, bulk material, labor hours, taxes, influence of local market conditions, etc.

j Assumptions: A detailed list of assumptions used to build the estimate.

k Excluded Costs: A list of costs not included in the estimate.

l Allowances: A list of allowances made for known requirements not yet specified in the source documents. Include the basis for calculating the cost (e.g., X percent of net total).

m Contingency: An explanation of the Contingency amount used in the estimate, what it's for and how it was derived (e.g., high probability risks)

n Exceptions: A list of any variances to Utility standard(s) or significant deviations from the project and/or engineering deliverables normally required for the applicable class of estimate.

Appendix F, Earned Value Earning Rules
Page 1 of 2

A. Guidance for setting up Earned Value (Governance Threshold 1 & 2 projects only)

1. Earned Value is a measure of the work performed on a project. The implementation of Earned Value requires a pre-defined method of measurement for the project progress, also known as Earning Rules.

2. To accommodate the different types of work performed on a project, there are a number of acceptable methods that FAs may use to measure progress.

3. Earned Value earning rules must be defined prior to starting the project using one of the options below:

   a Milestone based (weighted milestones)

      (1) The measurement of the work package is divided in measurable segments, each ending with a significant milestone.

      (2) A weighted value is assigned to the achievement of each milestone (e.g., Milestone 1 – 10%, Milestone 2 – 50%, Milestone 3 – 100%).

   b Percent Complete

      (1) An estimate of the percentage of the work complete is assessed at the end of each measurement period.

      (2) This method must be based on objective and quantifiable work completion.

      (3) There must be enough activities in the schedule to minimize EV inaccuracies., schedules EV accuracy is improved by breaking long duration activities into several short duration activities.

   c Physical Measurement (e.g., each, linear feet, square feet, etc.)

      (1) Measurement of work using units that can be explicitly related to the completion of work (e.g., number of towers erected, length of pipe laid).

   d Level of effort (must only be used for indirect work (e.g., project management or overheads))

      (1) Activities that do not directly produce defined end products that can be objectively measured.

      (2) Includes project management and other overhead activities that occur through the life of a project.

Appendix F, Earned Value Earning Rules
Page 2 of 2

(3) Usually measured by number of hours x billing (hourly) Rate against a predefined allocation for the project.

4. Once earning rules are established on a project, the rules must not be changed.

   a Any changes to the configuration of the earnings rules during a project must be approved by the EPGO. This may occur if earning rules were established before the full scope of the project was fully known.

5. FAs may define common earning rules by project/work type.

6. FAs must consider the following elements when deciding which type of earning rules to implement:

   a Characteristics of work (duration and measurability)

   b Requirements

   c Measurement Units (hours or other measurable units)

   d Risk

   e Level of accuracy to measure (cost, schedule, and performance)

Appendix G, WBS Attribute Table, Naming Conventions, Abbreviations
Page 1 of 4

A. Guidance for setting up a project in SAP Project Systems for use by Functional Areas

1. Figure 2 (SEE page 5) and Table 4 should be referenced when setting up a project in SAP Project Systems to verify the WBS is applied per the requirements of the PM-1015S, "Project Cost Management Standard."

2. The Standard WBS and approved variations can be found on the Enterprise Project Governance Office (EPGO) SharePoint Site:

   a Standard WBS

   b Reduced WBS

   c Environmental Remediation WBS

   d IT Standard WBS

   e IT Reduced WBS

3. SPSI WBS Naming Conventions

   a Requirements

      (1) Functional Areas must select the appropriate WBS structures based on the requirements Section 2 of the Project Cost Management Standard and Project Governance Standard. See WBS Attribute Matrix (SEE Figure 6, "WBS Attribute Matrix")

      (2) Any additional structures must be approved by the EPGO

      (3) Naming convention is based on ("FA – "WBS Structure Name") – See Attribute matrix for additional requirements

Appendix G, WBS Attribute Table, Naming Conventions, Abbreviations
Page 2 of 4

Table 5 - SPSI WBS Naming Conventions

Project Type SPSI Naming Convention	Description	Applicability (reference WBS Attribute Matrix for further detail)
ET-LPE	ET&S-Standard WBS Project-Expense	*All thresholds for ET&S Expense projects*
ET-LPC	ET&S-Standard WBS Project-Capital	*All thresholds for ET&S Capital projects*
ED-LPE	ED-Standard WBS Project-Expense	*All thresholds for ED Expense projects*
ED-LPC	ED-Standard WBS Project-Capital	*All thresholds for ED Capital projects*
ED-LPE1	ED-Standard WBS Project-Expense - 1:M	*All thresholds for ED Expense projects*
ED-LPC1	ED-Standard WBS Project-Capital - 1:M	*All thresholds for ED Capital projects*
ED-SPE1	ED-Reduced WBS Project-Expense - 1:M	*ED Governance Threshold 4 Expense projects only*
ED-SPC1	ED-Reduced WBS Project-Capital - 1:M	*ED Governance Threshold 4 Capital projects only*
GT-LPE	GT-Standard WBS Project-Expense	*All thresholds for GT Expense projects*
GT-LPC	GT-Standard WBS Project-Capital	*All thresholds for GT Capital projects*
GD-LPE	GD-Standard WBS Project-Expense	*All thresholds for GD Expense projects*
GD-LPC	GD-Standard WBS Project-Capital	*All thresholds for GD Capital projects*
ET-SPE	ET&S-Reduced WBS Project-Expense	ET&S *Governance Threshold 4 Expense projects only*
ET-SPC	ET&S-Reduced WBS Project-Capital	*ET&S Governance Threshold 4 Capital projects only*
ED-SPE	ED-Reduced WBS Project-Expense	*ED Governance Threshold 4 Expense projects only*
ED-SPC	ED-Reduced WBS Project-Capital	*ED Governance Threshold 4 Capital projects only*
GT-SPE	GT-Reduced WBS Project-Expense	*GT Governance Threshold 4 Expense projects only*
GT-SPC	GT-Reduced WBS Project-Capital	*GT Governance Threshold 4 Capital projects only*
GD-SPE	GD-Reduced WBS Project-Expense	*GD Governance Threshold 4 Expense projects only*
GD-SPC	GD-Reduced WBS Project-Capital	*GD Governance Threshold 4 Capital projects only*

Appendix G, WBS Attribute Table, Naming Conventions, Abbreviations
Page 3 of 4

Project Type SPSI Naming Convention	Description	**Applicability** (reference WBS Attribute Matrix for further detail)
IT-PJE	IT Standard WBS Project-Expense	*All thresholds for IT Expense projects*
IT-PJC	IT Standard WBS Project-Capital	*All thresholds for IT Capital projects*
IT-SPE	IT Reduced WBS Project-Expense	*IT Governance Threshold 4 Expense projects only*
IT-SPC	IT Reduced WBS Project-Capital	*IT Governance Threshold 4 Capital projects only*
IT-CO	IT-Core (Non-project)-Expense	*Specific IT work only*
IT-NP	IT-NP App Enhancement (Non- project)-Expense	*Specific IT work only*
IT-OM	IT-O&M (Non-project)-Expense	*Specific IT work only*
PF-LPE	PGEN Fossil - Standard WBS Project - Expense	*All thresholds for PGEN Fossil Expense projects*
PF-LPC	PGEN Fossil - Standard WBS Project - Capital	*All thresholds for PGEN Fossil Capital projects*
PH-LPE	PGEN Hydro - Standard WBS Project - Expense	*All thresholds for PGEN Hydro Expense projects*
PH-LPX	PGEN Hydro - Standard WBS Project - Capital	*All thresholds for PGEN Hydro Capital projects*

Project Cost Management Standard

Appendix G, WBS Attribute Table, Naming Conventions, Abbreviations
Page 4 of 4

Table 6 - WBS Attribute Matrix

WBS KEY	Name	Governance Threshold				LOBs									
		GT1 >$250M	GT2 >$25M	GT3 <$25M	GT4 <$25M	IT (K)	CRESS *(tbd)*	DCPP (D) Not Used	ET&S (T)	ED (E)	GT (N)	GD (G)	PGEN Fossil (F)	PGEN Hydro (H)	ER *(tbd)*
LPC or LPE	Standard WBS	Y	Y	Y	Y	N	N	N	Y	Y	Y	Y	Y	Y	N
SPC or SPE	Reduced WBS	N	N	N	Y	N	N	N	Y	Y	Y	Y	N	N	N
LPC1 or LPE1	Standard WBS-1:M	Y	Y	Y	Y	N	N	N	N	Y	N	N	N	N	N
SPC1 or SPE1	Reduced WBS-1:M	N	N	N	Y	N	N	N	N	Y	N	N	N	N	N
TBD	Remediation WBS	Y	Y	Y	Y	N	N	N	N	N	N	N	N	N	Y
IT-LPC or IT-LPE	IT Standard WBS	Y	Y	Y	Y	Y	N	N	N	N	N	N	N	N	N
IT-SPC or IT-SPE	IT Reduced WBS	N	N	N	Y	Y	N	N	N	N	N	N	N	N	N
IT-CO	IT Core (Non-project)	N/A	N/A	N/A	N/A	Y	N	N	N	N	N	N	N	N	N
IT-NP	IT NPAE (Non-project)	N/A	N/A	N/A	N/A	Y	N	N	N	N	N	N	N	N	N
IT-OM	IT O&M (Non-project)	N/A	N/A	N/A	N/A	Y	N	N	N	N	N	N	N	N	N

WBS KEY	Name	Allocation		Cost Limit			WBS Image
		Expense (E)	Capital (C)	Minimum Estimated Total High Case Amount	AACE Class 5 Maximum Base Estimate Limit (Low Complexity)	Estimated Total High Case Amount	
LPC or LPE	Standard WBS	Y	Y	>$1M	N/A	N/A	Standard WBS
SPC or SPE	Reduced WBS	Y	Y	>$1M	<$15M	$<25M	Reduced WBS
LPC1 or LPE1	Standard WBS-1:M	Y	Y	>$1M	N/A	N/A	Standard WBS-1:M
SPC1 or SPE1	Reduced WBS-1:M	Y	Y	>$1M	<$15M	$<25M	Reduced WBS-1:M
TBD	Remediation WBS	Y	Y	>$1M	N/A	N/A	Env Rem
IT-LPC or IT-LPE	IT Standard WBS	Y	Y	>$1M	N/A	N/A	IT Standard WBS
IT-SPC or IT-SPE	IT Reduced WBS	Y	Y	>$1M	<$15M	$<25M	IT Reduced WBS
IT-CO	IT Core (Non-project)	Y	N	N/A	N/A	N/A	IT Core WBS (Non-project, expense only)
IT-NP	IT NPAE (Non-project)	Y	N	N/A	N/A	N/A	IT Non-Project App Enhancement (Non-project, expense only)
IT-OM	IT O&M (Non-project)	Y	N	N/A	N/A	N/A	IT Operations & Maintenance (Non-project, expense only)

Appendix H, 1 to Many (1:M) Order Structure
Page 1 of 3

A. Guidance for utilizing the 1:M Order Structure for use by Functional Areas (FAs) for SPSI projects:

1. Subsection 2, Figure 2, "PG&E Standard WBS" (SEE Page 6) and Table 4, "Required WBS Dictionary Elements" should be referenced when setting up a project in SAP Project Systems to verify the applicable WBS and order structure per the requirements of the PM-101S, "Project Cost Management Standard."

2. Projects utilizing the 1:M Order Structure must use the appropriate levels, elements, and numbering scheme (as defined in this Standard) of the WBS Shown in Figure 8, "PG&E Standard WBS + 1:M Order Structure" (SEE page 42). Applies to SPSI managed projects.

3. The 1:M Order Structure and the established variations can be found on the Enterprise Project Governance Office (EPGO) SharePoint Site. 1:M Order structure must be approved and configured to be available for use.

   a 1: Many Order Structure

   b Standard WBS Utilizing 1:M Order Structure

   c Reduced WBS Utilizing 1:M Order Structure

4. 1:M Order Structure Application

   a Requirements

      (1) FAs may use the 1:M Order Structure if using the Standard 1 to 1 Order Structure (i.e., One Planning Order to one Plant Maintenance (PM) Order) creates an excessive administrative burden to the FA and/or project team to create, maintain, and manage the Planning Orders and PM Orders.

      (2) 1:M Order Structure may be utilized when the project requires a high volume of Planning Orders and PM Orders.

      (3) For Governance Threshold 4 projects, FAs may use 1:M Order Structure. Governance Threshold projects 3, 2, and 1 must receive approval by the FA Manager (PL1/PL2) and notify the Enterprise Project Governance Office (EPGO) before proceeding.

Appendix H, 1 to Many (1:M) Order Structure

5. SPSI WBS Naming Conventions

   a Requirements

      (1) Functional Areas (FAs) must select the appropriate WBS structures based on the requirements of the Project Cost Management Standard and the Project Governance Standard. See WBS Attribute Matrix (SEE Figure 7, "WBS Attribute Matrix")

      (2) Naming convention is based on ("FA – "WBS Structure Name") – See WBS Attribute matrix for additional requirements.

6. 1:M Order Structure Relationship between WBS Level 2, Major Work Category (MWC), Planning Order and Plant Maintenance (PM) Order:

   a The WBS utilizing the 1:M Order Structure must be designed such that there is the following relationship between the below listed key elements:

      (1) A Planning Order (PO) and WBS Level 2 Major Work Category (MWC)

      (2) WBS Level 2 MWC and Primavera P6 Schedule

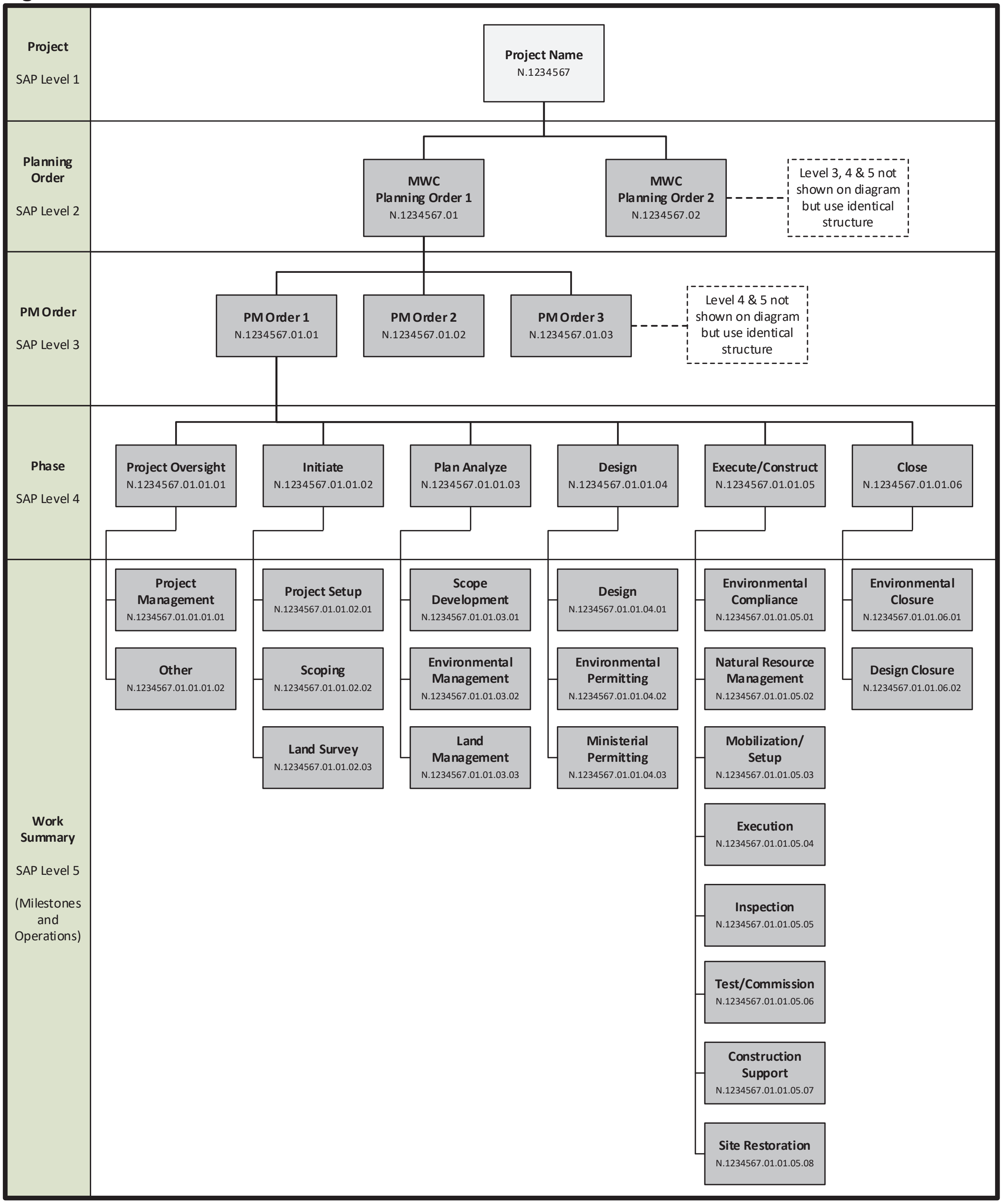
      (3) A Primavera P6 Schedule and a Plant Maintenance (PM) Order

      (4) One Planning Order (PO) to Multiple Plant Maintenance (PM) Orders

   b One Planning Order may have a maximum of ninety-nine (99) PM Orders tied to the Planning Order.

Appendix H, 1 to Many (1:M) Order Structure
Page 3 of 3

Figure 8 - PG&E Standard WBS + 1:M Order Structure



Appendix I, Project Cost Estimate Example

With a base estimate of $39.6M, the project is classified as an AACE Class 3, high complexity project with actuals of $2.5M, commitments of $0.5M, and the risk allowance table below:

Risk Allowance Table								
	Gate 1				Gate 2			
Risk #	Likelihood	Weight	Risk ($ M)	Weighted Risk ($M)	Likelihood	Weight	Risk ($ M)	Weighted Risk ($M)
1	M	0.5	$ 10.0	$ 5.0	L	0.2	$ 10.0	$ 2.0
2	L	0.2	$ 2.0	$ 0.4	L	0.2	$ 1.0	$ 0.2
3	M	0.5	$ 2.0	$ 1.0	L	0.2	$ 1.5	$ 0.3
4		-	$ -	$ -	L	0.2	$ 10.0	$ 2.0
5		-	$ -	$ -	L	0.2	$ 2.0	$ 0.4
Total			$ 14.0	$ 6.4			$ 24.5	$ 4.9

High Case Estimate Calculation:

High Case = Base Estimate + Total Identified Risk + Total AACE

Total Identified Risk = $14.0M + $24.5M = $38.5M

Total AACE = AACE Factor X (Base Estimate + Total Risk – Incurred Cost) = 30% X ($39.6M+38.5M $2.5M) = $22.7M

High Case = $39.6M + $38.5M + $22.7M = $100.7M

Expected Case Estimate Calculation:

Expected Case = Base Estimate + Expected Value of Risk + Expected AACE Uncertainty

Expected AACE Uncertainty = AACE Factor X Total AACE = 10% X $22.7M = $2.3M

Expected Value of Risk (Risk Register) = $6.4M + $4.9M = $11.3M

Expected Case = $39.6M + $11.3M + $2.3M = $53.1M

ATTACHMENT 10

AACE International Recommended Practice No. 69R-12

AACE International Recommended Practice No. 69R-12

COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE HYDROPOWER INDUSTRY

TCM Framework: 7.3 – Cost Estimating and Budgeting

Rev. January 25, 2013

Note: As AACE International Recommended Practices evolve over time, please refer to www.aacei.org for the latest revisions.

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COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE HYDROPOWER INDUSTRY

TCM Framework: 7.3 – Cost Estimating and Budgeting

January 25, 2013

PURPOSE

As a recommended practice of AACE International, the *Cost Estimate Classification System* provides guidelines for applying the general principles of estimate classification to project cost estimates (i.e., cost estimates that are used to evaluate, approve, and/or fund projects). The *Cost Estimate Classification System* maps the phases and stages of project cost estimating together with a generic project scope definition maturity and quality of inputs matrix, which can be applied across the hydropower industry.

This addendum to the generic recommended practice (17R-97) provides guidelines for applying the principles of estimate classification specifically to project estimates for engineering, procurement, and construction (EPC) or other contractual arrangements and execution venues, both for owners and service providers, and their related work in developing hydropower projects. This addendum supplements the generic recommended practice by providing:

- a section that further defines classification concepts as they apply to the hydropower industry and their unique differences to other industries
- a section on the regulatory requirements and resulting impacts that are specific to hydropower projects
- a chart that maps the extent and maturity of estimate input information (project definition deliverables) against the class of estimate.

As with the generic recommended practice, the intent of this addendum is to improve communications and consensus among all of the stakeholders involved with preparing, evaluating, and using project cost estimates specifically for the hydropower industry.

The overall purpose of this recommended practice is to provide the hydropower industry with a definition deliverable maturity matrix which is not covered in 17R-97. This RP provides an approximate representation and logical linage of the relationship of specific design input data and design deliverable maturity to the estimate accuracy and methodology used to produce the cost estimate.

The estimate accuracy range is driven by many other variables and risks, so the maturity and quality of the scope definition available at the time of the estimate is not the sole determinate of accuracy; risk analysis is required for that purpose.

This document is intended to provide a general guideline, not a standard. It is understood that each enterprise may have its own project and estimating processes and terminology, and may classify estimates in their own particular ways. This guideline provides a generic and generally acceptable classification system for the hydropower industry that can be used as a starting point for the basis of comparison. This RP should allow each user to better assess, define, and communicate their established and developed procedures and standards in light of generally-accepted cost engineering practice.

INTRODUCTION

For the purposes of this RP, the term "hydropower industry" is assumed to include private and public utilities involved with the production of electrical power, exclusive of transmission and distribution, using natural gravitational force of falling or flowing water, excluding tidal forces, to drive a turbine that powers a generator.

The common thread among private and public utilities (for the purpose of estimate classification) is their reliance on user requirements, statement of objectives, design reports (i.e. geotechnical investigations, sourcing borrow materials and hydraulic design/modeling) and/or environmental data collection and studies as primary scope defining documents. These documents are key deliverables in determining the degree of project definition, and thus the extent and maturity of estimate input information.

Cost estimates for hydropower facilities are typically composed of key features such as:

- Reservoir area preparation (e.g., clearing, removal of structures and earthmoving).
- River management (e.g., cofferdams, diversion channels or tunnels, sediment management plans, environmental monitoring programs).
- Principal structures (e.g., dams, dykes, intakes, penstocks, powerhouse(s), low level outlet(s), power tunnel(s), de-silting basin(s), and spillway structure(s)).
- Permanent infrastructure (e.g., access roads, railroads, bridges, offices, warehouse and housing).
- Temporary infrastructure (e.g., construction camp, site access roads, airport, workshops, construction power etc).
- Environmental mitigation features (e.g. fish ladder(s), water bypass and creation of new fish or wildlife habitat).
- Owner's costs (e.g., stakeholder involvement, licensing, studies and investigations, administration and overhead, catering.).

Some, but not all, of these features are unique to the hydropower industry.

Typical hydropower facilities may include: turbines, generators, exciters, governors, transformers, gates for intake, spillway and draft tubes, and supporting electrical, mechanical, telecom, protection, and control systems. The water storage reservoir is typically required to support the operations of the hydropower facility.

This RP does not specifically address cost estimate classification for other industries such as commercial building construction, environmental remediation, transportation infrastructure, process (oil & gas), "dry" processes such as assembly and manufacturing, mining and mineral processing, transmission and distribution of electricity, thermal, wind, solar, tidal and geothermal generation, "soft asset" production such as software development, and similar industries.

The cost estimates covered by this RP are primarily for engineering, procurement, and construction (EPC) work during implementation. Planning and regulatory compliance cost during the identification and definition phases of the project and final testing and commissioning at close-out is also covered under this RP. Operation and maintenance during the life of the hydropower facility are not addressed in this RP.

This RP reflects generally-accepted cost engineering practices and is based upon consolidated practices from the hydropower industry that covers its major production facilities.

COST ESTIMATE CLASSIFICATION MATRIX FOR THE HYDROPOWER INDUSTRY

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

Table 1 – Cost Estimate Classification Matrix for the Hydropower Industry

Table 1 provides a summary of the characteristics of the five estimate classes. The maturity level of project definition is the sole determining (i.e., primary) characteristic of a corresponding Class. In Table 1, the maturity is roughly indicated by a % of complete definition; however, it is the maturity of the defining deliverables that is the determinant of estimate class, not the percentage. The specific deliverables, and their maturity, or status, are provided in Table 3. The other characteristics are secondary and are generally correlated with the maturity level of project definition deliverables, as discussed in the generic RP[1]. The characteristics are typical for the hydropower industry but may vary from application to application depending on location and output of power profile.

This matrix and guideline outlines an estimate classification system that is specific to the hydropower industry. Refer to the generic estimate classification RP[1] for a general matrix that is non-industry specific, or to other RPs for guidelines that will provide more detailed information for application in other industries. These will provide additional information, particularly the project definition deliverable maturity matrix which determines the class in those particular industries.

Table 1 illustrates typical variation of expected accuracy ranges that are associated with the hydropower industry. Depending on the technical maturity, complexity, project deliverables, contracting strategy (and other variables) and risks associated with each estimate, the accuracy range for any particular estimate is expected to fall into the ranges identified (although extreme risks can lead to wider ranges).

In addition to the degree of project definition, estimate accuracy is also driven by other systemic risks such as:

- Labor market conditions.
- Level of new technology in the project.
- Complexity of the project.
- Quality of reference cost estimating data.
- Quality of assumptions used in preparing the estimate.
- Experience and skill level of the estimator.

- Estimating techniques employed.
- Time and level of effort budgeted to prepare the estimate.
- Experience of the project execution team.

Systemic risks such as these are often the primary driver of accuracy; however, project-specific risks (e.g. risk events) also drive the accuracy range [5]. Project risks that are typical and often significant for the hydropower industry include the following:

- Project duration length (including studies and investigations) that is often measured in decades.
- Large areas where sub-surface geotechnical conditions are unknown due to restricted access (i.e. environmental regulatory restrictions, hazardous conditions).
- Difficulties in completion of transmission connection.
- Hydrology and hydraulic studies.
- Management or prevention of scouring and sediment transport due to construction.
- Safety accidents unique to in-water work.
- Mass material sources and utilization (e.g., concrete and aggregate).
- Excavated material disposal.
- Construction season (restrictions due to environmental regulation, weather).
- Limited supplies of quality hydropower equipment and delivery delays.
- Ambiguous environmental regulation with respect to the industry.
- Environmental mitigation measures (terrestrial, avian, fish).

Another way to look at the variability associated with estimate accuracy ranges is shown in Figure 1. Depending upon the technical complexity of the project, the availability of appropriate cost reference information, the degree of project definition, and the inclusion of appropriate contingency determination, a typical Class 5 estimate for a hydropower project may have an accuracy range as broad as -50% to +100%, or as narrow as -20% to +30%.

Figure 1 also illustrates that the estimating accuracy ranges overlap the estimate classes. There are cases where a Class 5 estimate for a particular project may be as accurate as a Class 3 estimate for a different project. For example, similar accuracy ranges may occur for the Class 5 estimate of one project that is based on a repeat project with good cost history and data and the Class 3 estimate for another project involving new technology. It is for this reason that Table 1 provides a variation in the expected accuracy range values. The accuracy range is determined through a detailed and thorough risk analysis of the specific project.

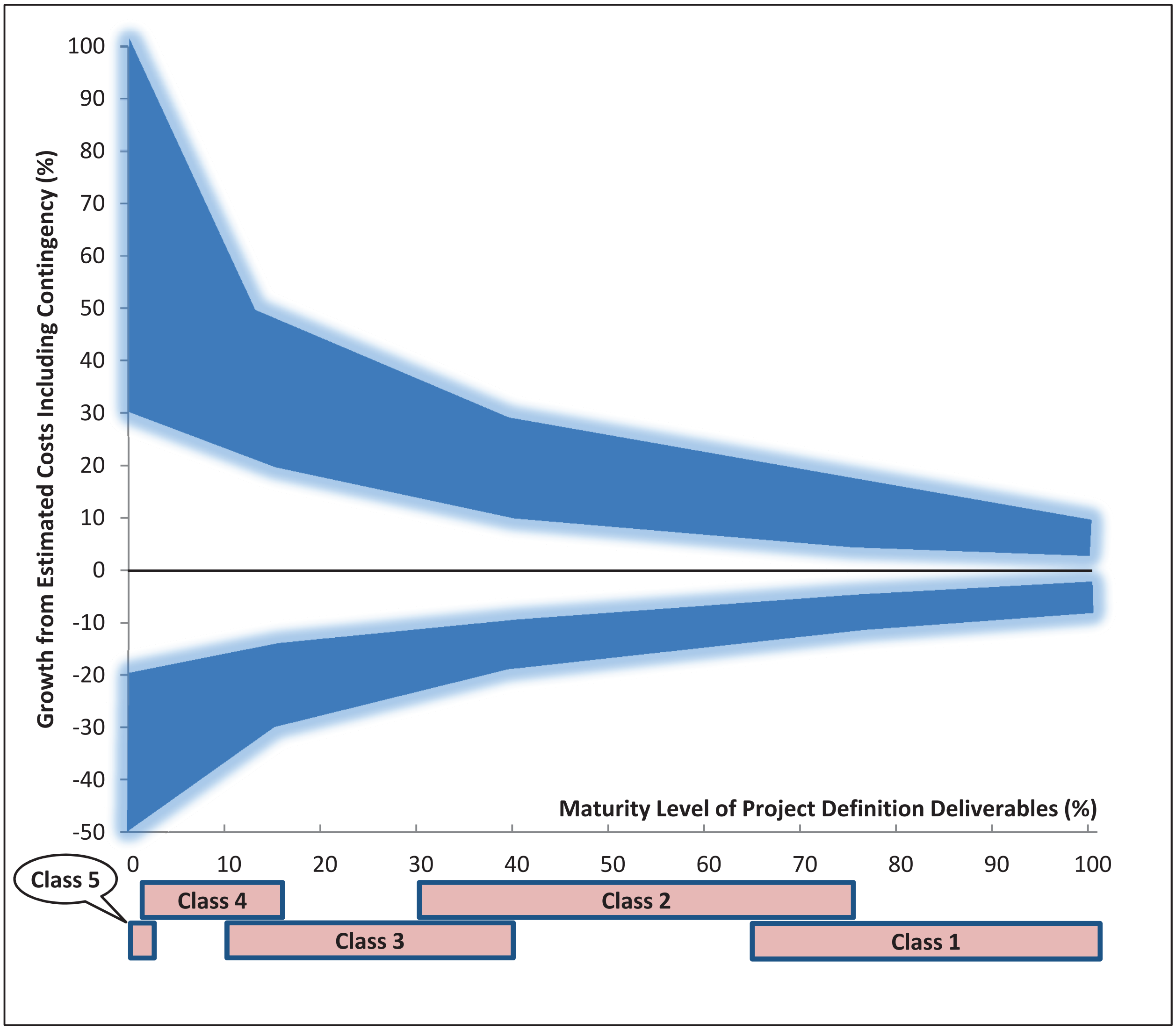

Figure 1 – Example of the Variability in Accuracy Ranges for a Hydropower Industry Estimate

DETERMINATION OF THE COST ESTIMATE CLASS

The cost estimator determines the cost estimate class based upon the maturity level of project definition which is based on the status of specific key planning and design deliverables. The percent design completion may be correlated with the status as a valuable indicator, but the percentage should not be used as the class determinate. While the determination of the status (and hence class) is somewhat subjective, having standards for the design input data, completeness and quality of the design deliverables, will serve to make the determination more objective.

CHARACTERISTICS OF THE ESTIMATE CLASSES

The following tables (2a through 2e) provide detailed descriptions of the five estimate classifications as applied in the hydropower industry. They are presented starting in the order of least-defined estimates and progressing to the most-defined estimates. These descriptions include brief discussions of each of the estimate characteristics that define an estimate class. For each table, the following information is provided:

- **Description:** A short description of the class of estimate, including a brief listing of the expected estimate inputs based on the maturity level of project definition deliverables. The "minimum" inputs reflect the range of industry experience, but would not generally be recommended.

- **Maturity Level of Project Definition Deliverables (Primary Characteristic):** Describes a particularly key deliverable and a typical target status in stage-gate decision processes, plus an indication of approximate percentage of full definition of project and technical deliverables. For the hydropower industry, and for that matter other related process/construction related industries, this correlates with the percentage of engineering and design complete.

- **End Usage (Secondary Characteristic):** A short discussion of the possible end usage of this class of estimate.

- **Estimating Methodology (Secondary Characteristic):** A listing of the possible estimating methods that may be employed to develop an estimate of this class.

- **Expected Accuracy Range (Secondary Characteristic):** This is the typical variation in low and high ranges after the application of contingency (determined at a 50% level of confidence that the costs will over-run or under-run). Typically, this represents about an 80% confidence interval that the actual cost will fall within the bounds of the low and high ranges. The estimate confidence interval or accuracy range is driven by the reliability of the scope information available at the time of the estimate in addition to the other variables and risk identified above.

- **Alternate Estimate Names, Terms, Expressions, Synonyms:** This section provides other commonly used names that an estimate of this class might be known by. These alternate names are not endorsed by this recommended practice. The user is cautioned that an alternative name may not always correlate and could mislead in selecting the appropriate class of estimate as identified in Tables 2a-2e.

CLASS 5 ESTIMATE	
Description: Class 5 estimates are generally prepared based on very limited information, and subsequently have wide accuracy ranges. As such, some companies and organizations have elected to determine that due to the inherent inaccuracies, such estimates cannot be classified in a conventional and systematic manner. Class 5 estimates, due to the requirements of end use, may be prepared within a very limited amount of time and with little effort expended—sometimes requiring less than a day to prepare. Often, little more than a proposed facility layout, location, and generation capacity based on a statement of objectives are known at the time of estimate preparation. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: General arrangement diagram/sketch that defines the project location and statement of objectives agreed by key stakeholders and project sponsor/initiator. 0% to 2% of full project definition. **End Usage:** Class 5 estimates are prepared for any number of strategic business planning purposes, such as but not limited to market studies, assessment of initial viability, evaluation of alternate schemes, project screening, project location selection studies, evaluation of resource needs and high level budgeting, long-range capital planning, etc.	**Estimating Methodology:** Class 5 estimates generally use stochastic estimating methods such as cost/capacity curves and factors, historical data and other parametric and modeling techniques. **Expected Accuracy Range:** Typical accuracy ranges for Class 5 estimates are -20% to -50% on the low side, and +30% to +100% on the high side, depending on the technological complexity of the project, appropriate reference information and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Factored, ballpark, blue sky, seat-of-pants, WAG, first cut, idea study, conceptual level estimate, order-of-magnitude estimate, guesstimate, rule-of-thumb, top down.

Table 2a – Class 5 Estimate

CLASS 4 ESTIMATE	
Description: Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, alternative concept evaluation, and definition phase (preliminary) budget approval. Typically, engineering is from 1% to 15% complete, and would comprise at a minimum the following: Feasibility design for several alternative layouts to include design criteria, generation capacity, feasibility level drawings, preliminary one-line diagrams, and comprehensive user requirements. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: Feasibility design report for feasible alternative schemes. 1% to 15% of full project definition. **End Usage:** Class 4 estimates are prepared for a number of purposes, such as but not limited to, detailed strategic planning, business case development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, selection of a feasible alternative and preliminary budget approval to proceed to next stage of the project (definition phase).	**Estimating Methodology:** Class 4 estimates generally use stochastic estimating methods such as cost/capacity graphs or curves and factors, historical data and other parametric and modeling techniques. **Expected Accuracy Range:** Typical accuracy ranges for Class 4 estimates are -15% to -30% on the low side, and +20% to +50% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Screening, top-down, feasibility level, definition phase authorization, factored, pre-design, pre-study.

Table 2b – Class 4 Estimate

CLASS 3 ESTIMATE	
Description: Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to 40% complete, and would comprise at a minimum the following: Preliminary general arrangement drawings, powerhouse, intake and spillway drawings and specifications, essentially complete geotechnical investigations and hydrotechnical studies, preliminary earthwork drawings for excavation defining unclassified and rock, rock support and foundation treatment and for embankment c/w definition for various zones, complete one-line diagrams, equipment performance specifications complete for turbines, generators, governors, and exciters, preliminary auxiliary mechanical and electrical systems, and preliminary piping and instrument/protection & control/telecom systems. Also, procurement strategy identifying long lead items of equipment. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: Preliminary design report complete with project description. 10% to 40% of full project definition. **End Usage:** Class 3 estimates are typically prepared to support full project funding requests, and become the first of the project implementation phase control estimates against which all actual costs and resources will be monitored for variations to the budget.	**Estimating Methodology:** Class 3 estimates generally involve more deterministic estimating methods than stochastic methods. They usually involve predominant use of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring and other stochastic methods may be used to estimate less-significant areas of the project. **Expected Accuracy Range:** Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Budget, scope, sanction, semi-detailed, authorization, preliminary control, preliminary design level estimate, target estimate, bottom-up.

Table 2c – Class 3 Estimate

CLASS 2 ESTIMATE	
Description: Class 2 estimates are generally prepared to form a detailed contractor control baseline (and update the owner control baseline) against which all project work is monitored in terms of cost and progress control. For contractors, this class of estimate is often used as the bid estimate to establish contract value. Typically, engineering is from 30% to 75% complete, and would comprise at a minimum the following: final geotechnical investigations, and hydrotechnical reports, professional engineer sealed drawings and specifications for general arrangements, earthwork excavation and embankments, powerhouse, intake and spillway (for all engineering disciplines), for major equipment (i.e. turbines generators, governors and exciters), auxiliary mechanical and electrical systems, one-line diagrams, and piping, instrument, protection and control and telecom systems, and permanent/temporary infrastructure. Vendor quotations, detailed project execution plans, procurement strategy identifying all major items of equipment, resourcing and work force plans, etc. would also be required. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: Tender specifications, reports, background information and drawings complete for tender purposes. 30% to 75% of full project definition. **End Usage:** Class 2 estimates are typically prepared as the detailed contractor control baseline (and update the owner control baseline) against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change management program.	**Estimating Methodology:** Class 2 estimates generally involve a high degree of deterministic estimating methods. Class 2 estimates are prepared in great detail, and often involve thousands of line items. For those areas of the project still undefined, an assumed level of detail takeoff (forced detail) may be developed using unit cost line items in the estimate instead of relying on factoring methods. **Expected Accuracy Range:** Typical accuracy ranges for Class 2 estimates are -5% to -15% on the low side, and +5% to +20% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Detailed control, forced detail, execution phase, master control, engineer's estimate, bid, tender, change order estimate, bottom-up.

Table 2d – Class 2 Estimate

CLASS 1 ESTIMATE	
Description: Class 1 estimates are generally prepared for discrete parts or sections of the total project rather than generating this level of detail for the entire project. The parts of the project estimated at this level of detail will typically be used by subcontractors for bids, or by owners for check estimates. The updated estimate is often referred to as the current control estimate and becomes the new baseline for cost/schedule control of the project. Class 1 estimates may be prepared for parts of the project to comprise a fair price estimate or bid check estimate to compare against a contractor's bid estimate, or to evaluate/dispute claims. Typically, overall engineering is from 65% to 100% complete (some parts or packages may be complete and others not), and would comprise virtually all engineering and design documentation of the project, and complete project execution and commissioning plans. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: All deliverables in the maturity matrix complete. 65% to 100% of full project definition. **End Usage:** Generally, owners and EPC contractors use Class 1 estimates to support their change management process. They may be used to evaluate bid checking, to support vendor/contractor negotiations, or for claim evaluations and dispute resolution. Construction contractors may prepare Class 1 estimates to support their bidding and to act as their final control baseline against which all actual costs and resources will now be monitored for variations to their bid. During construction, Class 1 estimates may be prepared to support change management.	**Estimating Methodology:** Class 1 estimates generally involve the highest degree of deterministic estimating methods, and require a great amount of effort. Class 1 estimates are prepared in great detail, and thus are usually performed on only the most important or critical areas of the project. All items in the estimate are usually unit cost line items based on actual design quantities. **Expected Accuracy Range:** Typical accuracy ranges for Class 1 estimates are -3% to -10% on the low side, and +3% to +15% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Full detail, release, fall-out, tender, firm price, bottoms-up, final, detailed control, forced detail, execution phase, master control, fair price, definitive, change order estimate.

Table 2e – Class 1 Estimate

ESTIMATE INPUT CHECKLIST AND MATURITY MATRIX

Table 3 maps the extent and maturity of estimate input information (deliverables) against the five estimate classification levels. This is a checklist of basic deliverables found in common practice in the hydropower industry. The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following letters.

- **None (N):** Development of the deliverable has not begun.
- **Started (S):** Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- **Preliminary (P):** Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- **Complete (C):** The deliverable has been reviewed, approved and issued for design as appropriate.

To produce an estimate of a certain class, without qualifications, all deliverables listed in Table 3 must be advanced to the level of completion associated with the estimate class.

	ESTIMATE CLASSIFICATION				
	CLASS 5	**CLASS 4**	**CLASS 3**	**CLASS 2**	**CLASS 1**
MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES	**0% to 2%**	**1% to 15%**	**10% to 40%**	**30% to 75%**	**65% to 100%**
General Project Data:					
Project Scope of Work Definition	S	S	P	P	C
Facility Output Profile & Nameplate Capacity	S	P	C	C	C
Site Infrastructure (Access, Construction Power, Camp etc.)	N	S	P/C	C	C
Principal Works (Location)	S	P	C	C	C
Hydraulic & Hydrology	S	P	C	C	C
Topography & Bathymetry	S	P	P/C	C	C
Geotechnical Investigation	N	S	P/C	C	C
Material Utilization (Borrow Sources)	S	P	P/C	C	C
Environmental Studies	S	P	C	C	C
Environmental Monitoring (During Construction & Operations)	N	N	N	S	P
Stakeholder Engagement	N	S/P	P	P/C	C
Regulatory Approval & Permitting	S	P	C	C	C
Integrated Project Plan	S	P	C	C	C
Project Schedule Baseline	S	P	P/C	C	C
Work Breakdown Structure (WBS)	S	P	P/C	C	C
Workforce Estimates	N	S	P	C	C
Project Code of Accounts (Control Accounts)	N	S	P	C	C
Equipment Procurement Strategy (Owner vs. Contractor)	N	S	C	C	C
Contracting and/or Outsourcing Strategy	N	S	C	C	C

January 25, 2013

	ESTIMATE CLASSIFICATION				
	CLASS 5	**CLASS 4**	**CLASS 3**	**CLASS 2**	**CLASS 1**
MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES	**0% to 2%**	**1% to 15%**	**10% to 40%**	**30% to 75%**	**65% to 100%**
Engineering Deliverables * (Specifications and/or Drawings)					
General Arrangement Design & Drawings	S	S/P	P / C	C	C
Project Parameters	S	P	C	C	C
PMF and Hydraulic Design	S	P	C	C	C
Dam Design & Drawings	N	S	P	P/C	C
Intake Design & Drawings	N	S	P	P/C	C
Penstock Design & Drawings	N	S	P	P/C	C
Power House Design & Drawings	N	S	P	P/C	C
Spillway Design & Drawings	N	S	P	P/C	C
De-Silting Basins	N	S	P	P/C	C
Power Tunnel/Canal	N	S	P	P/C	C
Gates and Cranes Design & Drawings	N	S	P	P/C	C
Turbine and Generator Design & Drawings	N	S	P	P/C	C
Electrical One-Line Drawings	N	N	S	P	C
Auxiliary Mechanical Design & Drawings	N	N	S	P	C
Auxiliary Electrical Design & Drawings	N	N	S	P	C
Protection & Controls System Design & Drawings	N	N	S	P	C
Telecommunication System Design & Drawings	N	N	S	P	C
Spare Parts Spec (Commissioning & Operation)	N	N	S	P	C
Mitigation Measures (Aquatic, Terrestrial, Avian, Clearing, Heritage etc.)	N	S	P	C	C

Table 3 – Estimate Input Checklist and Maturity Matrix

*Some of the above engineering deliverables may not be applicable to all projects.

REFERENCES

1. AACE International Recommended Practice No. 17R-97, *Cost Estimate Classification System*, AACE International, Morgantown, WV. (latest revision)
2. AACE International Recommended Practice No. 18R-97, *Cost Estimate Classification System*, AACE International, Morgantown, WV. (latest revision)
3. Hollmann, John K., PE CCE, Editor, *Total Cost Management Framework: An Integrated Approach to Portfolio, Program and Project Management*, AACE International, Morgantown, WV. (latest revision)
4. AACE International, Recommended Practice 10S-90, *Cost Engineering Terminology*, AACE International, Morgantown, WV. (latest revision)

5. AACE International, Recommended Practice 42R-08, *Risk Analysis and Contingency Determination Using Parametric Estimating*, AACE International, Morgantown, WV. (latest revision)

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ATTACHMENT 11

PG&E Response to Cal Advocates Data Request 003, Question 14

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_003-Q014		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_003-Q014		
Request Date:	March 29, 2024	Requester DR No.:	PGE-A2312014-003
Date Sent:	April 22, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jenn Scott	Requester:	Michael George/ Paul Worhach

QUESTION 014

PG&E's response to Public Advocates Office Data Request-PGE-A2312014-001, Question 13.a states

> "Though the Helms Uprate project is a high complexity project, it was decided that using 50% contingency, in line with a Class 4 high complexity project, was more appropriate than using 100% contingency."

Please justify the decision to use a contingency in line with a Class 4 high complexity project, as opposed to a contingency in line with any other class of cost estimate with any degree of complexity.

ANSWER 014

The Class 5 AACE Estimate Uncertainty recommended percentage ranges from 20% for Low Complexity to 100% for High Complexity. The Class 4 AACE Estimate Uncertainty recommended percentage ranges from 15% for Low Complexity to 50% for High Complexity. The Helms Uprate project used a single calculation for total contingency which represents the total AACE Estimate Uncertainty plus total Value of Risk. The team used professional judgement to determine a total contingency of 50% was adequate for the Uprate.

A 50% total contingency was determined to be more appropriate for the Helms Uprate Project than a 100% total contingency when the team considered that similarly complex work had been performed at Helms in the past. It is estimated that there are less unidentified risks than a typical high complexity Class 5 project because of the similar complex outage work performed over the past 20 years at Helms.

A 50% total contingency is within the recommended percentage range for Class 5 AACE Estimate Uncertainty and on the higher end of the recommended percentage range for Class 4 AACE Estimate Uncertainty. The team's professional judgement caused them to feel that 100% AACE Estimate Uncertainty on top of the Value of Risks was too much contingency to justify for the level of scope development and cost estimate references, so they lowered the total contingency to a value that was reasonable based on the team's experience and judgment.

ATTACHMENT 12

PG&E Response to Cal Advocates Data Request 003, Question 10.c

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_003-Q010		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_003-Q010		
Request Date:	March 29, 2024	Requester DR No.:	PGE-A2312014-003
Date Sent:	April 22, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jenn Scott	Requester:	Michael George/ Paul Worhach

QUESTION 010

Referring to Table 3 of PG&E's Project Cost Management Standard (Utility Standard: PM-1015S), please define the following terms, explain how their values are determined, and explain how they relate to each other:

a. Weighted/ Expected value of AACE Estimate Uncertainty

b. Total Value of AACE Estimate Uncertainty

c. Weighted/ Expected Value of Risk

ANSWER 010

a. Weighted/Expected value of AACE Estimate Uncertainty is a percent of the total AACE Estimate Uncertainty that is used in the calculation of the Expected Cost Estimate. The recommended percentages can be found in Table 3 on page 17 of PG&E's Utility Standard: PM-1015S. The Expected Cost Estimate is the Base Estimate + Weighted/Expected value of AACE Estimate Uncertainty + Weighted/Expected Value of Risk.
b. Total Value of AACE Estimate Uncertainty is a percent of the total estimated cost that is added to the Base Estimate as part of the contingency to determine the High Case Estimate. The recommended percentages can be found in Table 3 on page 17 of PG&E's Utility Standard: PM-1015S. AACE Estimate Uncertainty is selected percentage times (Base Case + Value of Risk). The High Case Cost Estimate is the Base Estimate + Total Value of AACE Estimate Uncertainty + Total Value of Risk.
c. Weighted/Expected Value of Risk is the total sum of expected risk value times the probability of the risk occurring for each identified risk. The Expected Cost Estimate is the Base Estimate + Weighted/Expected value of AACE Estimate Uncertainty + Weighted/Expected Value of Risk.

ATTACHMENT 13

PG&E Response to Cal Advocates Data Request 001, Question 29

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_001-Q029		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_001-Q029		
Request Date:	March 6, 2024	Requester DR No.:	PGE-A2312014-001
Date Sent:	March 20, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jennifer Scott	Requester:	Michael George/ Paul Worhach

SUBJECT: DATA REQUEST NO. PGE-A2312014-001

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* (Application).

QUESTION 029

The Joint Applicants describe the use of two “bookend” scenarios used to estimate the NMV of the project.[1] Describe in greater detail how these two scenarios were selected.

ANSWER 029

PG&E calculated the Helms’ Uprate Net Market Value (NMV) for two capacity scenarios. The scenarios are meant to provide reasonable “book ends” for the potential outcome of the project based on the initial design studies. The higher incremental capacity scenario, Scenario 1, is based on 156 MW and 78 MW of increased capacity for generation and pumping at the interconnection point, respectively. The lower incremental capacity scenario, Scenario 2, is the based on 129 MW and 0 MW of increased capacity for generation and pumping at the interconnection point, respectively.

The generation increase was based on a Hitachi study that that indicated a range of nameplate generation increase of 51 - 59 MW per unit, or 153 - 177 MW for the facility (or approximately 150-180 MW). The capacity increase at the point of interconnection is less than the increase in nameplate capacity due to transformer and transmission line losses between the Helms’ generators and the point of interconnection at Gregg Substation. Accounting for these losses reduces the incremental generation capacity at the point of interconnection to 129 -156 MW.

The estimated increase in the pumping capacity was informed by input from consultants. The increase in the pumping capacity increase per unit was estimated to be between zero and 39 MW. The high estimate assumes a similar 13% increase in pumping capacity as seen with generation capacity at the interconnection (156/1212). A thirteen percent increase in the current pumping capacity of 300 MW is 39 MW.

---

1 Application, Prepared Testimony at 3-18.

Since the NMV analysis limits pumping from two units (please see answer to question 22 for more details), the incremental pumping capacity at the point of interconnection is 0 - 78 MW.

ATTACHMENT 14

PG&E Response to CPUC Data Request 002, Question 5

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CPUC_002-Q005
PG&E File Name:	HelmsUprateProject_DR_CPUC_002-Q005
Request Date:	September 20, 2024
Requester DR No.:	002
Requesting Party:	California Public Utilities Commission
Requester:	ALJ Justin Regnier
Date Sent:	October 23, 2024
PG&E Witness(es):	Jenn Scott

SUBJECT: INFORMATION IN PG&E'S POSSESSION THAT MAY REQUIRE COMPILATION

Current Rated and Maximum Power

Many of the documents supporting the Application address maximum power attainable by the Uprate project. The plant is operated, however, at its rated power. On this point, the below supplemental information is required:

QUESTION 005

Clarify what the rated power will be for each unit under the uprate proposal. If this rating is subject to the rock chamber[1] modifications or other unstudied measures, PG&E shall specify the dependencies and give a range of anticipated rated power for each unit; and

ANSWER 005

The Helms Uprate project proposes to increase the generation output of the three existing units by 150 – 180 megawatts (MW). The existing units are rated[2] 404 MW each based on the generator nameplate rating of 448.5 megavolt-ampere (MVA)[3]. 404 MW is calculated by multiplying the generator MVA rating by 0.9 power factor (448.5 MVA * 0.9 power factor = 403.65 MW = 404 MW (rounded)).

---

1 PG&E Prepared Testimony, p. 2-2; "The extent of modifications to the rock chamber will be an important factor as to how much increase in capacity can be achieved."

2 There are many ways to calculate rated power in different contexts and for different regulators (for example FERC, NERC, and CAISO). The calculation details are provided for transparency and achievement of rated output is dependent on head conditions.

3 The existing turbines are rated (at rated head) 480,000 horsepower (HP) or 357.9 MW (480,000 HP * 0.0007457 MW/HP = 357.9 MW). The existing units operate at a maximum output of 407 MW for unit 1, 407 MW for unit 2, and 404 MW for unit 3.

The Uprated units are anticipated to be rated between 454 MW to 464 MW each, pending final turbine design and model results.

An Uprated unit rated at 454 MW would correspond to a generator nameplate rating of 504.4 MVA and a turbine maximum output of 463.3 MW (454 MW generator rating divided by 98% generator efficiency).

An Uprated unit rated at 464 MW would correspond to a generator nameplate rating of 515.5 MVA and a turbine maximum output of 473.5 MW (464 MW generator rating divided by 98% generator efficiency).

The maximum megawatt power output that the Uprated units will be able to generate is limited by the capability of the new turbine design. Turbine design includes design of the water wheel as well as design modifications to the surrounding turbine equipment, such as the discharge ring and portions of the draft tube. The Uprated unit will have a rating based on the maximum turbine output per model testing results times 98% generator efficiency.

ATTACHMENT 15

PG&E Response to Cal Advocates Data Request 013, Question 11.c, 11.e

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_013-Q011
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_013-Q011
Request Date:	October 22, 2024
Requester DR No.:	PGE-A2312014-013
Requesting Party:	Public Advocates Office
Requester:	Patrick Huber/Paul Worhach
Date Sent:	November 4, 2024
PG&E Witness(es):	Jenn Scott

The data request pertains to Application (A.) 23-12-014, *First Amended Application of Pacific Gas and Electric Company (U 39 E) to Recover Helms Uprate Costs (Application)*.

QUESTION 011

How did PG&E calculate the expected range for incremental capacities: 150-180 MW?

a. Was 150 MW derived as follows based on the Hitachi Turbine Study using the following calculations? Please confirm or correct.

   i. Turbine output at Hmax (Plan A) = 455 MW;[1]

   ii. Current nameplate capacity = 404 MW;

   iii. 455 – 404 = 51;

   iv. 51 * 3 = 153; and

   v. 153 is rounded to 150.

b. Was 180 MW derived as follows based on the Hitachi Turbine Study using the following calculations? Please confirm or correct.

   i. Turbine output at Hmax (Plan B) = 463 MW;[2]

   ii. Current nameplate capacity = 404 MW;

   iii. 463 – 404 = 59;

   iv. 59 * 3 = 177; and

   v. 177 is rounded to 180.

c. Was 180 MW derived as follows based on the Stantec Analysis of Alternatives, Alternative 3 using the following calculations? Please confirm or correct.

   i. Upper limit of turbine power output = 460 MW;

---

1 Prepared Testimony, Chapter 2, Attachment A, *Hitachi Turbine Study*, p. 2-AtchA-4.

2 Prepared Testimony, Chapter 2, Attachment A, *Hitachi Turbine Study*, p. 2-AtchA-4.

ii. 460 MW changed to 464 MW because 460 MW is too conservative;

iii. 464 – 404 = 60; and

iv. 60 * 3 = 180.

d. Does the incremental capacity refer to turbine output, generator output, or another value? Please specify.

e. At what net head are current, uprated, and incremental capacities evaluated? Please provide answer(s) in feet.

f. Are current, uprated, and incremental capacities calculated based on single-unit operation (multiplied by 3 to get plant total) or on three-unit operation?

ANSWER 011

a. The 150 MW incremental capacity was derived based on the Hitachi Turbine Study results of estimated maximum turbine output of 463 MW, which has a corresponding estimated maximum generator output of 453.74 MW (based on estimated assumed generator efficiency of 98%) and rounded to 454 MW. The maximum turbine output was used to reflect the lower end of the Uprate range because PG&E believes the Hitachi estimates for uprated turbine performance are conservative[3]. The 150 MW incremental capacity is then calculated as 454 * 3 = 1362 MW – 1212 MW = 150 MW. A turbine model test is required to confirm actual incremental capacity capability.

b. See response in c. below.

c. The 180 MW incremental capacity was derived based on multiple inputs. First, the Unit 2 generator was evaluated and determined to be capable of operating at 515.5 mega volt-ampere (MVA) or 464 MW and can receive an updated nameplate when operational testing is possible. Second, based on the Black and Veatch Feasibility Study and the Stantec Analysis of Alternatives, there is a general consensus that 460 MW individual generator output or 1380 MW plant generator output is achievable. PG&E believes the Hitachi estimates for uprated turbine performance, which is the limiting factor, to be conservative and therefore increased the maximum generator output by less than 1% from 460 MW to 464 MW to match the Unit 2 generator capability and from 1380 MW to 1392 MW for the total plant generator capability. The 180 MW incremental capacity is then calculated as 1392 MW – 1212 MW = 180 MW. A turbine model test is required to confirm actual incremental capacity capability.

d. The incremental capacity refers to the generator output. Current generator nameplate rating is 404 MW and the Uprated generator nameplate rating is estimated to range from 454 MW to 464 MW.

e. The existing Helms Units are capable of operating at 404 MW over a range of gross heads (1744 feet to 1600 feet or less; operational data was spot checked to understand possible range). Net Head is not measured and is a theoretical

[3] Please see PG&E's response to CalAdvocates_005-Q004 for more details.

value that varies upon flow; therefore, data has been provided for gross head. The Uprated MW capacity targets are based on maximum net head, in which Hitachi estimates maximum net head as 1744 feet and Stantec estimates maximum net head as 1719 feet. The incremental capacities represent the Uprated capacity targets minus the existing capacities and hence they are just a different way to represent the Uprated capacity targets.

f. Current and Uprated capacities are calculated based on single-unit operation (multiplied by 3 to get plant total) and on three-unit operation. The current units are capable of maximum operation of 407 MW, 407 MW, and 404 MW and they are capable of operating simultaneously at 1218 MW. The Uprated units are estimated to be capable of maximum operation of 454-464 MW each and they are estimated to be capable of operating simultaneously at 1362-1392 MW. The incremental capacities represent the Uprated capacity targets minus the existing capacities and hence they are just a different way to represent the Uprated capacity targets.

ATTACHMENT 16

PG&E Response Cal Advocates Data Request 013, Question 2

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_013-Q002
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_013-Q002
Request Date:	October 22, 2024
Requester DR No.:	PGE-A2312014-013
Requesting Party:	Public Advocates Office
Requester:	Patrick Huber/Paul Worhach
Date Sent:	November 4, 2024
PG&E Witness(es):	Jenn Scott

The data request pertains to Application (A.) 23-12-014, *First Amended Application of Pacific Gas and Electric Company (U 39 E) to Recover Helms Uprate Costs (Application)*.

QUESTION 002

What is the maximum total power output that the three Helms units are capable of generating simultaneously (sum of generator outputs, in MW)?

ANSWER 002

The maximum total power output that the three Helms units are capable of generating simultaneously is 1218 MW.

ATTACHMENT 17

PG&E Response to Cal Advocates Data Request 013, Question 6

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_013-Q006
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_013-Q006
Request Date:	October 22, 2024
Requester DR No.:	PGE-A2312014-013
Requesting Party:	Public Advocates Office
Requester:	Patrick Huber/Paul Worhach
Date Sent:	November 4, 2024
PG&E Witness(es):	Jenn Scott

The data request pertains to Application (A.) 23-12-014, *First Amended Application of Pacific Gas and Electric Company (U 39 E) to Recover Helms Uprate Costs (Application)*.

QUESTION 006

What is the current total maximum turbine output capability for all three units (in three unit operation)?

ANSWER 006

The current maximum turbine output capability for all three units is not measured directly or separately from the maximum generator output. The theoretical maximum turbine output capability could be estimated based on an estimated assumed generator efficiency. If the estimated assumed generator efficiency was 0.98 and the maximum generator output for all three units was 1,218 megawatts (MW), then the theoretical maximum turbine output for all three units would be 1,242.86 MW or 1,666,702.71 horsepower.

ATTACHMENT 18

PG&E Response to Cal Advocates Data Request 005, Question 6

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_005-Q006		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_005-Q006		
Request Date:	April 19, 2024	Requester DR No.:	PGE-A2312014-005
Date Sent:	May 3, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jenn Scott	Requester:	Michael George/ Paul Worhach

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* (Application).

QUESTION 006

The Stantec Report states,

> "Plan A would require relatively little intervention to the existing unit and civil works, with only the upper portion (the first approximately 1.5 m) of the upper draft tube and discharge ring requiring modifications… Plan B modifications would involve the enlarged runner throat as well as substantial draft tube modifications which would involve heavy civil work and replacement of the entire draft tube."[1]

a. Does the significant difference in the magnitude of modifications required for Plan A vs Plan B impact the expected cost of the Helms Uprate? Please provide cost estimates for Plan A and Plan B.

b. Does the significant difference in the magnitude of modifications required for Plan A vs Plan B impact the expected Net Market Value of the Helms Uprate? Please provide Net Market Value estimates for Plan A and Plan B.

ANSWER 006

a. PG&E did not estimate the difference in cost between Plan A and Plan B. The exact scope of work for the draft tube area will not be known until the turbine design is selected. Accordingly, PG&E included an AACE Class 5 preliminary estimate for draft tube modifications, which were $2M per unit.

b. In the Net Market Value Analysis, PG&E provided a range for possible turbine megawatt (MW) performance to account for the potential that the maximum MW output design scenario results in consequences that may not make it the best overall turbine design. Such consequences might include very expensive / extensive draft tube modifications could trigger a decision to select a lower MW output design scenario. Other consequences that the PG&E team is trying to

1 Stantec Report at 11.

balance in the overall turbine design include maintaining the lower operating range and maximizing the efficiency.

For these reasons, the Net Market Value analysis has taken into consideration the not yet known variables in the turbine design.

ATTACHMENT 19

PG&E Response to Cal Advocates Data Request 005, Question 4

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_005-Q004		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_005-Q004		
Request Date:	April 19, 2024	Requester DR No.:	PGE-A2312014-005
Date Sent:	May 3, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jenn Scott	Requester:	Michael George/ Paul Worhach

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* (Application).

QUESTION 004

PG&E's testimony states,

> "The objective of the Uprate is to increase the generation capacity of Helms Pumped Storage Hydroelectric Power Plant (Helms) by 150--180 megawatts (MW), increasing the nameplate total capacity from 1,212 MW up to 1,392 MW."[1]

The uprate value of 1,392 MW corresponds to 464 MW per unit, or 4 MW greater than the upper limit of 460 MW per unit recommended in the Stantec Report, provided in response to Public Advocates Data Request-A2312014-001, Question 17.[2]

Additionally, Attachment A to PG&E's Testimony (Hitachi Turbine Study) appears to convert turbine power output to generator power output by multiplying by a factor of 0.98, such that a turbine power output of 463 MW is roughly converted to a generator power output of 454 MW.

a. Please justify PG&E's plan to increase the generating capacity of the Helms units beyond the range recommended in the Stantec Report, if that is the case.

b. Please clarify whether each of the capacity values cited above (150 MW,180 MW, 460 MW, 464 MW and 1392 MW) refers to turbine power output or generator power output.

ANSWER 004

a. Stantec's Report based their recommendation of 460 MW per unit on the results of the Hitachi Study and Model. PG&E believes that Hitachi's model result of 463 MW (Turbine) may be lower than what could be achieved with modern design since their model is extrapolated from the analytical model of the existing turbine

1 PG&E Testimony at 2-1.

2 Stantec Report at 20.

that underestimates the actual output of existing 404 MW generator unit both at high and normal net head.

Stantec validates this perspective on Page 19 of the Engineering Assessment (HelmsUprateProject_DR_CalAdvocates_001-Q017Atch01): "...we consider the Hitachi Plan A/B uprates to be representative of a careful, conservative approach to the maximum uprate that would be possible with no or minimal sacrifice to the lower operating range." Stantec further indicates that higher turbine capacity could be possible by adjusting the maximum efficiency point or lower operating range. Ultimately the uprated turbine performance will be determined and validated during physical model testing.

b. Each of the capacity values listed refers to generator power output.

ATTACHMENT 20

PG&E Response to Cal Advocates Data Request 005, Question 10.d

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_005-Q010		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_005-Q010		
Request Date:	April 19, 2024	Requester DR No.:	PGE-A2312014-005
Date Sent:	May 3, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jenn Scott	Requester:	Michael George/ Paul Worhach

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* (Application).

QUESTION 010

The Stantec report states:

> "Oftentimes, what is more significant to Owners is the maximum output at minimum net head, or turbine 'firm' output under all operating conditions."[1]

a. Does PG&E consider maximum output at minimum head more significant than maximum output at maximum head or normal head, as suggested by the Stantec Report?

b. How does PG&E consider maximum output at minimum net head when estimating the uprate capacity of the Helms Uprate project and the calculation of net market values?

c. How does PG&E use low, normal, and high net head forecasts to estimate the potential uprate capacity of the Helms facility?

d. Table 3-3 of the Stantec Report[2] indicates that the potential generating capacity for uprate Plans A and B at normal head is between 1,275 MW and 1,299 MW, while the potential generating capacity for uprate Plans A and B at minimum head is between and 1,020 MW and 1,035 MW. Explain how these values correspond to PG&E's projected Helms Uprate capacity of 1,362 MW to 1,392 MW.

ANSWER 010

a. Many pumped storage facilities have a much smaller reservoir storage capacity and often reach minimum head each generation cycle. Helms has much higher storage capacity than is typical for a pumped storage facility and rarely reaches

1 Stantec Report at 13.
2 Stantec Report at 13.

the minimum head. Therefore, PG&E is more concerned with output at maximum or normal head values.

b. The net market value analysis did not adjust for net head. Please see response to Question 9a, in which PG&E explains that Courtright and Wishon reservoirs are operated such that net head remains above 1,600 feet most of the year, enabling each Helms unit to achieve 404 MW (nameplate capacity) most of the year. Due to the large storage capacity of Courtright and Wishon, it is anticipated that similar operational protocol will be implemented for the Helms Uprated units, enabling each Helms Uprated unit to achieve between 454 and 464 MW most of the year.

c. PG&E used the high net head capacity estimates for Plan A and Plan B from the Hitachi Study as an approximation for the possible capacity increase of an uprated unit at maximum or normal net head. Please see response 4.a., in which PG&E explains that it believes the Hitachi study is underestimating the potential uprated amounts due to their existing model underestimating the current capacity performance of the existing Helms units.

d. Table 3-3 from the Stantec Report is an extrapolation of the Hitachi Study. Please see response 4.a. in which PG&E explains that it believes the Hitachi study is underestimating the potential uprated amounts due to their existing model underestimating the current capacity performance of the existing Helms units. Please see response 10.c. that explains PG&E used the high net head capacity estimates from the Hitachi Study as an approximation of the possible capacity increase of an uprated unit at maximum or normal net head. The actual values at high, normal, and minimum head will be determined once a turbine design is selected and physical model testing is performed.

ATTACHMENT 21

PG&E Response to Cal Advocates Data Request 001, Question 12, Attachment 1, Question 5

Questions Associated with Helms Uprate Project

1. Page 1-1 (Chapter 1) – How is the Net Cost of $27 million associated with the uprate determined? Is the ITC applied to the total capital expenditures of $462 million or to the Uprate incremental cost of $162 million. Table 2-3 in Chapter 2 identifies the 30% tax credit as providing $135 million in tax benefits. What is the rationale for that level of tax credit benefits. Please explain the basis and analysis supporting this application and associated results.

The total cost estimate is $462M. The 30% ITC was calculated on $450M which is $462M - $12M (12M is the estimated cost for interconnection) because interconnection related costs don't qualify for the ITC. 30% ITC was used based on current understanding of Inflation Reduction Act which describes the ITC to be a base of 6% or 30% if you can meet prevailing wage and apprenticeship requirements, which we plan on meeting.

The $27M is an illustrative value to show that when you compare the alternative to implementing the Uprate (which includes the tax credit) to implementing the Lifecycle work (work we would do if the Uprate is not approved), the Net Incremental Capacity Cost is $27M. Uprate $462M – Lifecycle $300M – ITC $135M = $27M. The $27M is illustrative, because the actual calculation of how the ITC is credited to customers is shown in the RRQ calculation and it is amortized. It's important to note, that Lifecycle Replacement work, without an uprate, would not qualify for the ITC. There is more detail about that in Chapter 4.

2. If the assessment above for determining the tax credits is based on total expenditures for the Lifecycle Replacement Work and the Uprate, how can the Lifecycle Replacement Work generate tax benefits? Why aren't the tax benefits based only on the Net Cost associated with the Uprate of $162 million.

The Lifecycle Replacement Work is a separate alternative project scope that would be implemented if the Uprate scope of work is not implemented. The estimate for the Lifecycle work is theoretical and will not ever become actual costs if the Uprate scope is implemented. It will not be possible to distinguish lifecycle costs from Uprate costs in the Uprate implementation, the uprate scope is a different scope of work than the lifecycle scope. Therefore, we believe the total cost of the Uprate will qualify for the tax credits because the total scope is needed to achieve the increased energy storage capacity.

3. As described in the cost effectiveness testimony, in the Revenue Requirements model, what are the uncollectible factor (0.33853%) and the franchise fee factor (o.78361%) derived from and used for?

Uncollectible and franchise fees factors, internally known as Revenue Fees and Uncollectibles (RF&U) factors, are values applied to certain revenue requirement outputs to estimate the noted annual accounting impacts (e.g. uncollectible revenues from customers). The values are adopted in major rate cases (e.g. GRC).

4. Exhibit YY in the Cost Effectiveness Testimony lists the same total RA value for both scenarios while other benefit streams differ. Is that reasonable? How can total RA value be the same if the capacity values are different?

The RA value in that table is the same across scenario as it is levelized. This is because the numerator and denominator change by the same percentage, so the ratio remains the same. In other words, the RA value per MW stays the same, as one would expect.

The table above it, with the values in PV $, shows the higher value when more MW are installed.

This phenomenon does not occur for energy and A/S as the pumping capability is not the same between the two scenarios, which affects the dispatch.

5. We are a bit confused regarding the two scenarios described in the Cost Effectiveness Testimony. If Scenario 2 has a lower total incremental capacity (156 MW vs 129 MW), why would the revenue requirements be the same at -$90.5 million and incremental cost be the same? Can you explain the differences besides the capacity in these two scenarios and why PG&E would pursue one over the other?

   We, of course, are pursing the higher capacity scenario, but the total MW capacity increase will not be verified until we perform turbine model testing in 2024/2025. The 2 scenarios were provided to be conservative in the benefit analysis and to align with our inability to guarantee a certain MW increase at this stage of the project. The cost is the same for both scenarios because we are assuming the same scope of work is required; the difference is in the outcome we are able to achieve, which is based on final design that is not yet completed.

6. Consolidated Results Workbook
   a. What are the three scenarios in the RRQ tab? How do they differ with regard to the assumptions made
   b. The cost steam declines significantly after 2032. What explains this drop?
   c. For the RA value calculations, what is the incremental MWs? Is it 129 MW? What RA values are applied to calculate the total RA benefits?

   Answer: The incremental MW is either 129 or 156 in cell E7, depending on the scenario selection made in cell E5 and E6 (on the "Summary"). The monthly RA value is calculated as the following:

   Take for example the RA value for 1/1/2031 at cell G45 = $231,137

G45 =IF($C45>=OnlineDate,Availability*IncMW*1000*XLOOKUP($C45,RA_ELCC!$B:$B,RA_ELCC!$E:$E)*(XLOOKUP($C45,RA_Curve!$B:$B,RA_Curve!$C:$C)+XLOOKUP($C45,RA_Curve!$B:$B,RA_Curve!$D:$D)+XLOOKUP($C45,RA_Curve!$B:$B,RA_Curve!$F:$F)),0)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
25		2029	5/1/2029	73%	0	0	0	-42,417	-42,417		2033	1,771,847	971,583	8,115,592	-9,106,854	1,752,1
26		2029	6/1/2029	72%	0	0	0	-42,417	-42,417		2034	2,209,194	773,962	8,207,901	-8,626,295	2,564,7
27		2029	7/1/2029	72%	0	0	0	-42,417	-42,417		2035	2,291,561	666,105	8,300,655	-7,870,919	3,387,4
28		2029	8/1/2029	71%	0	0	0	-42,417	-42,417		2036	2,229,138	722,820	8,393,837	-7,737,826	3,607,9
29		2029	9/1/2029	71%	0	0	0	-42,417	-42,417		2037	2,428,875	720,135	8,487,426	-7,597,672	4,038,7
30		2029	10/1/2029	71%	0	0	0	-42,417	-42,417		2038	2,359,295	659,558	8,581,400	-7,447,188	4,153,0
31		2029	11/1/2029	70%	0	0	0	-42,417	-42,417		2039	2,673,530	486,025	8,675,739	-7,298,897	4,536,3
32		2029	12/1/2029	70%	0	0	0	-42,417	-42,417		2040	2,835,275	610,251	8,770,418	-7,860,631	4,355,3
33		2030	1/1/2030	69%	0	0	0	-1,267,749	-1,267,749		2041	2,429,320	274,836	8,865,415	-7,706,778	3,862,7
34		2030	2/1/2030	69%	0	0	0	-1,267,749	-1,267,749		2042	2,368,932	360,688	8,960,703	-7,552,925	4,137,3
35		2030	3/1/2030	69%	0	0	0	-1,267,749	-1,267,749		2043	2,361,076	407,685	9,056,256	-7,399,072	4,425,9
36		2030	4/1/2030	68%	0	0	0	-1,267,749	-1,267,749		2044	2,381,698	295,866	9,152,048	-7,245,220	4,584,3
37		2030	5/1/2030	68%	0	0	0	-1,267,749	-1,267,749		2045	2,433,544	292,351	9,248,048	-7,091,367	4,882,5
38		2030	6/1/2030	68%	0	0	0	-1,267,749	-1,267,749		2046	2,380,593	431,295	9,433,009	-6,937,514	5,307,3
39		2030	7/1/2030	67%	0	0	0	-1,267,749	-1,267,749		2047	2,365,705	353,845	9,621,669	-6,783,661	5,557,5
40		2030	8/1/2030	67%	0	0	0	-1,267,749	-1,267,749		2048	2,381,526	476,144	9,814,103	-6,629,808	6,041,9
41		2030	9/1/2030	67%	0	0	0	-1,267,749	-1,267,749		2049	2,439,424	318,702	10,010,385	-6,482,290	6,286,2
42		2030	10/1/2030	66%	0	0	0	-1,267,749	-1,267,749		2050	2,316,897	349,755	10,210,592	-6,354,781	6,522,4
43		2030	11/1/2030	66%	0	0	0	-1,267,749	-1,267,749		2051	2,430,090	326,182	10,414,804	-6,255,042	6,916,0
44		2030	12/1/2030	65%	0	0	0	-1,267,749	-1,267,749		2052	2,353,811	345,940	10,623,100	-6,176,001	7,146,8
45		2031	1/1/2031	65%	104,454	71,743	231,137	-1,266,846	-859,513		2053	2,301,866	516,230	10,835,562	-6,103,406	7,550,2
46		2031	2/1/2031	65%	104,454	71,743	221,628	-1,266,846	-869,022		2054	2,278,061	345,448	11,052,274	-6,030,660	7,645,1
47		2031	3/1/2031	64%	104,454	71,743	276,812	-1,266,846	-813,837		2055	2,128,256	459,281	11,273,319	-5,957,919	7,902,9
48		2031	4/1/2031	64%	104,454	71,743	289,520	-1,266,846	-801,130		2056	2,241,618	530,337	11,498,785	-5,885,177	8,385,5
49		2031	5/1/2031	64%	104,454	71,743	376,446	-1,266,846	-714,204		2057	2,519,332	362,877	11,728,761	-5,812,435	8,798,5
50		2031	6/1/2031	63%	104,454	71,743	1,091,908	-1,266,846	1,259		2058	2,460,184	413,080	11,963,336	-5,739,693	9,096,9
51		2031	7/1/2031	63%	104,454	71,743	1,121,235	-1,266,846	30,586		2059	2,314,903	446,834	12,202,603	-5,666,951	9,297,3
52		2031	8/1/2031	63%	104,454	71,743	1,289,176	-1,266,846	198,526		2060	2,361,201	455,771	12,446,655	-5,594,210	9,669,4
53		2031	9/1/2031	62%	104,454	71,743	1,757,962	-1,266,846	667,313		2061	2,408,425	464,886	12,695,588	-5,521,468	10,047,4
54		2031	10/1/2031	62%	104,454	71,743	723,906	-1,266,846	-366,743		2062	2,456,593	474,184	12,949,500	-5,448,726	10,431,5
55		2031	11/1/2031	62%	104,454	71,743	330,256	-1,266,846	-760,394		2063	2,505,725	483,668	13,208,490	-5,375,984	10,821,8
56		2031	12/1/2031	61%	104,454	71,743	325,640	-1,266,846	-765,009		2064	2,555,840	493,341	13,472,660	-5,303,243	11,218,5
57		2032	1/1/2032	61%	129,564	80,559	231,910	-1,797,438	-1,355,406		2065	2,606,956	503,208	13,742,113	-5,230,501	11,621,7

Summary | PastedResult_wTransAdder | PastedResult | EnergyAS | RRQ | RA_ELCC | RA_Curve ...

This is the set up where incremental MW is 129mw:

	A	B	C	D	E	F	G	H
1		CONFIDENTIAL - ATTORNEY CLIENT WORK PRODUCT						
2								
3				***Input Parameters:***				
4							PV Date	6/1/2024
5				Gen Case	Low		Disc Rate	6.70%
6				Pump Case	Same		Availability	77%
7				MWs	129		BidID	2564

The calculation is as following:

(Availability Percentage 77% at cell H6) * (Incremental MW 129MW in cell E7) * (1000 kw/MW) * (ELCC 96.2% in cell E104 in "RA_ELCC" tab for Pump Storage Hydro) * (System RA + Flex RA + Local Premium for Fresno Location $2.15903095050683+$0.101104798180024+$0.15873878885815/kw-mon in cell C139, D139, E139)
= 77% * 129mw * 1000 * 96.2% * ($2.15903095050683+$0.101104798180024+$0.15873878885815/kw-mon)
= $231,137

The 77% availability percentage is the estimated Helms plant availability based on historical data from year 2018 to 2022.

d. Can you explain the Generation Dmax and the Pump Cmax. Is there an additional cost associated with the 78 MW Cmax?
Helms has 3 units. The Generation Dmax for each unit for the base case is 404 MW. The uprate is to increase generation from 404 MW to 456 MW per unit. So in total, (456 MW – 404 MW) * 3 units = 52MW * 3 = 156 MW increment. Therefore the Base case for Dmax is 156 MW.

The 129 MW Low case represent ______ [to be filled].

The current Cmax Pump for Helms is 300MW per unit. The increase of 52 MW (from 404 to 456 MW) per unit on the Dmax Generation side is equivalent to 13% increase (52MW / 404 MW = 13%). If the Pump Cmax follows the same increase proportionally which allows the Helms facility to derive optimal revenue, then it would mean an increase of (300 MW * 13%) * 3 Units = 39MW * 3 Units = 117 MW. However, to reflect common transmission limitations, the modeling assumed only two units could pump simultaneously. Therefore 117 MW * (2/3) = 78 MW. This is the 78 MW Increase case for Pump Cmax as shown in the table here:

	Base	Low
Gen /Dmax:	156 MW	129 MW
	Same:	Increase:
Pump/Cmax	0 MW	78 MW

e.

7. Is it possible to get a copy of the Revenue Requirements model that is used to as the basis for the cost calculations provided in the Consolidated Results Workbook? Provided

8. Ancillary service value is applied to the Uprate project evaluation. It doesn't appear that there is any ancillary service value applied to the MTR offers. Is this attributed to the duration of the storage. If not, what is the basis for including ancillary service value in the Uprate case?

   The MTR offers were all PPAs. Those PPAs had energy settlement provisions, where PG&E received a benefit based upon a formula in the contract and energy prices. That provision did not include any A/S benefits or any benefits based upon A/S prices. As PG&E is the scheduling coordinator for Helms, PG&E gets those benefits directly from the CAISO.

9. Please verify that the input assumptions used are the same for the analysis of the Uprate option and the MTR 3 evaluation results.

   Confirmed: the forward prices and ELCC assumptions were consistent across the MTR 3 RFO and the Helms analysis.

10. We would like to review the calculations for RA value as described in the Cost Effectiveness testimony to determine the local capacity value and the Flex Capacity value.

    Calculation is in workbook provided.

ATTACHMENT 22

PG&E Response to Cal Advocates Data Request 013, Question 12

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_013-Q012
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_013-Q012
Request Date:	October 22, 2024
Requester DR No.:	PGE-A2312014-013
Requesting Party:	Public Advocates Office
Requester:	Patrick Huber/Paul Worhach
Date Sent:	November 4, 2024
PG&E Witness(es):	Jenn Scott

The data request pertains to Application (A.) 23-12-014, *First Amended Application of Pacific Gas and Electric Company (U 39 E) to Recover Helms Uprate Costs (Application)*.

QUESTION 012

PG&E's response to CalAdvocates_005-Q004 states that Hitachi's model "…underestimates the actual output of existing 404 MW generator unit both at high and normal net head."[1] Please provide the following:

a. Actual output of existing 404 MW generator unit at high and normal net head. Include values for turbine output, generator output, and net head; and

b. Output of existing 404 MW generator unit at high and normal net head as estimated by Hitachi's model. Include values for turbine output, generator output, and net head.

ANSWER 012

a. Actual output of the existing 404 MW generator unit at high and normal head as follows.

Case	Gross Head (ft)[2]	Estimated Turbine Output (MW)[3]	Generator Output (MW)
Max (high)	1744 ft	415.31 MW	Max. 407 MW
Rated (normal)	1625 ft	412.24 MW	Max. 404 MW

1 HelmsUprateProject_DR_CalAdvocates_005-Q004.

2 Net Head is not measured and is a theoretical value that varies upon flow; therefore, data has been provided for gross head.

3 Based on estimated assumed generator efficiency of 98%.

b. The Hitachi Model estimates the following values for the existing Helms turbines:

Case	Net Head (ft)	Turbine Output (khp) (MW)	Estimated Generator Output (MW)[4]
Max (high)	1744 ft	Max. 555 khp (413.9 MW)	405.62 MW
Rated (normal)	1625 ft	Max. 508 khp (378.8 MW)	371.22 MW
		Rated 480 khp (357.9 MW)	350.74 MW

Hitachi's Model underestimates the performance of the existing Helms Units in two ways. One, it does not align with Helms existing unit performance at rated head (371 MW vs 404 MW). Two, it assumes a larger guide vane opening than what is required for the existing units to achieve 404 MW, which means the Hitachi model requires more flow through the unit to achieve 404 MW.

4 Based on estimated assumed generator efficiency of 98%.

ATTACHMENT 23

PG&E Response to Cal Advocates Data Request 013, Question 11.a, 11.c

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_013-Q011
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_013-Q011
Request Date:	October 22, 2024
Requester DR No.:	PGE-A2312014-013
Requesting Party:	Public Advocates Office
Requester:	Patrick Huber/Paul Worhach
Date Sent:	November 4, 2024
PG&E Witness(es):	Jenn Scott

The data request pertains to Application (A.) 23-12-014, *First Amended Application of Pacific Gas and Electric Company (U 39 E) to Recover Helms Uprate Costs (Application)*.

QUESTION 011

How did PG&E calculate the expected range for incremental capacities: 150-180 MW?

a. Was 150 MW derived as follows based on the Hitachi Turbine Study using the following calculations? Please confirm or correct.

   i. Turbine output at Hmax (Plan A) = 455 MW;[1]

   ii. Current nameplate capacity = 404 MW;

   iii. 455 – 404 = 51;

   iv. 51 * 3 = 153; and

   v. 153 is rounded to 150.

b. Was 180 MW derived as follows based on the Hitachi Turbine Study using the following calculations? Please confirm or correct.

   i. Turbine output at Hmax (Plan B) = 463 MW;[2]

   ii. Current nameplate capacity = 404 MW;

   iii. 463 – 404 = 59;

   iv. 59 * 3 = 177; and

   v. 177 is rounded to 180.

c. Was 180 MW derived as follows based on the Stantec Analysis of Alternatives, Alternative 3 using the following calculations? Please confirm or correct.

   i. Upper limit of turbine power output = 460 MW;

---

[1] Prepared Testimony, Chapter 2, Attachment A, *Hitachi Turbine Study*, p. 2-AtchA-4.

[2] Prepared Testimony, Chapter 2, Attachment A, *Hitachi Turbine Study*, p. 2-AtchA-4.

ii. 460 MW changed to 464 MW because 460 MW is too conservative;

iii. 464 – 404 = 60; and

iv. 60 * 3 = 180.

d. Does the incremental capacity refer to turbine output, generator output, or another value? Please specify.

e. At what net head are current, uprated, and incremental capacities evaluated? Please provide answer(s) in feet.

f. Are current, uprated, and incremental capacities calculated based on single-unit operation (multiplied by 3 to get plant total) or on three-unit operation?

ANSWER 011

a. The 150 MW incremental capacity was derived based on the Hitachi Turbine Study results of estimated maximum turbine output of 463 MW, which has a corresponding estimated maximum generator output of 453.74 MW (based on estimated assumed generator efficiency of 98%) and rounded to 454 MW. The maximum turbine output was used to reflect the lower end of the Uprate range because PG&E believes the Hitachi estimates for uprated turbine performance are conservative[3]. The 150 MW incremental capacity is then calculated as 454 * 3 = 1362 MW – 1212 MW = 150 MW. A turbine model test is required to confirm actual incremental capacity capability.

b. See response in c. below.

c. The 180 MW incremental capacity was derived based on multiple inputs. First, the Unit 2 generator was evaluated and determined to be capable of operating at 515.5 mega volt-ampere (MVA) or 464 MW and can receive an updated nameplate when operational testing is possible. Second, based on the Black and Veatch Feasibility Study and the Stantec Analysis of Alternatives, there is a general consensus that 460 MW individual generator output or 1380 MW plant generator output is achievable. PG&E believes the Hitachi estimates for uprated turbine performance, which is the limiting factor, to be conservative and therefore increased the maximum generator output by less than 1% from 460 MW to 464 MW to match the Unit 2 generator capability and from 1380 MW to 1392 MW for the total plant generator capability. The 180 MW incremental capacity is then calculated as 1392 MW – 1212 MW = 180 MW. A turbine model test is required to confirm actual incremental capacity capability.

d. The incremental capacity refers to the generator output. Current generator nameplate rating is 404 MW and the Uprated generator nameplate rating is estimated to range from 454 MW to 464 MW.

e. The existing Helms Units are capable of operating at 404 MW over a range of gross heads (1744 feet to 1600 feet or less; operational data was spot checked to understand possible range). Net Head is not measured and is a theoretical

[3] Please see PG&E's response to CalAdvocates_005-Q004 for more details.

value that varies upon flow; therefore, data has been provided for gross head. The Uprated MW capacity targets are based on maximum net head, in which Hitachi estimates maximum net head as 1744 feet and Stantec estimates maximum net head as 1719 feet. The incremental capacities represent the Uprated capacity targets minus the existing capacities and hence they are just a different way to represent the Uprated capacity targets.

f. Current and Uprated capacities are calculated based on single-unit operation (multiplied by 3 to get plant total) and on three-unit operation. The current units are capable of maximum operation of 407 MW, 407 MW, and 404 MW and they are capable of operating simultaneously at 1218 MW. The Uprated units are estimated to be capable of maximum operation of 454-464 MW each and they are estimated to be capable of operating simultaneously at 1362-1392 MW. The incremental capacities represent the Uprated capacity targets minus the existing capacities and hence they are just a different way to represent the Uprated capacity targets.

ATTACHMENT 24

PG&E Response to Cal Advocates Data Request 012, Question 3

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_012-Q003
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_012-Q003
Request Date:	October 4, 2024
Requester DR No.:	PGE-A2312014-012
Requesting Party:	Public Advocates Office
Requester:	Paul Worhach, Matthew George
Date Sent:	October 18, 2024
PG&E Witness(es):	Jenn Scott

QUESTION 003

If all the Three Transmission Projects are approved by CAISO as part of the 2024- 2025 TPP, would the Helms Uprate be eligible for Cluster 16?

ANSWER 003

Based on the information that CAISO has provided to date, the Helms Uprate point of interconnection is behind four transmission constraints with zero transmission plan deliverability (TPD) remaining. CAISO approval of the Three Transmission Projects would resolve the four transmission constraints by providing additional TPD. CAISO approval of the Three Transmission Projects either in the 2024-2025 TPP or the 2025-2026 TPP would add TPD prior to the Cluster 16 making it possible for the Helms Uprate to be selected for study. One thing that could prevent the Helms Uprate from being eligible for Cluster 16, even if the Three Transmission Projects are approved, is if the added TPD is fully allocated to existing CAISO Queue projects through the annual TPD allocation process prior to Cluster 16. This is why PG&E has indicated that it believes TPD will need to be reserved for the Helms Uprate project to be eligible. The information that CAISO has provided to date is subject to change. Constraint characteristics or project scopes could change based on CAISO's TPP and future study parameters.

ATTACHMENT 25

PG&E Response to TURN Data Request 003, Question 15

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	TURN_003-Q015		
PG&E File Name:	HelmsUprateProject_DR_TURN_003-Q015		
Request Date:	March 22, 2024	Requester DR No.:	#1
Date Sent:	April 5, 2024	Requesting Party:	The Utility Reform Network
PG&E Witness:	Jenn Scott	Requester:	Matthew Freedman

QUESTION 015

Regarding PG&E's assumptions related to Customer Interconnection Facilities it assumes will be necessary, please respond to the following questions:

a. How did PG&E develop the assumed level of Customer Interconnection Facilities?

b. Provide workpapers associated with the $12.17 million cost estimates for Customer Interconnection Facilities. Please provide in Excel.

c. Did PG&E consider a range of possible Customer Interconnection Facilities and costs before arriving at the level assumed in the application? If so, please provide the alternative interconnection assumptions considered and the costs associated with such activities.

ANSWER 015

a. The scope of work for interconnection will not be known until CAISO performs the interconnection study. The $12.7 million included in the project is for a potential scope of work that could include replacement of up to 6 circuit breakers and associated disconnect switches within the Gregg Substation (or similar level of work elsewhere on the grid). An estimate of $1.125 million per circuit breaker / disconnect switch was used for a total of $6.750 million. Also included in the cost is $150,000 for the CAISO Study. A 2.5% annual escalation was then applied to the $6.9 million, followed by application of 50% contingency, bringing up the total to $12.7 million.

b. Please see workpapers provide in response to Question 2: "HelmsUprateProject_DR_TURN_003-Q002Atch01". Cost forecast related to the Customer Interconnection Facilities can be found on tab "Ch.2 Uprate Cost", lines 60-65.

c. It is unknown what potential upgrades and costs will be required for Gregg Substation and the greater grid. This information will be provided in the CAISO Interconnection Study. PG&E Generation does not have the information necessary to consider what the potential upgrades may be beyond the potential replacement of the most directly related substation breakers and associated disconnect switches.

ATTACHMENT 26

PG&E Response to TURN Data Request 007, Question 3

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	TURN_007-Q003		
PG&E File Name:	HelmsUprateProject_DR_TURN_007-Q003		
Request Date:	May 24, 2024	Requester DR No.:	#7
Date Sent:	June 10, 2024	Requesting Party:	The Utility Reform Network
PG&E Witness:	Jenn Scott	Requester:	Matthew Freedman

QUESTION 003

In the response to TURN-03, Question 18, PG&E notes that the CAISO's 2023 Interconnection Process Enhancements Track 2 Final Proposal, the CAISO proposes to complete the development of the Cluster 15 base case and begin the cluster study by June 1, 2025. Please respond to the following questions about that response:

a. Is the June 1, 2025 date consistent with PG&E's expectations when it filed its application in this proceeding? If not, what was PG&E's assumption when it filed its application in this proceeding? If the June 1, 2025 date is later than PG&E assumed, how has this delay affected PG&E's schedule for completion of the Cluster 15 study?

b. How long does PG&E anticipate that the CAISO will take once it has completed the base case and begins the cluster study before the CAISO will provide PG&E with cost estimates for the interconnection upgrade requirements and costs?

c. Please explain why PG&E has stated at several places in its testimony that the CAISO process for Cluster 15 is anticipated to take two to three years? Is that the time that PG&E expects the CAISO to take once the base case is finished in May 2025?

d. Can PG&E proceed with construction of the interconnection upgrades prior to the completion of the Cluster 15 study?

ANSWER 003

a. No, PG&E's initial assumption when it filed this application was that the Cluster 15 study would begin in April 2024. The June 1, 2025, date is the most recent proposed start date for the CAISO Cluster 15 study. See PG&E's response to "HelmsUprateProject_DR_TURN_006-Q011" subpart c for more details.

b. CAISO will provide high level scope, schedule, and cost for all interconnection modifications at the completion the first phase of the Cluster 15 study (Nov. 2025). The scope, schedule, and cost will be refined at the completion of the Cluster 15 Re-study (May 2026) and will be finalized at the completion of the Facility Study (Aug. – Nov. 2026).

c. The CAISO Interconnection process is changing. The estimate for CAISO to complete the interconnection study under the old process was 2-3 years based on

California ISO

Criteria for Independent Study Process Eligibility

A project submitting an Interconnection Request application in the Independent Study Process (ISP) must demonstrate that the cluster process cannot accommodate the requested Commercial Operation Date (COD).

As part of this demonstration, any relevant documentation must be provided with the Interconnection Request application in order to satisfy the criteria for Independent Study Process eligibility as outlined in Appendix DD section 4.1.1. An Interconnection Request application that has not provided the documentation will be considered incomplete. The CAISO will review the documentation and notify the Interconnection Customer if the criteria has been satisfied.

In addition, once an ISP Interconnection Request application has been submitted for a project, COD extensions for Interconnection Requests under the ISP process will not be granted except for circumstances beyond the control of the customer.

Criteria for Independent Study Process Eligibility

1. The Interconnection Customer has obtained, or has demonstrated the ability to obtain, all regulatory approvals and permits needed to complete construction in time to meet the Generating Facility's requested Commercial Operation Date.
   PG&E will be able to obtain all regulatory approvals and permits needed to complete construction in time to meet the Helms PSP Uprate requested Commercial Operation Date. PG&E plans to start construction of the 1st unit in 2027 and expects the Commercial Operation Date of the 1st unit to be mid-Dec. 2027. Commercial Operation Dates for the 2nd and 3rd units will be sequential: 12/15/2028 and 12/15/2029.

   PG&E will be amending its current FERC License to include the additional generation capacity at Helms PSP. PG&E anticipates that approval of the FERC License amendment can be obtained 18-36 months after filing the amendment. PG&E is developing the FERC amendment application and plans to submit it by late 2023 or earlier.

   Based on feedback from the CPUC, received during PG&E's recent GRC proceeding, PG&E will be seeking approval from the CPUC for the Helms PSP Uprate project through a separate application. PG&E is developing the CPUC application and plans to submit it by late 2023 or earlier. It is reasonable to estimate that the duration to obtain approval from the CPUC is well within the time available prior to construction commencement.

   The other regulator that PG&E needs approval from for the Helms PSP Uprate project is CAISO, which is why PG&E is submitting this application for Independent Interconnection Study now. It is estimated that the study will take about 8-12 months and then any required interconnection modifications / upgrades will take another 2-3 years to complete. One risk to this schedule is completing any modifications that may require a 3-unit outage at Helms PSP. 3-unit outages requests must be closely coordinated with CAISO and they cannot always we accommodated. By applying now for the study, PG&E hopes there will be adequate time to complete the study and implement the required work prior Commercial Operation Date.

2. The Interconnection Customer is able to provide, or has demonstrated the ability to obtain, a purchase order for generating equipment specific to the proposed Generating Facility, or a statement signed by an officer or authorized agent of the Interconnection Customer demonstrating that the Interconnection Customer has a commitment for the supply of its major generating equipment in time to meet the Commercial Operation Date through a purchase agreement to which the Interconnection Customer is a party.
   PG&E will be able to obtain the generating equipment necessary to implement the Helms PSP Uprate in time to meet the Commercial Operation Date. Lead time for major material (turbine, transformer, and generator) is 2-3 years depending on the specific equipment. PG&E plans to issue equipment RFPs in late 2023. Based on PG&E's experience and recent communication with the major material providers, equipment delivery dates are achievable prior to the planned construction start.

3. The Interconnection Customer can provide reasonable evidence of adequate financing or other financial resources necessary to make the Interconnection Financial Security postings required in Sections 11.2 and 11.3.
   PG&E has adequate financing to make the required Financial Security postings required in Sections 11.2 and 11.3. Please see PG&E's 10-K (Annual Report) for period ending 12/31/22 from PGE.COM and found via the link below.

   https://d18rn0p25nwr6d.cloudfront.net/CIK-0001004980/70d15bb3-a51f-494a-bd25-79184a126c4d.pdf

4. The Point of Interconnection proposed by the Interconnection Customer must be to either: (1) an existing facility on the CAISO Controlled Grid that does not require any expansion in order to accommodate the interconnection of the Generating Facility; or (2) a facility approved in the Transmission Planning Process or identified as necessary through Interconnection Studies performed for other Interconnection Customers that is fully permitted, is under construction at the time the Interconnection Request is made, and is expected to be in service by the requested Commercial Operation Date of the Generating Facility.
   The Point of Interconnection for the Helms PSP Uprate is an existing facility on the CAISO Controlled Grid. Helms PSP utilizes 2 existing 230kV Gen-tie transmission lines that extend from Helms Switchyard to Gregg Substation in Fresno. The same interconnection will be used to transmit the generation from the Helms PSP Uprate.

5. With respect to any Reliability Network Upgrades that are anticipated to be needed to interconnect the Generating Facility, and that are already part of an existing plan of service or have been identified as necessary through Interconnection Studies performed for other Interconnection Customers, or have

been identified in the Transmission Planning Process, such Reliability Network Upgrades must be either in service or under construction and have a completion date no later than the requested Commercial Operation Date of the Generating Facility.

PG&E Hydro is not aware of any Reliability Network Upgrades that are needed to interconnect Helms PSP Uprate project. It is unknown if this Independent Interconnection Study will result in identification of any Reliability Network Upgrades.

how long it was taking to complete the Cluster 14 study (3 years). CAISO has proposed changes to the process, including schedule duration changes. Based on the latest proposal from CAISO, PG&E now expects that the CAISO will take fourteen - seventeen months to complete the Interconnection Study (Cluster 15 Study, Re-study, and Facility Study). See PG&E's response to "HelmsUprateProject_DR_TURN_006-Q011" subpart c for more details.

d. No, PG&E does not believe it can proceed with construction of interconnection upgrades prior to completion of the Interconnection Study. With that said, there has been a process in the past that allows acceleration of the engineering and procurement portion of the work to proceed while the study is being finalized. The process involved entering into an Engineering and Procurement Agreement, which could enable the project team to be established, engineering to proceed, and long lead material to be purchased prior to finalization of the Interconnection Study.

ATTACHMENT 27

PG&E Response to Cal Advocates Data Request 002, Question 3, Attachment 1

California ISO

Criteria for Independent Study Process Eligibility

A project submitting an Interconnection Request application in the Independent Study Process (ISP) must demonstrate that the cluster process cannot accommodate the requested Commercial Operation Date (COD).

As part of this demonstration, any relevant documentation must be provided with the Interconnection Request application in order to satisfy the criteria for Independent Study Process eligibility as outlined in Appendix DD section 4.1.1. An Interconnection Request application that has not provided the documentation will be considered incomplete. The CAISO will review the documentation and notify the Interconnection Customer if the criteria has been satisfied.

In addition, once an ISP Interconnection Request application has been submitted for a project, COD extensions for Interconnection Requests under the ISP process will not be granted except for circumstances beyond the control of the customer.

Criteria for Independent Study Process Eligibility

1. The Interconnection Customer has obtained, or has demonstrated the ability to obtain, all regulatory approvals and permits needed to complete construction in time to meet the Generating Facility's requested Commercial Operation Date.
   PG&E will be able to obtain all regulatory approvals and permits needed to complete construction in time to meet the Helms PSP Uprate requested Commercial Operation Date. PG&E plans to start construction of the 1st unit in 2027 and expects the Commercial Operation Date of the 1st unit to be mid-Dec. 2027. Commercial Operation Dates for the 2nd and 3rd units will be sequential: 12/15/2028 and 12/15/2029.

   PG&E will be amending its current FERC License to include the additional generation capacity at Helms PSP. PG&E anticipates that approval of the FERC License amendment can be obtained 18-36 months after filing the amendment. PG&E is developing the FERC amendment application and plans to submit it by late 2023 or earlier.

   Based on feedback from the CPUC, received during PG&E's recent GRC proceeding, PG&E will be seeking approval from the CPUC for the Helms PSP Uprate project through a separate application. PG&E is developing the CPUC application and plans to submit it by late 2023 or earlier. It is reasonable to estimate that the duration to obtain approval from the CPUC is well within the time available prior to construction commencement.

   The other regulator that PG&E needs approval from for the Helms PSP Uprate project is CAISO, which is why PG&E is submitting this application for Independent Interconnection Study now. It is estimated that the study will take about 8-12 months and then any required interconnection modifications / upgrades will take another 2-3 years to complete. One risk to this schedule is completing any modifications that may require a 3-unit outage at Helms PSP. 3-unit outages requests must be closely coordinated with CAISO and they cannot always we accommodated. By applying now for the study, PG&E hopes there will be adequate time to complete the study and implement the required work prior Commercial Operation Date.

2. The Interconnection Customer is able to provide, or has demonstrated the ability to obtain, a purchase order for generating equipment specific to the proposed Generating Facility, or a statement signed by an officer or authorized agent of the Interconnection Customer demonstrating that the Interconnection Customer has a commitment for the supply of its major generating equipment in time to meet the Commercial Operation Date through a purchase agreement to which the Interconnection Customer is a party.
   PG&E will be able to obtain the generating equipment necessary to implement the Helms PSP Uprate in time to meet the Commercial Operation Date. Lead time for major material (turbine, transformer, and generator) is 2-3 years depending on the specific equipment. PG&E plans to issue equipment RFPs in late 2023. Based on PG&E's experience and recent communication with the major material providers, equipment delivery dates are achievable prior to the planned construction start.

3. The Interconnection Customer can provide reasonable evidence of adequate financing or other financial resources necessary to make the Interconnection Financial Security postings required in Sections 11.2 and 11.3.
   PG&E has adequate financing to make the required Financial Security postings required in Sections 11.2 and 11.3. Please see PG&E's 10-K (Annual Report) for period ending 12/31/22 from PGE.COM and found via the link below.

   https://d18rn0p25nwr6d.cloudfront.net/CIK-0001004980/70d15bb3-a51f-494a-bd25-79184a126c4d.pdf

4. The Point of Interconnection proposed by the Interconnection Customer must be to either: (1) an existing facility on the CAISO Controlled Grid that does not require any expansion in order to accommodate the interconnection of the Generating Facility; or (2) a facility approved in the Transmission Planning Process or identified as necessary through Interconnection Studies performed for other Interconnection Customers that is fully permitted, is under construction at the time the Interconnection Request is made, and is expected to be in service by the requested Commercial Operation Date of the Generating Facility.
   The Point of Interconnection for the Helms PSP Uprate is an existing facility on the CAISO Controlled Grid. Helms PSP utilizes 2 existing 230kV Gen-tie transmission lines that extend from Helms Switchyard to Gregg Substation in Fresno. The same interconnection will be used to transmit the generation from the Helms PSP Uprate.

5. With respect to any Reliability Network Upgrades that are anticipated to be needed to interconnect the Generating Facility, and that are already part of an existing plan of service or have been identified as necessary through Interconnection Studies performed for other Interconnection Customers, or have

been identified in the Transmission Planning Process, such Reliability Network Upgrades must be either in service or under construction and have a completion date no later than the requested Commercial Operation Date of the Generating Facility.

PG&E Hydro is not aware of any Reliability Network Upgrades that are needed to interconnect Helms PSP Uprate project. It is unknown if this Independent Interconnection Study will result in identification of any Reliability Network Upgrades.

ATTACHMENT 28

PG&E Response to TURN Data Request 003, Question 17

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	TURN_003-Q017		
PG&E File Name:	HelmsUprateProject_DR_TURN_003-Q017		
Request Date:	March 22, 2024	Requester DR No.:	#1
Date Sent:	April 12, 2024	Requesting Party:	The Utility Reform Network
PG&E Witness:	Kurt Hansen	Requester:	Matthew Freedman

QUESTION 017

Assume that the costs of Network Upgrades that are ultimately determined by CAISO are greater than $15 million. Would this result in an increase in the cost cap for the Helms Uprate? If so, how would this occur. Please explain your response.

ANSWER 017

As described in Chapter 3, the costs for Network Upgrades are recovered through FERC-approved transmission rates. As such, these costs are not included in the Cost Recovery Cap proposed in this application. However, for full transparency, PG&E proposes to submit a Tier 1 Advice Letter to inform the Commission and stakeholders of the full scope of the Phase 2 Interconnection Study results, including those for reimbursable network upgrades, once that study is complete.

ATTACHMENT 29

PG&E Response to TURN Data Request 003 Question 15

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	TURN_003-Q015		
PG&E File Name:	HelmsUprateProject_DR_TURN_003-Q015		
Request Date:	March 22, 2024	Requester DR No.:	#1
Date Sent:	April 5, 2024	Requesting Party:	The Utility Reform Network
PG&E Witness:	Jenn Scott	Requester:	Matthew Freedman

QUESTION 015

Regarding PG&E's assumptions related to Customer Interconnection Facilities it assumes will be necessary, please respond to the following questions:

a. How did PG&E develop the assumed level of Customer Interconnection Facilities?

b. Provide workpapers associated with the $12.17 million cost estimates for Customer Interconnection Facilities. Please provide in Excel.

c. Did PG&E consider a range of possible Customer Interconnection Facilities and costs before arriving at the level assumed in the application? If so, please provide the alternative interconnection assumptions considered and the costs associated with such activities.

ANSWER 015

a. The scope of work for interconnection will not be known until CAISO performs the interconnection study. The $12.7 million included in the project is for a potential scope of work that could include replacement of up to 6 circuit breakers and associated disconnect switches within the Gregg Substation (or similar level of work elsewhere on the grid). An estimate of $1.125 million per circuit breaker / disconnect switch was used for a total of $6.750 million. Also included in the cost is $150,000 for the CAISO Study. A 2.5% annual escalation was then applied to the $6.9 million, followed by application of 50% contingency, bringing up the total to $12.7 million.

b. Please see workpapers provide in response to Question 2: "HelmsUprateProject_DR_TURN_003-Q002Atch01". Cost forecast related to the Customer Interconnection Facilities can be found on tab "Ch.2 Uprate Cost", lines 60-65.

c. It is unknown what potential upgrades and costs will be required for Gregg Substation and the greater grid. This information will be provided in the CAISO Interconnection Study. PG&E Generation does not have the information necessary to consider what the potential upgrades may be beyond the potential replacement of the most directly related substation breakers and associated disconnect switches.

ATTACHMENT 30

PG&E Response to Cal Advocates Data Request 004, Question 3

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_004-Q003		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_004-Q003		
Request Date:	April 4, 2024	Requester DR No.:	PGE-A2312014-004
Date Sent:	April 25, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Kurt Hansen	Requester:	Michael George/ Paul Worhach

QUESTION 003

PG&E's response to Public Advocates Office Data Request-PGE-A2312014-001, Question 28 states:

> "The decreased total water supply during droughts affects generation in lower value periods, which decreases annual total energy generation but does not affect availability to run when needed."

a. What hydrological conditions does PG&E assume in its Net Market Value (NMV) analysis?

b. How does PG&E account for decreases in annual total energy generation during drought years in its NMV analysis?

c. Explain PG&E's reasoning for whatever hydrological assumptions it makes in its NMV analysis.

ANSWER 003

a. For the NMV analysis, PG&E conservatively modeled the generation from the incremental capacity as a closed-loop pump-storage system. This means watershed run-off is not included in the incremental generation calculations. With this modeling simplification, hydrologic changes to watershed run-off are not required for the analysis.

   Hydrologic conditions were not used to adjust the incremental capacity of the two scenarios in the NMV analysis. PG&E included a conservative lower-case scenario to bookend the range of possible incremental capacity increase.

   The price forecast used in the NMV analysis to value the generation revenue and the pumping cost reflect a range of CAISO-wide hydro generation assumptions due to different hydrologic conditions. Beyond the hydro generation assumptions, the fundamental analysis used to forecast prices includes many other inputs such as load, resource additions and retirements, gas prices, etc. PG&E's price forecast averages three different price scenarios.

b. As explained in answer (a), because PG&E modeled the incremental capacity as a closed loop system, the NMV analysis did not account for decreased energy generation in drought years, nor increased energy generation in wet years.

c. See answer (a) for PG&E's reasoning regarding hydrological assumptions in the NMV analysis.

ATTACHMENT 31

PG&E Supplemental Response to TURN Data Request 006
Question 9

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	TURN_006-Q009		
PG&E File Name:	HelmsUprateProject_DR_TURN_006-Q009		
Request Date:	May 14, 2024	Requester DR No.:	#6
Date Sent:	May 24, 2024	Requesting Party:	The Utility Reform Network
PG&E Witness:	Kurt Hansen	Requester:	Matthew Freedman

QUESTION 009

Has PG&E performed any sensitivity analyses of the benefits and costs of the Uprate project under different long-term climate change assumptions or precipitation assumptions? If not, please explain why not.

ANSWER 009

PG&E's Net Market Value (NMV) analysis did not include sensitivity analyses related to long-term climate change or precipitation assumptions.

Hydrologic conditions were not used to adjust the incremental capacity of the two scenarios in the NMV analysis. For the NMV analysis, PG&E conservatively modeled the generation from the incremental capacity as a closed-loop pump-storage system. This means watershed run-off is not included in the incremental generation calculations. With this modeling simplification, hydrologic changes to watershed run-off are not required for the analysis.

The NMV analysis did not adjust for net head for changing hydrologic conditions. Helms has much higher storage capacity than is typical for a pumped storage facility and rarely reaches the minimum head. Courtright and Wishon reservoirs are operated such that net head remains above 1,600 feet most of the year, enabling each Helms unit to achieve 404 MW (nameplate capacity) most of the year. Due to the large storage capacity of Courtright and Wishon, it is anticipated that similar operational protocol will be implemented for the Helms Uprated units, enabling each Helms Uprated unit to achieve between 454 and 464 MW most of the year.

PG&E's NMV analysis did include a lower-case capacity scenario to bookend the range of possible incremental capacity increase.

The price forecast used in the NMV analysis to value the generation revenue and the pumping cost reflect a range of CAISO-wide hydro generation assumptions due to different hydrologic conditions. Beyond the hydro generation assumptions, the fundamental analysis used to forecast prices includes many other inputs such as load, resource additions and retirements, gas prices, etc. PG&E's price forecast averages three different price scenarios.

ATTACHMENT 32

PG&E Response to Cal Advocates Data Request 001
Question 28

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_001-Q028		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_001-Q028		
Request Date:	March 6, 2024	Requester DR No.:	PGE-A2312014-001
Date Sent:	March 20, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jennifer Scott	Requester:	Michael George/ Paul Worhach

SUBJECT: DATA REQUEST NO. PGE-A2312014-001

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* (Application).

QUESTION 028

Have the Joint Applicants conducted any analysis forecasting potential drought impacts on the future generating capacity of the Helms facility?

a. If so, provide the results of that analysis and any relevant workpapers.

ANSWER 028

No formal studies have been performed to evaluate drought impact on Helms, but historical review indicates no significant impact on capacity. During droughts, Helms typically remains fully available to run during the highest value hours of the day due to the amount of reservoir storage in Courtright and Wishon Reservoirs, which allows optimization of Helms dispatch plans in response to snow survey results and forecast water supply. The decreased total water supply during droughts affects generation in lower value periods, which decreases annual total energy generation but does not affect availability to run when needed.

ATTACHMENT 33

PG&E Response to TURN Data Request 008
Question 3

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	TURN_008-Q003		
PG&E File Name:	HelmsUprateProject_DR_TURN_008-Q003		
Request Date:	June 28, 2024	Requester DR No.:	#8
Date Sent:	July 15, 2024	Requesting Party:	The Utility Reform Network
PG&E Witness:	Jenn Scott	Requester:	Matthew Freedman

QUESTION 003

Please provide PG&E's current estimates for the beginning and ending dates for each activity listed in Figure 2-1. Please provide this in Excel.

ANSWER 003

Please refer to HelmsUprateProject_DR_TURN_003-Q006 Response and Attachment 01 and HelmsUprateProject_DR_TURN_005-Q001 Response for more details.

Please see attachment HelmsUprateProject_DR_TURN_008-Q003Atch01.

Schedule	Activity	Start Date	End Date
Agency Permitting	CPUC Application Process	12/20/2024	12/31/2025
	CAISO Cluster Study	6/1/2025	11/15/2026
	CAISO Interconnection Work	1/1/2027	3/31/2030
	FERC License Amendment	7/1/2023	12/31/2025
Design	Alternatives Analysis	1/1/2023	3/1/2024
	Design/Performance Criteria Development (Turbine)	1/6/2024	7/30/2024
	OEM Design - Turbine	11/26/2026	6/13/2027
	OEM Design - Generator	12/16/2026	7/3/2027
	OEM Design - Transformers	3/15/2025	9/30/2025
	Project Closeout	1/1/2032	12/31/2032
Execution	Contractor RFP/Bidding (Turbine Model Test)	6/29/2024	2/23/2025
	Major Materials Procurement (Turbine; including Model Test)	2/24/2025	12/14/28 (1st Unit) 9/20/2029 (2nd Unit) 5/18/2030 (3rd Unit)
	1st Unit Uprate Construction	2/12/2029	11/19/2029
	2nd Unit Uprate Construction	3/19/2030	12/24/2030
	3rd Unit Uprate Construction	4/23/2031	1/28/2032

ATTACHMENT 34

PG&E Response to Cal Advocates Data Request 001 Question 3

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response, 2024

PG&E Data Request No.:	CalAdvocates_001-Q003		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_001-Q003		
Request Date:	March 6, 2024	Requester DR No.:	PGE-A2312014-001
Date Sent:	March 20, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Mark Dean	Requester:	Michael George/ Paul Worhach

SUBJECT: DATA REQUEST NO. PGE-A2312014-001

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* (Application).

QUESTION 003

Provide the workpapers and models used for the calculation of the Net Market Value (NMV) of the Helms Uprate. Provide Excel worksheets with active cells and formulas.

ANSWER 003

In response to Question 3, PG&E has included in its response to this data request an Excel document titled "HelmsUprateProject_DR_CalAdvocates_001-Q003Atch01CONF", along with a confidentiality declaration titled "HelmsUprateProject_DR_CalAdvocates_001-Q003Atch02" signed by Mark Dean covering certain protected and confidential information found within that Excel document.

ATTACHMENT 35

PG&E Response to Cal Advocates Data Request 011 Question 2

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_011-Q002
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_011-Q002
Request Date:	October 2, 2024
Requester DR No.:	011
Requesting Party:	Public Advocates Office
Requester:	Paul Worhach, Matthew George
Date Sent:	October 23, 2024
PG&E Witness(es):	Kurt Hansen

QUESTION 002

In response to Public Advocates Data Request Public PGE-A2312014-003, Question ~~3~~2.b,[2] PG&E provided an NMV analysis for the higher and lower incremental uprate scenarios assuming that only the incremental Uprate work is eligible for the 30% investment tax credit (ITC).[3] Provide an update of this analysis corresponding to PG&E's Supplemental Testimony.

ANSWER 002

The attachments to this response contain CONFIDENTIAL information described in Declaration Supporting Confidential Designation dated Oct. 17, 2024.

Subject to and notwithstanding the objection stated in PG&E's response to Public Advocates Data Request Public PGE-A2312014-003, Question 2.b, and without conceding that the Lifecycle Replacement Work is a distinct project that is not included in or necessary to the Helms Uprate, PG&E and Cal Advocates previously met and conferred regarding the Public Advocates' original data response and agreed that PG&E would provide a supplemental response to Question 2.b that hypothetically assumed that only an incremental cost for the Helms Uprate, which would subtract a theoretical cost for the Lifecycle Replacement Work, received an investment tax credit. Subject to the same objections and based upon the prior outcome of the meet-and-confer with the Public Advocates, PG&E is now providing an update of the requested analysis reflecting the changes submitted in PG&E's Supplemental Testimony.

See attached HelmsUprateProject_DR_CalAdvocates_011-Q002Atch01CONF for the Result of Operations (RO) model for the $462 million Helms Uprate Cost with the ITC

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2 The original data request referred to Question 3.b. The Public Advocates' Office confirmed via email on October 3, 2024 that the reference should instead be to Question 2.b, and PG&E has made that change here.

3 PG&E Helms Uprate Project Data Response HelmsUprateProject_DR_CalAdvocates_003-Q002Supp02, June 6, 2024.

amount applied only to a hypothetical “incremental” Uprate cost. PG&E used the same RO model and inputs provided in Data Response HelmsUprateProject_DR_CalAdvocates_003-Q002Supp02 on June 6, 2024. We then modified the RO model to incorporate the changes of timing of interconnection costs and ITC, as discussed in PG&E’s Supplement Testimony served on September 30, 2024.

See attached HelmsUprateProject_DR_CalAdvocates_011-Q002Atch02CONF for the requested NMV analysis. Per the data request and unlike the NMV analysis presented in the original application filing, ITC is applied only to a hypothetical “incremental” Uprate cost and not the total project cost (i.e. inclusive of both uprate and lifecycle replacement work). Additionally, this revised NMV analysis uses the revenue requirement that was calculated in the RO model after incorporating the changes in timing of interconnection costs and the ITC, as discussed in PG&E’s Supplemental Testimony served on September 30, 2024. Otherwise, the capital revenue requirement for this scenario was calculated using the same RO model as for the filing scenario, with total project costs equivalent for both the higher and lower capacity scenarios. All other assumptions, such as dates, discount rate, volumes, dispatch, and forward curves are unchanged from the NMV analysis underlying the application.

Under these reduced ITC assumptions, the NMV of the two cases is decreased.

ATTACHMENT 36

Supplemental PG&E Response to Cal Advocates Data Request 003, Question 2.b

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_003-Q002		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_003-Q002Supp01		
Request Date:	March 29, 2024	Requester DR No.:	PGE-A2312014-003
Date Sent:	April 22, 2024 (Original) May 24, 2024 (Supplemental)	Requesting Party:	Public Advocates Office
PG&E Witness:	Will Ou, Mark Dean	Requester:	Michael George/ Paul Worhach

QUESTION 002

In response to Public Advocates Office Data Request-PGE-A2312014-001, Question 3, PG&E provided the Excel worksheet HelmsUprateProject_DR_CalAdvocates_001-Q003Atch01CONF.xlsx with a Net Market Value (NMV) analysis of the Helms Uprate Project. The NMV analysis shows that the Higher Incremental Capacity scenario has a Net Energy benefit that is four times that of the Lower Incremental scenario, despite having only 21% more capacity.

a. Explain why the Net Energy benefit of the Lower Incremental Capacity scenario is significantly lower than the Net Energy benefits of Higher Incremental Capacity Scenario. What operational or technical constraints for the Lower Incremental Capacity scenario contribute to the difference?

b. Provide the same NMV analysis of the Helms Uprate project for the Higher Incremental Capacity and Lower Incremental Capacity scenarios assuming that only the incremental Helms Uprate work for the 150-180 MW, and not the Lifecycle Replacement work, is eligible for the 30% investment tax credit (ITC).

ANSWER

a. The two scenarios differ both in generation capacity and in pumping capacity, as summarized in the table below:

Scenario	Incremental Generation Capacity	Incremental Pumping Capacity
1: Higher Incremental Capacity	156 MW	78 MW
2: Lower Incremental Capacity	129 MW	0 MW

.

Scenario 1 (Higher Incremental Capacity) has approximately proportional increases for both generation and pumping capacity as compared to the existing Helms facility, which allows the plant to operate with a similar pattern as the existing facility but at higher volumes.

Scenario 2 (Lower Incremental Capacity) is modeled with 27 MW less incremental generating capacity as compared to Scenario 1. However, importantly, the biggest difference is that Scenario 2 reflects a conservative assumption that there would be **no** incremental increase in pumping capacity. This modeling assumption means that Scenario 2 pumps less at the lowest-price hours as compared to Scenario 1. Instead, Scenario 2 pumps more in the higher-price shoulder hours to supply the stored water to power the incremental generating capacity. This leads to a lower margin on the incremental cycling of the plant for Scenario 2.

Figures 1 and 2 show smoothed patterns (for year 2035) of modeled energy dispatch (generation) and pumping at different energy price levels. Three curves are shown: the two scenarios and the existing Helms facility ("Base"). Figure 1 shows at the higher energy prices, the scenarios dispatching roughly proportional to their increased generation capacity (i.e., the red line is slightly under the blue line). Figure 2 shows that while the Scenario 1 can pump incrementally during the lowest-price hours, Scenario 2 must pump more often at higher-price hours (i.e., for the lowest-price hours, the red line is significantly lower than the blue line).

Figure 1: Helms' Dispatch versus Energy Price

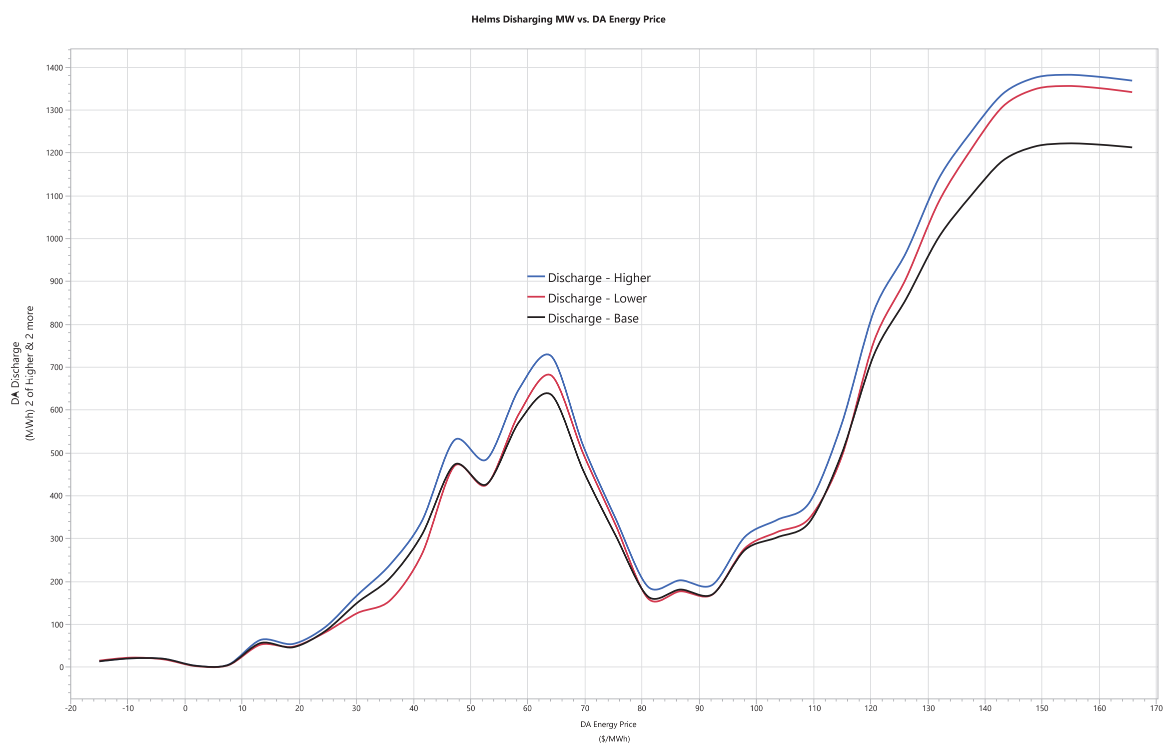
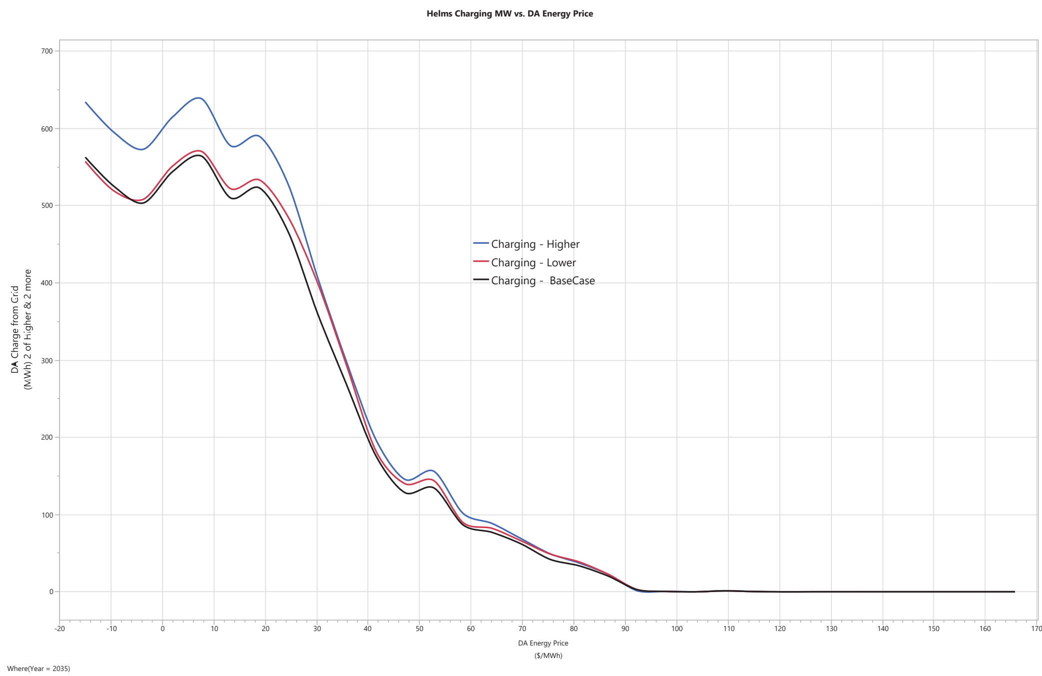


Figure 2: Helms' Pumping versus Energy Price



b. PG&E objects to this data request because the requested analyses have not been performed.

The requested analyses assume only the imputed incremental cost of the Helms Uprate (above that of the Lifecycle Replacement Cost, LRC) would be eligible for the ITC. However, the Helms Uprate Cost is not simply "incremental to" the LRC – it includes the LRC as part of the scope and cannot be accomplished without the LRC. They are not separate scopes.

Moreover, if PG&E proceeds with the Helms' Uprate, the actual LRC and incremental capital cost will not be known. The forecasted LRC and Net Incremental Capacity Cost presented in the prepared testimony are developed for the purpose of analyzing the cost effectiveness of the Uprate. If approved, PG&E will complete the engineering work and construct the Uprate project, and the actual Uprate cost will be known. The completion of the engineering work and construction of the alternative Lifecycle Replacement will not be done, and, therefore, that cost will not be known.

ANSWER (SUPPLEMENTAL 01)

The attachments to this response contain CONFIDENTIAL information described in Declaration Supporting Confidential Designation dated May 23, 2024.

Subject to and notwithstanding the objection stated in subsection (b) above, and without conceding that the Lifecycle Replacement Work is a distinct project that is not included in necessary to the Helms Uprate, PG&E and Cal Advocates met and conferred regarding this data response and agreed that PG&E would provide a further response that hypothetically assumed that only an incremental cost for the Helms Uprate, which would subtract a theoretical cost for the Lifecycle Replacement Work, received an investment tax credit. PG&E provides the requested analysis in this supplemental data response.

See attached HelmsUprateProject_DR_CalAdvocates_003-Q002Supp01Atch01 for the Result of Operations (RO) model for the $462 million Helms Uprate Cost with the ITC amount applied only to a hypothetical "incremental" Uprate cost.

See attached HelmsUprateProject_DR_CalAdvocates_003-Q002Supp01Atch02CONF for the requested NMV analysis. Per the data request and unlike the NMV analysis presented in the original application filing, ITC is applied only to a hypothetical "incremental" Uprate cost and not the total project cost (i.e. inclusive of both uprate and lifecycle replacement work). Otherwise, the capital revenue requirement for this scenario was calculated using the same RO model as for the filing scenario, with total project costs equivalent for both the higher and lower capacity scenarios. All other assumptions, such as dates, discount rate, volumes, dispatch, and forward curves are unchanged from the NMV analysis underlying the application.

Under these reduced ITC assumptions, the NMV of the High Capacity case remains positive, while the Lower Capacity case became slightly negative.

ATTACHMENT 37

PG&E Response to Cal Advocates Data Request 008
Question 4

PACIFIC GAS AND ELECTRIC COMPANY
Helms Uprate Project
Application 23-12-014
Data Response

PG&E Data Request No.:	CalAdvocates_008-Q004		
PG&E File Name:	HelmsUprateProject_DR_CalAdvocates_008-Q004		
Request Date:	June 20, 2024	Requester DR No.:	PGE-A2312014-008
Date Sent:	July 3, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	Jenn Scott	Requester:	Matthew George/ Paul Worhach

The data request pertains to Application (A.) 23-12-014, *Application of Pacific Gas and Electric Company (U 39 E) and Pacific Generation LLC to Recover Helms Uprate Costs* ("Application"), as well as the Analysis of Alternatives Helms Uprate prepared by Stantec in March 2024 ("Analysis of Alternatives"). "Hitachi Plan A" and "Hitachi Plan B" refer to Plan A and Plan B as described in the Application, Chapter 2, Attachment A (Hitachi Turbine Study).

Regarding the Application, Tables 2-1 and 2-2:

QUESTION 004

Please explain the application of a 50% contingency to estimate the Helms Lifecycle Replacement Cost in Table 2-2 of the Application. How was that contingency amount determined?

ANSWER 004

Please see data responses related to questions regarding contingency from CalAdvocates_003 Data Request for more detailed explanations.

The contingency amount of 50% was applied to the Helms Lifecycle Replacement Cost for same reasons it was applied to the Helms Uprate Cost. The Helms Lifecycle Replacement Cost estimate is a Class 5 cost estimate and considered to be high complexity.

The Class 5 AACE Estimate Uncertainty recommended percentage ranges from 20% for Low Complexity to 100% for High Complexity. The Class 4 AACE Estimate Uncertainty recommended percentage ranges from 15% for Low Complexity to 50% for High Complexity. The team applied a single calculation for total contingency which represents the total AACE Estimate Uncertainty plus total Value of Risk. The team used professional judgement to determine a total contingency of 50% was adequate for the Lifecycle Replacement work.

A 50% total contingency was determined to be more appropriate for the Helms Lifecycle Replacement work than a 100% total contingency when the team considered that similarly complex work had been performed at Helms in the past. It is estimated that there are less unidentified risks than a typical high complexity Class 5 project because of the similar complex outage work performed over the past 20 years at Helms.

A 50% total contingency is within the recommended percentage range for Class 5 AACE Estimate Uncertainty and on the higher end of the recommended percentage range for Class 4 AACE Estimate Uncertainty. The team's professional judgement caused them to feel that 100% AACE Estimate Uncertainty on top of the Value of Risks was too much contingency to justify for the level of scope development and cost estimate references, so they lowered the total contingency to a value that was reasonable based on the team's experience and judgement.

ATTACHMENT 38

PG&E Advice Letter E-7331

Pacific Gas and Electric Company

Sidney Bob Dietz II
Director
Regulatory Relations

Pacific Gas and Electric Company
300 Lakeside Drive
Oakland, CA 94612

July 19, 2024

Advice 7331-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: Amendment to Mid-Term Reliability Agreement approved in Advice Letter 6477-E

I. Purpose

Pursuant to Decision (D.) 21-06-035, Pacific Gas and Electric Company (PG&E or the Utility) requests approval of an amendment to a transaction resulting from PG&E's 2021 Mid-Term Reliability Request for Offers – Phase 1 (MTR RFO – Phase 1) that was presented in Advice Letter 6477-E and approved by the California Public Utilities Commission (Commission or CPUC) in Resolution E-5202 on April 21, 2022.

The amendment included in this Advice Letter is necessary for PG&E to continue to make progress to meet the incremental September Net Qualifying Capacity (NQC) procurement requirements mandated in D.21-06-035. For the reasons described herein, the amendment presented in this advice letter is reasonable and in the interest of customers, and thus should be approved.

II. Background

On June 30, 2021, the Commission issued D.21-06-035, which took a number of steps to address the mid-term reliability needs of the electricity system within the California Independent System Operator Corporation's (CAISO) operating system beginning in 2023 to meet the expected increased demand for electricity on the system, the pending retirement of the Diablo Canyon Power Plant (DCPP) and the planned retirement of once-through-cooling (OTC) thermal plants in Southern California. In D.21-06-035, the Commission ordered incremental procurement of 11,500 MWs of additional NQC resources, of which PG&E is responsible for 2,302 MWs for its bundled service customer portion. Specifically, D.21-06-035 ordered procurement of resources to deliver at least 2,000 MW by August 1, 2023, an additional 6,000 MW by June 1, 2024, an additional 1,500 MW by June 1, 2025, and an additional 2,000 MW by June 1, 2026. D.21-06-035, also ordered that at least 2,500 MW of the resources procured by the load serving entities (LSEs) collectively, between 2023 and 2025, be from zero-emission resources that generate electricity, or generation resources paired with storage, or demand response, to replace the current supply of energy from the DCPP and ensure there is no resultant increase in GHG emissions upon its retirement.

Additionally, D.21-06-035 and the subsequent Commission Energy Division memorandum with guidance for incremental effective load carrying capacity (ELCC) values to use for mid-term reliability procurement compliance,[1] affirm that the investor-owned utilities (IOU) are to continue to act as the backstop procurement agents, under the framework adopted in D.20-12-044, for Community Choice Aggregators (CCAs) and Energy Service Providers (ESPs) that fail to meet their procurement responsibilities of incremental system resources under D.21-06-035.

D.21-06-035 outlined eligibility requirements for resources to meet the procurement obligations and requirements for the solicitation, including types of resources eligible (e.g., eligibility of imports) and minimum contract lengths.

In accordance with D.21-06-035, on January 21, 2022, PG&E sought approval for the Corby Energy Storage Project (Project) agreement along with eight other agreements, which the Commission approved on April 21, 2022.[2]

PG&E sought approval for pricing amendments for four of the other Phase 1 agreements, on September 23, 2022, which the Commission approved on December 1, 2022[3]. PG&E sought approval for a pricing amendment for an additional Phase 1 agreement on December 28, 2023, which the Commission approved on March 21, 2024.[4]

Since the agreement was executed, Corby Energy Storage, LLC (Corby) informed PG&E that it would not be able to meet the required 2024 online date of the Project until 2027 due to interconnection issues. Corby also indicated it would not be able to develop the Project at the original price and would need a price increase to remain viable. Corby requested an amendment to its agreement to allow it to complete the Project which, when developed, will contribute to system reliability. The resulting amendment is described below.

A. Negotiation Background

Interconnection: Since the agreement was executed in 2021, Corby has experienced unexpected Participating Transmission Owner (PTO) delays in relation to the completion of network upgrades identified in its interconnection agreement. The counterparty has requested that the project online date be pushed out by three years to remedy these ongoing issues. Absent an extension for the Project online date, the counterparty has

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[1] Energy Division staff e-mailed parties on October 22, 2021, with an updated Incremental ELCC Study for Mid-term Reliability Procurement, by E3 and Astrapé. The materials can be found on [IRP Procurement Track (ca.gov)]
[2] CPUC Res. E-5202
[3] CPUC Res. E-5243
[4] CPUC Res. E-5312

expressed that it would not be able to meet the current required online date of the Project, which will result in Corby having to default under its agreement with PG&E.

Pricing: Since the agreement was executed in 2021, there have been unprecedented industry-wide market changes and inflationary pressure on Project costs. As a result, Corby has requested a price increase under its agreement with PG&E for the Project in order for the Project to remain commercially viable. The main drivers cited for the increased costs include:

- Battery prices have risen significantly due to dramatic increases in commodity prices for lithium carbonate and metals used in manufacturing lithium-ion batteries. This impacts both initial construction costs and ongoing augmentation costs to maintain capacity. Although lithium prices have dropped from peak levels, the battery procurement costs for Corby were incurred at prices higher than anticipated when the contract was executed in order to procure modules in time to meet the project milestones;
- Continued supply chain constraints;
- Balance of systems costs have been increasing due to high inflation affecting materials and labor costs; and
- Cost of capital has been increasing as the Federal Reserve has been raising interest rates to combat inflation.

Absent the price increase, Corby has expressed that it would not be able to build the Project and would default under its agreement with PG&E. In considering the amendment, PG&E has negotiated aggressively with the counterparty with respect to the price increase and has conducted due diligence on the proposed price increase, assessing what kind of mitigation actions Corby has taken and how much of the cost burden is being passed to the Utility. Appendix A to this advice letter further describes the negotiations process.

B. SUMMARY OF AMENDED AGREEMENT

The amended agreement is as follows:

Counterparty (Project Name)	Technology	Original Initial Delivery Date	Updated Initial Delivery Date	Term (Years)	Nameplate Size (MW)	
Corby Energy Storage, LLC	Lithium Ion Batteries	6/1/2024	8/1/2027	15	125	125

See confidential Appendix A for a further description of the Amendment.

III. Procurement Review Group/Cost Allocation Mechanism

PG&E notified the Procurement Review Group about the amendment on May 9, 2023, and notified the Procurement Review Group of the intent to execute the amendment on March 22, 2024.

IV. Confidentiality Treatment

In support of this advice letter, PG&E has provided the confidential information listed below. This information is being submitted in the manner directed by D.08-04-023 establishing procedures for complying with D.06-06-066 to demonstrate the confidentiality of the material and to invoke the protection of confidential utility information provided under Public Utilities Code section 454.5(g) or the IOU Matrix, Appendix 1 of D.06-06-066 and Appendix C of D.08-04-023. The Declaration of Mark Muranishi seeking confidential treatment of confidential materials provided herein is being submitted concurrently with this advice letter.

In accordance with GO 96-B, a copy of PG&E's Proposed Protective Order is attached as Appendix C.

Appendices

Appendix A:	Key Aspects to the Amendment RAA w/ES Amendment (Confidential)
Appendix B:	Corby Energy Storage, LLC – Corby Storage (LT RAA w/ES) Amendment (Confidential)
Appendix C:	Proposed Protective Order

V. Protests

Anyone wishing to protest this submittal may do so by letter sent electronically via E-mail, no later than **August 8, 2024**, which is 20 days after the date of this submittal. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
E-mail: EDTariffUnit@cpuc.ca.gov

The protest shall also be electronically sent to PG&E via E-mail at the address shown below on the same date it is electronically delivered to the Commission:

Sidney Bob Dietz II
Director, Regulatory Relations
c/o Megan Lawson
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order (GO) 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name and e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (GO 96-B, Section 3.11).

VI. Effective Date

Pursuant to GO 96-B, Rule 5.3, this advice letter is submitted with a Tier 3 designation. PG&E requests that this advice letter become effective upon Commission approval.

VII. Notice

In accordance with GO 96-B, Section IV, a copy of this advice letter is being sent electronically to parties shown on the attached list and the parties on the service list for R.20-05-003. Address changes to the GO 96-B service list should be directed to PG&E at the email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Sidney Bob Dietz II
Director, Regulatory Relations
CPUC Communications

cc: Service List R.20-05-003
Nick Dahlberg – Energy Division

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (U 39 E)

Utility type:
- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Michael Finnerty
Phone #: (279) 789-6216
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: michael.finnerty@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 7331-E

Tier Designation: 3

Subject of AL: Amendment to Mid-Term Reliability Agreement approved in Advice Letter 6477-E

Keywords (choose from CPUC listing): Compliance, Reliability

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.21-06-035

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? ☑ Yes ☐ No

If yes, specification of confidential information: see confidential declaration and matrix.
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information: Mark Muranishi, Mark.Muranishi@pge.com

Resolution required? ☑ Yes ☐ No

Requested effective date:

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission Energy Division Tariff Unit Email: EDTariffUnit@cpuc.ca.gov	Contact Name: Sidney Bob Dietz II, c/o Megan Lawson Title: Director, Regulatory Relations Utility/Entity Name: Pacific Gas and Electric Company Telephone (xxx) xxx-xxxx: Facsimile (xxx) xxx-xxxx: Email: PGETariffs@pge.com
	Contact Name: Title: Utility/Entity Name: Telephone (xxx) xxx-xxxx: Facsimile (xxx) xxx-xxxx: Email:

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

**PACIFIC GAS AND ELECTRIC COMPANY
ADVICE LETTER FOR APPROVAL OF CONTRACT
TERM AMENDMENT TO CORBYENERGY STORAGE
AGREEMENT**

**DECLARATION OF MARK MURANISHI
SEEKING CONFIDENTIAL TREATMENT
FOR CERTAIN DATA AND INFORMATION
CONTAINED IN PG&E'S ADVICE LETTER**

I, Mark Muranishi, declare:

1. I am a Director in the Structured Energy Transactions Department at Pacific Gas and Electric Company (PG&E). In this position, I am responsible for procurement of various electric resources and products including energy storage and renewable energy. This declaration is based on my personal knowledge of PG&E's practices and my understanding of the Commission's decisions protecting the confidentiality of market-sensitive information.

2. Based on my knowledge and experience, and in accordance with the Decisions 06-06-066, 08-04-023, and relevant Commission rules, I make this declaration seeking confidential treatment for certain data and information contained in PG&E's Advice Letter for approval of contract term amendment to the Corby Energy Storage Agreement.

3. Attached to this declaration is a matrix identifying the data and information for which PG&E is seeking confidential treatment. The matrix specifies that the material PG&E is seeking to protect constitutes confidential market sensitive data and information covered by D.06-06-066, Appendix 1, and Public Utilities Code §454.5(G). The matrix also specifies why confidential protection is justified. Further, the data and information: (1) is not already public; and (2) cannot be aggregated, redacted, summarized or otherwise protected in a way that allows partial disclosure. By this reference, I am incorporating into this declaration all of the explanatory text that is pertinent to my testimony in the attached matrix.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on July 19, 2024 at Oakland, California.

/s/

Mark Muranishi

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

ADVICE LETTER FOR APPROVAL OF CONTRACT TERM AMENDMENTS TO CORBY ENERGY STORAGE AGREEMENT
July 19, 2024

IDENTIFICATION OF CONFIDENTIAL INFORMATION

Redaction Reference	Category from D.06-06-066, Appendix 1, or Separate Confidentiality Order That Data Corresponds To	PG&E's Justification for Confidential Treatment	Length of Time
Confidential Appendices			
Appendix A: Detailed Summary of Amended Terms and Conditions and Negotiation Process	Item VII.B (Contracts and Power Purchase Agreements between utilities and non-Affiliated Third Parties (except RPS)), VIII.B (Competitive Solicitation (Bidding) Information – Electric)	The terms of the Long-Term Resource Adequacy Agreement presented in this appendix are generally confidential. Confidential quantitative analysis for scoring and evaluating bids in solicitation	Contract documents and terms of contracts are confidential for three years from the date that the contract states that deliveries are to begin, or until one year following expiration, whichever comes first. Three years after winning bidders selected
Appendix B: Executed Amendment	Item VII.B (Contracts and Power Purchase Agreements between utilities and non-Affiliated Third Parties (except RPS)), VIII.B (Competitive Solicitation (Bidding) Information – Electric).	The terms of the Long-Term Resource Adequacy Agreement presented in this appendix are generally confidential. Confidential quantitative analysis for scoring and evaluating bids in solicitation	Contract documents and terms of contracts are confidential for three years from the date that the contract states that deliveries are to begin, or until one year following expiration, whichever comes first. Three years after winning bidders selected

Appendix A

Key Aspects to the Amendment RAA w/ES Amendment

(Confidential)

Appendix B

Corby Energy Storage, LLC – Corby Storage (LT RAA w/ES) Amendment

(Confidential)

Appendix C

Proposed Protective Order

(Public)

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes	))))	**Advice 7331-E**

[PROPOSED] PROTECTIVE ORDER

1. Scope. This Protective Order shall govern access to and the use in connection with the above-referenced Advice Letter (the "Advice Letter") of Protected Materials, produced by, or on behalf of, any Disclosing Party.

2. Modification. This Protective Order shall remain in effect until it is modified or terminated by the Commission or the Administrative Law Judge Division ("ALJ Division"). The parties acknowledge that the identity of the parties submitting Protected Materials may differ from time to time. In light of this situation, the parties agree that modifications to this Protective Order may become necessary, and they further agree to work cooperatively to devise and implement such modifications in as timely a manner as possible. Each party governed by this Protective Order has the right to seek changes in it as appropriate from the ALJ Division or the Commission.

3. Definitions

A. The term "Protected Material(s)" means (i) trade secret, market sensitive, or other confidential and/or proprietary information as determined by the Disclosing Party in accordance with the provisions of D.06-06-066 and subsequent decisions, General Order 66-Cand 454.5(g), or any other right of confidentiality provided by law, or (ii) any other materials that are made subject to this Protective Order by the ALJ Division, Law and Motion Administrative Law Judge

("Law and Motion ALJ"), Assigned Commissioner, the Commission, or any court or other body having appropriate authority. Protected Materials also includes memoranda, handwritten notes, spreadsheets, computer files and reports, and any other form of information (including information in electronic form) that copies, discloses, or compiles other Protected Materials or from which such materials may be derived (except that any derivative materials must be separately shown to be confidential). Protected Materials do not include: (i) any information or document contained in the public files of the CPUC or any other state or federal agency, or in any state or federal court; or (ii) any information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order or any other protective order.

B. The term "redacted" refers to situations in which Protected Materials in a document, whether the document is in paper or electronic form, have been covered, blocked out, or removed. The term "unredacted" refers to situations in which the Protected Materials in a document, whether in paper or electronic form, have not been covered, blocked out, or removed.

C. The term "Disclosing Party" means a party who initially discloses any specified Protected Materials in connection with the Advice Letter.

D. The term "Market Participant" ("MP") refers to a party that is:

1) A person or entity, or an employee of an entity, that engages in the wholesale purchase, sale or marketing of energy or capacity, or the bidding on or purchasing of power plants, or bidding on utility procurement solicitations, or consulting on such matters, subject to the limitations in 3) below.

2) A trade association or similar organization, or an employee of such organization,

   a) whose primary focus in proceedings at the Commission is to advocate for persons/entities that purchase, sell or market energy or capacity at wholesale; bid on, own, or purchase power plants; or bid on utility procurement solicitations; or

   b) a majority of whose members purchase, sell or market energy or capacity at wholesale; bid on, own, or purchase power plants; or bid on utility procurement solicitations; or

c) formed for the purpose of obtaining market sensitive information; or

d) controlled or primarily funded by a person or entity whose primary purpose is to purchase, sell or market energy or capacity at wholesale; bid on, own, or purchase power plants; or bid on utility procurement solicitations.

3) A person or entity that meets the criteria of 1) above is nonetheless not a market participant for purpose of access to market sensitive data unless the person/entity seeking access to market sensitive information has the potential to materially affect the price paid or received for electricity if in possession of such information. An entity will be considered not to have such potential if:

a) the person or entity's participation in the California electricity market is *de minimis* in nature. In the resource adequacy proceeding (R.05-12-013) it was determined in D.06-06-064 § 3.3.2 that the resource adequacy requirement should be rounded to the nearest megawatt (MW), and load serving entities (LSEs) with local resource adequacy requirements less than 1 MW are not required to make a showing. Therefore, a *de minimis* amount of energy would be less than 1 MW of capacity per year, and/or an equivalent of energy; and/or

b) the person or entity has no ability to dictate the price of electricity it purchases or sells because such price is set by a process over which the person or entity has no control, *i.e.*, where the prices for power put to the grid are completely overseen by the Commission, such as subject to a standard offer contract or tariff price. A person or entity that currently has no ability to dictate the price of electricity it purchases or sells under this section, but that will have such ability within one year because its contract is expiring or other circumstances are changing, does not meet this exception; and/or

c) the person or entity is a cogenerator that consumes all the power it generates in its own industrial and commercial processes, if it can establish a legitimate need for market sensitive information.

E. A Market Participant's Reviewing Representatives are limited to persons designated by the Market Participant who meet the following criteria:

1. Are outside experts, consultants or attorneys;

2. Are not currently engaged, directly or indirectly, in (a) the purchase, sale, or marketing of electrical energy or capacity or natural gas (or the direct supervision of any employee(s) whose duties include such activities), (b) the bidding on or purchasing of

power plants (or the direct supervision of any employee(s) whose duties include such activities), or (c) consulting with or advising others in connection with any activity set forth in subdivisions (a) or (b) above (or the direct supervision of any employee(s) whose duties include such activities or consulting); and

3. Are not an employee of a market participant.

F. Persons or entities that do not meet the definition of market participant are non-market participants ("NMPs"), and may have access to market sensitive information through their designated Reviewing Representatives. An attorney or consultant that simultaneously represents market participant(s) and non-market participant(s) may not have access to market sensitive data. If, on the other hand, simultaneous representation is of market participant and non-market participant clients involved in completely different types of matters, there should be no bar (although there may be ethical implications of such representation that we do not address here). If, for example, an attorney represents a market participant in matters unrelated to procurement, resource adequacy, RPS, or the wholesale purchase, sale or marketing of energy or capacity, or the bidding on or purchasing of power plants, or bidding on utility procurement solicitations, in a forum other than this Commission, and simultaneously represents a non-market participant in cases related to these topics before the Commission, there should be no bar to the attorney's receipt of market sensitive data (pursuant to a non-disclosure agreement and protective order) in the latter matter. In close cases, the balance should militate to bar simultaneous representation because of the risks it poses.

H. All Reviewing Representatives are required to execute a non-disclosure agreement and are bound by the terms of this Protective Order.

<u>4. Designation of Materials</u>. When submitting materials in connection with the Advice Letter containing Protected Materials, a party shall physically mark such documents on each page (or in the case of non-documentary materials such as computer diskettes, on each item) as "PROTECTED MATERIALS SUBJECT TO PROTECTIVE ORDER," or with words of similar import as long as one or more of the terms, "Protected Materials," "Protective Order," or

“General Order No. 66-C” is included in the designation to indicate that the materials in question are protected.

All materials so designated shall be treated as Protected Materials unless and until (a) the designation is withdrawn pursuant to Paragraph 17 hereof, or (b) an ALJ, Commissioner or other Commission representative makes a determination pursuant to Paragraph 4 hereof changing the designation.

All documents containing Protected Materials that are submitted to Commission Staff in connection with the Advice Letter, or filed with the Commission or served, shall be placed in sealed envelopes or otherwise appropriately protected and shall be endorsed to the effect that they are submitted, filed or served under seal pursuant to this Protective Order. Such documents shall be served upon Reviewing Representatives and persons employed by or working on behalf of the state governmental agencies referred to in Paragraph 12 hereof who are eligible and have requested to review such materials. Service upon the persons specified in the foregoing sentence may either be (a) by electronic mail in accordance with the procedures adopted in connection with advice letters, (b) by facsimile, or (c) by overnight mail or messenger service. Whenever service of a document containing Protected Materials is made by overnight mail or messenger service, Commission Staff and/or the ALJ Division, as may be appropriate for purposes of review and disposition of the Advice Letter, shall be served with such document by hand on the date that service is due.

5. Redaction of Documents. Whenever a party submits to Commission Staff, or files, serves or provides in discovery, a document that includes Protected Materials (including but not limited to briefs, testimony, exhibits, and responses to data requests), such party shall also prepare a redacted version of such document. The redacted version shall enable persons familiar with the Advice Letter to determine with reasonable certainty the nature of the data that has been redacted and where the redactions occurred. The redacted version of a document to be submitted or filed shall be served on all persons on the utility’s advice letter service list and on any third

parties as specified by statute or other Commission order, and the redacted version of a discovery document shall be served on all persons entitled thereto.

6. Selection of Reviewing Representatives. Each MP and NMP selecting a Reviewing Representative shall first identify its proposed Reviewing Representative to the Disclosing Party. An attorney or consultant that simultaneously represents market participant(s) and non-market participant(s) may not have access to market sensitive data, subject to the exception in paragraph 3.F. Any designated Reviewing Representative has a duty to disclose to the Disclosing Party any potential conflict that puts him/her in violation of Decision 06-12-030. A resume or curriculum vitae is reasonable disclosure of such potential conflicts, and should be the default evidence provided in most cases.

7. Access to Protected Materials and Use of Protected Materials. Subject to the terms of this Protective Order, Reviewing Representatives shall be entitled to access to Protected Materials. All other parties in this proceeding shall not be granted access to Protected Materials, but shall instead be limited to reviewing redacted versions of documents. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials. Protected Materials obtained by a party in connection with the Advice Letter may also be requested by that party in a subsequent Commission proceeding, subject to the terms of any protective order governing that subsequent proceeding, without constituting a violation of this order.

8. Maintaining Confidentiality of Protected Materials. Each Reviewing Representative shall treat Protected Materials as confidential in accordance with this Protective Order and the Non-Disclosure Certificate executed pursuant to Paragraph 7 and 8 hereof. Protected Materials shall not be used except as necessary in connection with review and disposition of the Advice Letter, and shall not be disclosed in any manner to any person except (i) Reviewing

Representatives who have executed Non-Disclosure Certificates; (ii) Reviewing Representatives' paralegal employees and administrative personnel, such as clerks, secretaries, and word processors, to the extent necessary to assist the Reviewing Representatives, provided that they shall first ensure that such personnel are familiar with the terms of this Protective Order, and have signed a Non-Disclosure Certificate, (iii) persons employed by or working on behalf of the CEC or other state governmental agencies covered by Paragraph 12. Reviewing Representatives shall adopt suitable measures to maintain the confidentiality of Protected Materials they have obtained pursuant to this Protective Order, and shall treat such Protected Materials in the same manner as they treat their own most highly confidential information. Reviewing Representatives shall be liable for any unauthorized disclosure or use by their paralegal employees or administrative staff. In the event any Reviewing Representative is requested or required by applicable laws or regulations, or in the course of administrative or judicial proceedings (in response to oral questions, interrogatories, requests for information or documents, subpoena, civil investigative demand or similar process) to disclose any of Protected Materials, they shall immediately inform the Disclosing Party of the request, and the Disclosing Party may, at its sole discretion and cost, direct any challenge or defense against the disclosure requirement, and the Reviewing Representative shall cooperate in good faith with such party either to oppose the disclosure of the Protected Materials consistent with applicable law, or to obtain confidential treatment of them by the person or entity who wishes to receive them prior to any such disclosure. If there are multiple requests for substantially similar Protected Materials in the same case or proceeding where a Reviewing Representative has been ordered to produce certain specific Protected Materials, the Reviewing Representative may, upon request for substantially similar materials by another person or entity, respond in a manner consistent with that order to those substantially similar requests.

9. Exception for California Independent System Operator (ISO). Notwithstanding any other provision of this Protective Order, with respect to an ISO Reviewing Representative only, participation in the ISO's operation of the ISO-controlled grid and in its administration of the

ISO-administered markets, including, but not limited to, markets for ancillary services, supplemental energy, congestion management, and local area reliability services, shall not be deemed to be a violation of this Protective Order.

10. Non-Disclosure Certificates. A Reviewing Representative shall not inspect, participate in discussions regarding, or otherwise be granted access to, Protected Materials unless and until he or she has first completed and executed a Non-Disclosure Certificate, attached hereto as Appendix A, and delivered the original, signed Non-Disclosure Certificate to the Disclosing Party. The Disclosing Party shall retain the executed Non-Disclosure Certificates pertaining to the Protected Materials it has disclosed and shall promptly provide copies of the Non-Disclosure Certificates to Commission Staff upon request.

11. Return or Destruction of Protected Materials. Protected Materials shall remain available to Reviewing Representatives until the later of the date that disposition of the Advice Letter becomes no longer subject to review, or the date that any other Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Reviewing Representatives shall, within fifteen days of such request, return the Protected Materials (including Notes of Protected Materials) to the Participant that produced them, or shall destroy the materials, except that copies of materials submitted to the Commission in connection with the Advice Letter that contain Protected Materials, and Notes of Protected Material may be retained, if they are maintained in accordance with Paragraph 8. Within such time period each Reviewing Representative, if requested to do so, shall also submit to the Disclosing Party an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 8. To the extent Protected Materials are not returned or destroyed, they shall remain subject to the Protective Order and CPUC General Order No. 66-C. In the event that a Reviewing Representative to whom Protected Material are disclosed ceases to be engaged to provide services in connection with the

Advice Letter, then access to such materials by that person shall be terminated. Even if no longer engaged in conection with the Advice Letter, every such person shall continue to be bound by the provisions of this Protective Order and the Non-Disclosure Certificate.

12. Access and Use by Governmental Entities.

(a) In the event the CPUC receives a request from the CEC for a copy of or access to any party's Protected Materials, the procedure for handling such requests shall be as follows. Not less than five (5) days after delivering written notice to the Disclosing Party of the request, the CPUC shall release such Protected Materials to the CEC upon receipt from the CEC of an Interagency Information Request and Confidentiality Agreement ("Interagency Confidentiality Agreement"). Such Interagency Confidentiality Agreement shall (i) provide that the CEC will treat the requested Protected Materials as confidential in accordance with this Protective Order, (ii) include an explanation of the purpose for the CEC's request, as well as an explanation of how the request relates to furtherance of the CEC's functions, (iii) be signed by a person authorized to bind the CEC contractually, and (iv) expressly state that furnishing of the requested Protected Materials to employees or representatives of the CEC does not, by itself, make such Protected Materials public. In addition, the Interagency Confidentiality Agreement shall include an express acknowledgment of the CPUC's sole authority (subject to judicial review) to make the determination whether the Protected Materials should remain confidential or be disclosed to the public, notwithstanding any provision to the contrary in the statutes or regulations applicable to the CEC.

(b) In the event the CPUC receives a request for a copy of or access to a party's Protected Materials from a state governmental agency other than the CEC that is authorized to enter into a written agreement sufficient to satisfy the requirements for maintaining confidentiality set forth in Government Code Section 6254.5(e), the CPUC may, not less than five (5) days after giving written notice to the Disclosing Party of the request, release such protected material to the requesting governmental agency, upon receiving from the requesting agency an executed Interagency Confidentiality Agreement that contains the same provisions described in Paragraph 10(a) above.

(c) The CEC may use Protected Materials when needed to fulfill its statutory responsibilities or cooperative agreements with the CPUC. Commission confidentiality designations will be maintained by the CEC in making such assessments, and the CEC will not publish any assessment that directly reveals the data or allows the data submitted by an individual load serving entity ("LSE") to be "reverse engineered."

13. Dispute Resolution. All disputes that arise under this Protective Order, including but not limited to alleged violations of this Protective Order and disputes concerning whether materials were properly designated as Protected Materials, shall first attempted to be resolved through meet and confer. If the meet and confer process is unsuccessful, the involved parties may present the dispute for resolution to the ALJ Division.

14 Other Objections to Use or Disclosure. Nothing in this Protective Order shall be construed as limiting the right of a party, the Commission Staff, or a state governmental agency covered by Paragraph 12 from objecting to the use or disclosure of Protected Material on any legal ground, such as relevance or privilege.

15. Remedies. Any violation of this Protective Order shall constitute a violation of an order of the CPUC. Notwithstanding the foregoing, the parties and Commission Staff reserve their rights to pursue any legal or equitable remedies that may be available in the event of an actual or anticipated disclosure of Protected Materials.

16. Withdrawal of Designation. A Disclosing Party may agree at any time to remove the "Protected Materials" designation from any materials of such party if, in its opinion, confidentiality protection is no longer required. In such a case, the Disclosing Party will notify all other parties that the Disclosing Party believes are in possession of such materials of the change of designation.

17. Interpretation. Titles are for convenience only and may not be used to restrict the scope of this Protective Order.

Entered: ___________________________________
Administrative Law Judge

Date: ___________________________________

APPENDIX A TO PROTECTIVE ORDER

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes _______________________________________	))))	**Advice 7331-E**

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Protected Materials is provided to me pursuant to the terms and restrictions of the Protective Order in connection with the above referenced Advice Letter, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by it. I understand that the contents of the Protected Materials, any notes or other memoranda, or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with that Protective Order. I acknowledge that a violation of this certificate constitutes a violation of an order of California Public Utilities Commission.

By: ______________________________
Title:_____________________________
Representing: ______________________
Date: _____________________________

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T

Albion Power Company
Alta Power Group, LLC

Anderson & Poole

Atlas ReFuel BART

BART
Buchalter
Barkovich & Yap, Inc.
Braun Blaising Smith Wynne, P.C.

California Community Choice Association
California Cotton Ginners & Growers Association
California Energy Commission
California Hub for Energy Efficiency
California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine
Cameron-Daniel, P.C.
Casner, Steve
Center for Biological Diversity
Chevron Pipeline and Power
City of Palo Alto
City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Communities Association (WMA)

Davis Wright Tremaine LLP

Day Carter Murphy
Dept of General Services
Douglass & Liddell
Downey Brand LLP
Dish Wireless L.L.C.

East Bay Community Energy

Ellison Schneider & Harris LLP
Electrical Power Systems, Inc.
Fresno
Engineers and Scientists of California

GenOn Energy, Inc.

Green Power Institute

Hanna & Morton LLP

ICF consulting
iCommLaw

International Power Technology

Intertie
Intestate Gas Services, Inc.

Kelly Group

Ken Bohn Consulting
Keyes & Fox LLP

Leviton Manufacturing Co., Inc.
Los Angeles County Integrated

Waste Management Task Force

MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McClintock IP
McKenzie & Associates
Modesto Irrigation District

NOSSAMAN LLP
NRG Solar

OnGrid Solar

Pacific Gas and Electric Company
Peninsula Clean Energy
Pioneer Community Energy

Public Advocates Office

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
Resource Innovations
Rockpoint Gas Storage

San Diego Gas & Electric Company
SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company

Spark Energy

Sun Light & Power
Sunshine Design
Stoel Rives LLP

Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.
TransCanada

Utility Cost Management
Utility Power Solutions

Water and Energy Consulting
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)

Yep Energy

ATTACHMENT 39

Stantec Draft Report on Engineering Assessments

CONFIDENTIAL

Stantec Draft Report on Engineering Assessments

PUBLIC

Pacific Gas & Electric Company

Draft Report on Engineering Assessment for the Uprate of Helms Pumped Storage Plant

Prepared for:
Pacific Gas and Electric

Prepared by:
Stantec Consulting Services, Inc.

September 2023

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Abbreviations and Acronyms

AC	Alternating Current
ABB	Asea Brown Boveri Company
ADC	Amperes Direct Current
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
BIL	Basic Insulation Level
BOP	Balance of Plant
BPVC	Boiler and Pressure Vessel Code
CB	Circuit Breaker
CEATI	Center for Energy Advancement and Technological Innovation
CFD	Computational Fluid Dynamics
cfs	Cubic Feet per Second
DC	Direct Current
DDC	Direct Digital Control
DGA	Dissolved Gas Analysis
DIA	Diameter
DOO	Description of Operations
DTPP	Draft Tube Pressure Pulsations
EL	Elevation
FEA	Finite Element Analysis
FKM	Forschungskuratorium Maschinenbau
FMEA	Failure Mode and Effects Analysis
ft/s	Feet per Second
GE	General Electric Company
GSU	Generator Step-Up Transformer
GVO	Gate Valve Opening
HMI	Human Machine Interface
HP	Horsepower

HV	High Voltage
ID	Inside Diameter
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IFT	Interfacial Tension Test
IPS	Iron Pipe Size
ISO	International Organization for Standardization
KCM	Kilo Circular Mills
KV	Kilovolt
LED	Light Emitting Diode
LV	Low Voltage
MOD	Modification
MR	Multi ratio
MRCT	Multi Ratio Current Transformer
MW	Megawatt
MVA	Megavolt Amperes
NDE	Non-destructive Examination
NEMA	National Electrical Manufacturers Association
NFPA	National Fire Protection Association
OD	Outer Diameter
OEM	Original Equipment Manufacturer
OFWF	Oil Forced Water Forced
OMI	Operations and Maintenance Instructions
ONAN	Oil Natural Air Natural
PG&E	Pacific Gas & Electric Company
PF	Power Factor
PLC	Programmable Logic Controller
PMG	Permanent Magnet Generator
PPT	Power Potential Transformer
psi	Pounds per Square Inch

PSP	Pumped Storage Project
RMS	Root Mean Square
ROI	Region of Interest
RPM	Revolutions per Minute
RSI	Rotor Stator Interaction
RTD	Resistance Temperature Detector
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCFM	Standard Cubic Feet per Minute
SME	Subject Matter Expert
TSV	Turbine Shut-off Valve
UPS	Uninterruptible Power Supply
USACE	U.S. Army Corps of Engineers
UT	Ultrasonic Testing
VAC	Volts – Alternate Current
VDC	Volts – Direct Current
VLA	Vented Lead-Acid
XLPE	Cross Linked Polyethylene

Stantec

1.0 Executive Summary

This Engineering assessment report includes assessments of systems and equipment within the Helms Powerhouse. PG&E has previously performed various engineering assessments that are documented in multiple reports. The main purpose of this report is to provide a single source containing the assessments and help develop a recommended scope of work for continued 40-year operating life and potential upgrade of the units. The report contains high level condition assessments, replacement/refurbishment recommendations and identified risks.

An overall review of existing assessments and analysis, design data, test results, operation and maintenance records as well as independent analysis was performed by Stantec to determine the conditions of the equipment and systems and establish limits of the equipment and systems. The following are the summaries of the results (Table 1-1):

Table 1-1. Equipment Condition and Capacity Summary

	Equipment / System	Condition	Existing Capacity	Uprate Constraint
1.0	**Pump Turbine**			
1.1	Runner and Coupling	Good Condition (Replacement Proposed)	404 MW	455-460 MW
1.2	Discharge Ring	Good / Moderate Condition (Refurbishment and Modification proposed)	≥404 MW	≥460 MW
1.2	Head Cover	Good / Moderate Condition (Refurbishment and Modification proposed)	≥404 MW	≥460 MW
1.3	Pump-turbine shaft and Motor-Generator Lower Shaft	Good / Moderate Condition (Refurbishment and Modification proposed)	≥460 MW	≥460 MW
1.4	Stay Vanes and Spiral Case	Good Condition (Refurbishment proposed)	≥460 MW	≥460 MW
1.5	Wicket gate system and Operating Ring	Good / Moderate Condition (Refurbishment and Modification proposed)	≥404 MW	≥460 MW
1.6	Wicket gate servomotors	Good Condition (Refurbishment proposed)	≥460 MW	≥460 MW
1.7	Turbine Guide Bearing	Moderate Condition (Replacement / Modification Proposed)	≥404 MW	≥460 MW
1.8	Cooling Water System	Good / Moderate Condition (Refurbishment and Modification proposed)	≥404 MW	≥460 MW
1.9	Shaft seal and clean water system	Good / Moderate Condition (Refurbishment or Replacement proposed)	≥404 MW	≥460 MW

	Equipment / System	Condition	Existing Capacity	Uprate Constraint
1.10	Governor	Good / Moderate Condition (Refurbishment and Modification proposed)	≥420 MW	≥460 MW
1.11	Draft Tube	Good Condition (Refurbishment and Modification proposed)	≥404 MW	≥460 MW
2.0	**Motor - Generators**			
2.1	Electromagnetic and Ventilation Design	Moderate Condition (Modification and Replacement Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)
2.2	Stator Windings	Good/Moderate Condition (Replacement Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)
2.3	Stator Core	Poor Condition (Replacement Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)
2.4	Stator Frame	Good/Moderate Condition (Modification or Replacement Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)
2.5	Stator Foundations	Good/Moderate Condition (Refurbishment and Modification Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)
2.6	Rotor Pole Windings	Moderate/Poor Condition (Modification or Replacement Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)
2.7	Damper Windings	Moderate Condition (Replacement Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)
2.8	Rotor Pole Laminations and Endplates	Moderate Condition (Replacement Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)
2.9	Rotor Spider	Moderate Condition (Modification Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)
2.10	Rotor Rim	Moderate Condition (Refurbishment or Modification Proposed)	≥460 MW (PF 0.90)	≥460 MW (PF 0.90)
2.11	Brake and Brake Ring	Poor Condition (Replacement Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)
2.12	Generator Shaft and Couplings	Good / Moderate Condition (Refurbishment and Modification Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)
2.13	Upper Bracket	Poor Condition (Replacement Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)

	Equipment / System	Condition	Existing Capacity	Uprate Constraint
2.14	Combined Thrust and Guide Bracket	Good/Moderate Condition (Refurbishment and Modification Proposed)	≥404 MW (PF 0.90)	≥460 MW (PF 0.90)
2.15	Thrust and Guide Bearings	Good/Moderate Condition (Refurbishment and Modification Proposed)	≥460 MW (PF 0.90)	≥460 MW (PF 0.90)
3.0	Other Major Elements			
3.1	Water Conveyance System	Good Condition (No Replacement/Refurbishment Proposed)	≥ 460 MW	Not Applicable
3.2	Pump Turbine Shut-off Valves	Poor/Moderate Condition (Requires Replacement)	404 MW	≥ 460 MW
3. 3	Draft Tube Gates	Poor/Moderate Condition (Requires Replacement)	404 MW	≥ 460 MW
3.4	Station Switchyard System			
3.4.1	Station Switchyard	Moderate Condition (Replacement proposed)	405 MW	≥ 460 MW
3.4.2	Circuit Breakers	Moderate Condition (Replacement proposed)	1,075 MW	≥ 460 MW
3.4.3	Disconnect Switches	Moderate Condition (Replacement proposed)	1,075 MW	≥ 460 MW
3.4.4	Buses	Moderate Condition (Replacement proposed)	423 MW	≥ 460 MW
3.4.5	High Voltage Cables	Moderate Condition (Replacement proposed)	412 MW	≥ 460 MW
3.4.6	Capacitor Power Transformers and Line Traps	Moderate Condition (Replacement proposed)	405 MW	≥ 460 MW
3.4.7	Lightning Arrestors	Moderate Condition (Additions or Modifications proposed)	460 MW	≥ 460 MW
4.0	Balance of Plant - Electrical			
4.1	Medium and Low Voltage Station Service			
4.1.1	Starting Motor Transformers #11, 12 and 13.	Moderate Condition (Replacement proposed)	404 MW	≥ 460 MW

	Equipment / System	Condition	Existing Capacity	Uprate Constraint
4.1.2	13.8 kV Station Service Bus (Starting Motor Bus)	Moderate Condition (Replacement proposed)	404 MW	≥ 460 MW
4.1.3	13.8 kV Station Service Switchgear	Moderate Condition (Replacement proposed)	404 MW	≥ 460 MW
4.1.4	Station Service Transformers #1, 2, 3 and 4	Moderate (Replacement proposed)	460 MW	≥ 460 MW
4.1.5	480V Station Service Switchgear	Good Condition (Re-use proposed)	460 MW	≥ 460 MW
4.1.6	Load Centers 1 to 10	Good Condition (Further Evaluation proposed)	460 MW	≥ 460 MW
4.1.7	Emergency Diesel Generator	Good Condition (Re-use proposed)	460 MW	≥ 460 MW
4.1.8	125VDC Station Power System	Moderate Condition (Further Evaluation proposed)	460 MW	≥ 460 MW
4.1.9	Uninterruptible Power Supply (UPS)	Good Condition (Re-use proposed)	460 MW	≥ 460 MW
4.1.10	Lighting System	Moderate / Good Condition (Replacement proposed)	460 MW	≥ 460 MW
4.1.11	Protection and Control Systems	Good Condition (Further Evaluation proposed)	460 MW	≥ 460 MW
5.0	Main Bank Transformers	Moderate Condition (Replacement proposed)	404 MW	≥ 460 MW
6.0	Disconnect Switches, Iso-Phase Bus and Exciter Bus			
6.1	High Resistance Neutral Grounding Equipment	Good Condition (Further Evaluation proposed)	≥404 MW	≥ 460 MW
6.2	Exciter			
6.2.1	Power Potential Transformer	Moderate Condition (Replacement proposed)	≥404 MW	≥ 460 MW
6.2.2	Excitation Switchgear	Good Condition (Further Evaluation proposed)	≥404 MW	≥ 460 MW
6.3	Starting Equipment			
6.3.1	Starting Motor	Moderate Condition (Refurbishment proposed)	≥404 MW	≥ 460 MW

	Equipment / System	Condition	Existing Capacity	Uprate Constraint
6.3.2	5kV Starting Bus	Good Condition (Re-use proposed)	≥404 MW	≥ 460 MW
6.3.3	Starting Motor Selector Switches	Good Condition (Re-use proposed)	≥404 MW	≥ 460 MW
6.3.4	Liquid Rheostat	Good Condition (Further Evaluation proposed)	≥460 MW	≥ 460 MW
6.4	Isolated Phase Bus	Good Condition (Replacement proposed)	404 MW	≥ 460 MW
6.5	Phase Reversing Switch	Good Condition (Replacement proposed)	404 MW	≥ 460 MW
6.6	Generator/Motor Circuit Breakers	None Existing (Addition proposed)	NA	≥ 460 MW
7.0	Balance Of Plant - Mechanical			
7.1	Cooling Water System	Moderate Condition (Replacement proposed)	≥404 MW	≥ 460 MW
7.2	Lubricating Oil System	Moderate Condition (Refurbishment proposed)	≥404 MW	≥ 460 MW
7.3	Plant Drainage System	Moderate Condition (Further Evaluation proposed)	≥404 MW	≥ 460 MW
7.4	Unwatering System	Moderate Condition (Further Evaluation proposed)	≥404 MW	≥ 460 MW
7.5	Fire Protection System	Moderate Condition (Replacement proposed)	≥404 MW	≥ 460 MW

2.0 Introduction

Helms Pumped Storage Project (PSP) is located east of Fresno, California, is owned and operated by PG&E and was commissioned in 1984. The plant operates between the upper reservoir, Courtright Reservoir, and the lower reservoir, Wishon Reservoir. The plant has three pump-turbine units rated at 404 megawatts (MW) each, for a total installed capacity of 1,212 MW.

PG&E is seeking to uprate the plant capacity by a target of approximately 150-180 MW (of total generation) by upgrading turbine, generator, transformers, and other auxiliary components to maximize the power output without major modifications to the civil/structural elements of the powerhouse as well as extend the service life for another 40 years. Original Equipment Manufacturer (OEM) and consultant engineering studies have been performed to identify the main scope necessary to achieve the uprate. Based on this preliminary analysis, PG&E plans to, at a minimum, upgrade and refurbish the turbine, rewind the generators, replace the stator cores, improve the rotors, replace the main bank transformers, replace the reverse disconnect switches and upgrade the iso phase and exciter bus.

In order to provide PG&E with a holistic overview of the entire plant with respect to the systems and equipment that will need to be assessed and addressed as part of the uprate and life extension, and to provide comprehensive general recommendations based on past Stantec upgrade experiences with similar PSPs, Stantec has assessed and reviewed equipment outside of the aforementioned major components identified for upgrade. Since these components have not been previously identified for upgrade, and since they are not currently part of the focus of the Phase 1 scope of work, they are being summarized in this report by means of general, high-level recommendations. This mostly affects Balance of Plant (BoP) equipment. Major powertrain equipment that has been identified for upgrade, on the other hand, is being reviewed in detail throughout this report and specific upgrade recommendations are being made.

While conventional hydroelectric powerplants may typically be designed for 50 years, pumped storage plants are typically designed for a 40-year design life. This is in large because Mechanical and Electrical components of a PSP are cycled much more frequently than in a typical conventional hydroelectric plant. The structural components of a PSP are typically designed for the same 100 years of design life that conventional plants are designed for. Since Helms PSP was commissioned in the 1980s, most of the Mechanical and Electrical equipment is, expected to currently be at or near the end of its remaining useful life. Helms PSP would need to undergo a lifecycle extension process over the coming years to achieve the 40-year life extension goal without considering the uprate. Since this would involve major capital projects for equipment refurbishment and replacement, uprate of equipment for an incremental increase in cost above the life extension cost, to generate additional energy, would potentially be beneficial.

This engineering assessment report summarizes the condition of the current equipment installed at Helms PSP and its uprate potential. To perform the assessment, Stantec relied on available information such as previously completed component uprate studies, overall plant uprate studies, O&M records, design data, drawings, and operational history of the plant as well as independent analysis by Stantec. On-site condition assessment of any equipment was not performed in this phase and Stantec did not conduct any site visits to support this assessment. After PG&E decides on the option for the uprate of

Helms PSP, additional analysis work and on-site condition assessment will be necessary depending on the selected option for the uprate. These requirements are outlined in this document as well as in Stantec's Gap Analysis Memorandum. Identified gaps will be addressed in the next phase of this project (Phase 2) and will not impact the decision points for selecting the preferred option for the project.

The individual power train components and other equipment and systems assessed in this report are varied and complex, especially and specifically the significant differences in the types and nature of the critical components in the pump-turbine and generator-motor. Additionally, the type, nature, and level of detail of information available for assessment of specific components, equipment, and systems varied considerably. Rather than present this assessment in a "one size fits all" approach, each section was written to be appropriate and fit-for-purpose for the particular equipment and system. Subject Matter Experts (SME) in their respective fields have reviewed and assessed individual components of the powertrain equipment as appropriate to each item and presented their assessments on that basis. Consequently, sections throughout this report may differ in detailed format, type of information presented, and how conclusions and recommendations are drawn.

3.0 Engineering Assessment

The Engineering Assessment scope focuses on the pump-generating units' power train equipment and appurtenant equipment and systems; other major items are also addressed briefly. For each major component and system, this assessment includes the following:

1. Condition assessment and remaining life;
2. Uprate limits, potential, and future design considerations;
3. Equipment capital replacement cost and upgrade cost (covered in Stantec's Alternatives Analysis Report).

General comments on each of the above scope elements are provided below.

Condition assessment and remaining life. For this Phase 1 deliverable, the condition assessment relied on generally available information including previous inspections and reports, maintenance history, and anecdotal information from project staff. No dewatered or other inspections of major components or equipment were performed; if necessary, these inspections will be performed in the next phase. With respect to estimated remaining life, this report includes qualitative assessments based on current assessed condition and trends in condition, and Stantec and general industry experience on other pumped storage projects. For example, CEATI provides guidelines on typical service life for much of the equipment and systems at Helms, which have been used herein where appropriate. Detailed analytical assessments, such as remaining fatigue life, will be performed in the next phase on specific components based on the option selected for the project.

Uprate limits, potential, and future design considerations. Previous studies, and PG&E's goals proposed 463 MW as the maximum uprated pump-turbine capacity. For this Phase 1 deliverable, uprate limits or potentials were developed based on industry experience, electrical ratings for electrical components/equipment, and or simple hand calculations where appropriate. Detailed analytical analyses such as Finite Element Analyses (FEA) or fatigue analyses to establish more precise upper limits will be performed as necessary in the next phase. At this point, unless indicated otherwise in specific subsections below, the major components uprate limits are based on the simplified assessments and may be further optimized in Phase 2 of the project. In some cases, this would require some leeway above the original design stress limits and will be discussed with PG&E.

3.1 PUMP-TURBINE

The Helms powerhouse contains three identical high head, reversible Francis type pump-turbines with a rotational speed of 360 rpm. They were designed and manufactured in Japan by Hitachi and were first placed in operation in June 1984. Their original nameplate rating is 480,000 HP or 357.93 MW at a rated head of 1,625 ft, and they have been operated up to approximately 404 MWs. In pump mode, the unit is rated for a capacity of 2,400 cfs at a total dynamic head of 1,500 ft.

The reservoirs it operates on are Courtright Lake (Upper Reservoir), with water levels ranging between 8,184 ft to 8,020 ft above sea level, and Lake Wishon (Lower Reservoir) which water levels vary between

6,550 ft to 6,440 ft above sea level, resulting in a range of gross operating heads between 1,744 ft and 1,470 ft.

The spiral case is a welded plate steel design, and the draft tube is a steel lined elbow design.

The pump-turbine itself is nearing the typical age for intervention with options for a choice of refurbishment or replacement / upgrade. All pump-turbine components will need analyses, assessments, and alternative(s) for future action developed.

Summarized in Table 3-1 below is a table of predesign activities which should be performed as part of preparing for a Pump-Turbine overhaul or replacement.

Table 3-1. Summary of Pump-Turbine Recommended Pre – Design- Work Scope Items Recommended

Pump-Turbine	Scope of Work
Wicket Gate Servo Motors	Perform a preliminary condition assessment on the servos to estimate the mean time between major refurbishments using the last refurbishment time as a basis. Assess the present servo motor leakages across the cylinder seals, and out of the piston rod / shaft packing. Assess the pins for migration and alignment and rod surface condition. Document present squeeze and relaxation distance for use with project. Use this info for planning of the outage.
Head Cover Runner Band Drain Valves	Assess the valves, their actuators, and verify their operation with the auto control system. With the information gathered reach out to vendors to assess lead times for replacement valve body and custom trim. Assess the piping also to determine if piping replacement is required during the outage to achieve new service life criteria.
Turbine and Lower Generator Shafts	Perform an FEA on the shaft system (pump-turbine and motor-generator) as part of the pre outage assessment to determine reusability for refurbishment or uprate.
Head Cover	Assess head cover condition for cracking or broken welds. Perform an FEA and fatigue analysis of head cover to determine suitability for reuse given expected load cycling. Should the OEM propose a turbine runner with a different number of blades it would be prudent to conduct a modal analysis to assess the head cover for possible resonance.

3.1.1 Assessment of Existing Condition

Presently the pump-turbine and runners are all in continuous operation with no major issues reported other than a crack on one of the runner blades, and a small indication on another, discovered during a recent inspection. The blade cracking, if not done already should be reviewed in terms of fatigue cracking and fracture mechanics. Employment of an Ultrasonic or phased array inspection program is recommended if not done already to monitor the crack sites after repair so to ensure that they do not reinitialize or progress to the point where a blade failure may occur. Stantec can offer additional information on the runner blades. Sometimes a load restriction is put in place to prevent further crack growth via overspeed conditions, this is usually done in conjunction with limiting the machines start-stop cycling also to limit growth. Because Helms is a pump storage plant, it is exposed to full loading in pump mode, and is often cycled many times more than a traditional hydro plant. As such, investigation into the mechanics of the cracks and a periodic inspection with NDE is highly recommended until the runner is replaced.

3.1.2 Uprate Potential and Hydraulic Capacity

Simple replacement of the existing pump-turbine runner by itself (with no precise uprate specified) would result in a minor power uprate just through increased efficiencies, given the advances in hydraulic and CFD design and model testing since the original construction. Those advances have reduced hydraulic losses and cavitation and enabled hydraulically improved blade profile shapes to be achieved over the past 40 years. Additional turbine uprate amounts can be achieved by increasing the runner's capacity to pass additional flow.

3.1.2.1 Hitachi Analyses

Hitachi prepared a preliminary analysis of potential turbine uprates, including what Hitachi designated as Plan A and Plan B modifications, each with varying levels of runner outlet and draft tube modifications. See Figure 3-1 below for specific details of the modifications includes in each Plan.

[redacted]

Figure 3-1. Hitachi Proposed Modifications for Plan A and Plan B

Note in the above figure that the Plan B modification would also enlarge the runner turbine outlet as shown in Plan A. The existing runner throat diameter is 2,486.9 mm; Plan A would enlarge that diameter to 2,620 mm, Plan B would enlarge it slightly further, to 2,630 mm.

Hitachi's proposed Plans A and B would increase the turbine output at maximum net head by approximately [redacted] and [redacted] respectively without replacement of any of the existing wicket gate operating mechanism and servomotors, but the turbine maximum output at minimum net head would only increase approximately [redacted] and [redacted] respectively. Their report and follow-up correspondence indicates that the risk of Rotor Stator Interaction (RSI), cavitation pitting, and increased vibration for these two Plans is low.

Plan A would require relatively little intervention to the existing unit and civil works, with only the upper portion (the first approximately 1.5 m) of the upper draft tube and discharge ring requiring modifications. Hitachi has communicated they have done similar Plan A type modifications for other plants, which is worth noting for requesting references. Plan B modifications would involve the enlarged runner throat as well as substantial draft tube modifications which would involve heavy civil work and replacement of the entire draft tube.

The chart below (Figure 3-2) shows their Plan A (green solid line) and Plan B (red solid line) approach with respect to current generation 'limits' (the dashed green line), using the present stay vane geometry and wicket gates and without exceeding the existing maximum servomotor stroke. The limits indicated below were selected by Hitachi, based on their design and experience, to avoid the risk of excessively rough operation due to draft tube whirl and/or overload surge.

[redacted]

Figure 3-2. Operating Range and Efficiency Curves (Plan A & B)

3.1.2.2 *Maximum Uprate Potential*

<u>Head Loss and Other Hydraulic Effects</u>

Hitachi uprate studies performed thus far have suggested a maximum uprate potential of 463 MW (turbine output) at a maximum net head of 1,744', with the Plan B approach described above. This value, however, corresponds to the maximum available gross head on the pump-turbines (i.e., Courtright Lake at maximum elevation of 8,184' and Lake Wishon at minimum elevation of 6,440') - and does not consider head losses within the water conduit.

Stantec alerted Hitachi to this Net Head discrepancy which, when addressed, would result in a slightly lower maximum than what Hitachi indicated. However, their figures could be seen as a possible upper limit for a power upgrade, without major equipment or civil work modifications (while likely avoiding surge/pressure pulsation issues and cavitation erosion on the blades).

Based on efficiency testing performed in 1989, head losses during both single-unit and three-unit operation were determined. An excerpt of Unit 1 data is provided below as an example (Figure 3-3):

[redacted]

Figure 3-3. Power, Flow & Head Loss at Various Wicket gate Opening

Using similar tables for Units 1 through 3, as well as three-unit operation data, the following head loss coefficients were developed, where the head loss in feet may be calculated by the equation $H_L = \mathbf{k} * Q^2$, with the flow "Q" in cfs (Table 3-2):

Table 3-2. Head Loss Co-efficient for Individual and 3-Unit Operation

	Unit 1	Unit 2	Unit 3	3 Unit
Head Loss Coefficient, K	2.056 E-6	2.077 E-6	2.145 E-6	4.965E-7

For single unit operation, the maximum head loss observed was approximately 26-27', for a flow of approximately 3,500 cfs. For three-unit operation, the maximum head loss observed was approximately 58' for a total flow of 10,253 cfs.

In consideration of the head loss coefficient, the maximum turbine output achievable with a single unit in operation seems to converge on approximately 610,000 HP (454 MW), given the model test data and maximum prototype wicket gate opening/flows as suggested by Hitachi to avoid overload surge operation. Similarly, when considering head losses during three-unit operation, maximum turbine output seems to converge on about 595,000 HP (444 MW).

However, as noted in the Hitachi Phase 3 report, model/prototype performance curves were developed at high "sigma"; i.e., testing the model at higher pump-turbine runner submergence relative to lower reservoir levels than is possible in actual operation. This provides results **without** consideration of the influence of potential for cavitation at the actual operating lower reservoir levels relative to the pump-turbine runner elevation. This is a common approach – though it is typical to additionally perform model testing at plant sigma (actual lower reservoir levels relative to runner elevation) so that actual limits in operation can be established. It is noted in the Hitachi report that operation at plant sigma would lead to cavitation at higher outputs, as well as a reduction in turbine efficiency as compared to that presented in the model. However, it is expected that the increase in runner throat diameter for Plan A and Plan B could alleviate some cavitation effects as throat velocity decreases. In summary, additional model testing would be required to firmly establish actual allowable maximum outputs. Further, it should be noted that the maximum outputs shown above are only achievable at the occurrence of maximum upper reservoir and minimum lower reservoir.

Oftentimes, what is more significant to Owners is the maximum output at minimum net head, or turbine 'firm' output under all operating conditions. Looking at the Hitachi Phase 3 study, outputs at minimum net head are not substantially increased with their proposed Plan A or Plan B modifications (Table 3-3).

Table 3-3. Potential Generating Capacity at Various Head Levels

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			

It was confirmed with Hitachi that studies have not yet examined the potential for increase in servomotor stroke, as the maximum flow at these minimum heads has not really increased (1.5% flow increase in the plan B option with major draft tube work).

Following correspondence with Hitachi, it was understood that studies have not yet looked to increase wicket gate opening beyond the maximum physical servomotor stroke, because it is expected the runner would enter a zone of hydraulic instability referred to as a bell-shaped whirl, or full load torch, prior to the existing maximum servomotor stroke. Uprate limits presented thus far have been set to avoid this full load torch, which in addition to the rotational component, has a vertical surge type procession in the draft tube which can cause high draft tube pressure pulsations, power swings, and standing waves in the water passage – as well as providing a source for potential excitation of other unit component natural frequencies.

Beyond the full load torch condition, another important hydraulic interaction that must be avoided in any uprate is the appearance of excessive rotor-stator-interaction, or RSI. This term refers to the interaction between the rotational (runner) and stationary (wicket gates, distributor) components of the pump-turbine. Evidence of this phenomenon is always present; however, the effect increases in intensity as wicket gate openings are increased, effectively as the trailing edge of the wicket gates are moved closer to the runner blades. This manifests in high frequency vibrations felt by the runner, wicket gates, and distributor components, potentially leading to high cycle – low stress fatigue issues. Hitachi expressed that they would not expect any RSI issues with the present uprates proposed by Plans A and B. Hitachi provided distances between the wicket gates and runner blades for the existing maximum stroke and Plan A/B maximum stroke, as per Table 3-4 below.

Table 3-4. Distance between wicket gates and runner blades

[redacted]		[redacted]
[redacted]		

Because the stroke has not increased, the minimum space between the runner blades and wicket gate tails has not decreased (i.e., ~180 mm existing and Plan B uprate). Stantec compared this with other pump-turbines, and feels this is comparable with, or more conservative than machines without known RSI issues, as listed in Table 3-5 below (with exception of the [redacted] uprate). This will remain an important topic of study for any new hydraulic design, noting that, as RSI has become more prevalent, designers have been able to incorporate features to lessen its effects.

Table 3-5. Comparison of Helms with Other similar pumping/generating plants

	Number Blades	Number Wicket Gates	RPM	Max Head (feet (meters))	Turbine Rated Power (MW)	Runner Blade Leading Edge CL Diameter (Dr) (inches)	Min. Gap Between Runner Blade & Wicket Gate (Dg) (inches)	Ratio Dg/Dr
Helms (Existing / Plan B Uprate)	6	20	360	1744 (531.6)	379	201.98	7.09	0.035
[redacted]	6	20	225	690 (210	263	[redacted]	[redacted]	[redacted]
[redacted]	7	20	225	690 (210)	352	[redacted]	[redacted]	[redacted]
[redacted]	7	20	225	766 (233.5)	298	[redacted]	[redacted]	[redacted]
[redacted]	7	20	257	1260 (384)	350	[redacted]	[redacted]	[redacted]
[redacted]	9	20	300	1040 (317)	392	[redacted]	[redacted]	[redacted]
[redacted]	8	20	300	1040 (317)	423	[redacted]	[redacted]	[redacted]
[redacted]	7	20	180	420 (128)	134	[redacted]	[redacted]	[redacted]
[redacted]	9	24	500	1793.3 (546.6)	300	[redacted]	[redacted]	[redacted]
[redacted]	7	24	150	351.05 (107)	171	[redacted]	[redacted]	[redacted]
[redacted]	7	20	257.14	1150 (350.5)	250	[redacted]	[redacted]	[redacted]
[redacted]	7	20	400	1263.1 (385)	291	[redacted]	[redacted]	[redacted]

Further, as noted above, the Hitachi studies have thus far considered a constrained approach to the uprate, replacing only the runner and modifying the draft tube. Even the Plan A/Plan B runner hydraulic design is expected to maintain very similar turbine performance and the current minimum operating operation limits, as the runner turbine inlet profile would undergo minimal changes.

This was demonstrated by Hitachi using model test data showing low pressure pulsation values in the deep part load regions. At a high level, Stantec might typically consider a 'rough zone' where draft tube pressure pulsations (DTPP) exceed 3% of the net head, though we have also seen manufacturer criteria up to 5% of net head, or alternative rough zone criteria suggested by literature as less than the square root of the rated head (in meters).

The charts in Figure 3-4 below demonstrate DTPP less than these criteria at low loads, and if shaft/bearing housing vibration and runout is not excessive in this zone, it should be acceptable for operation.

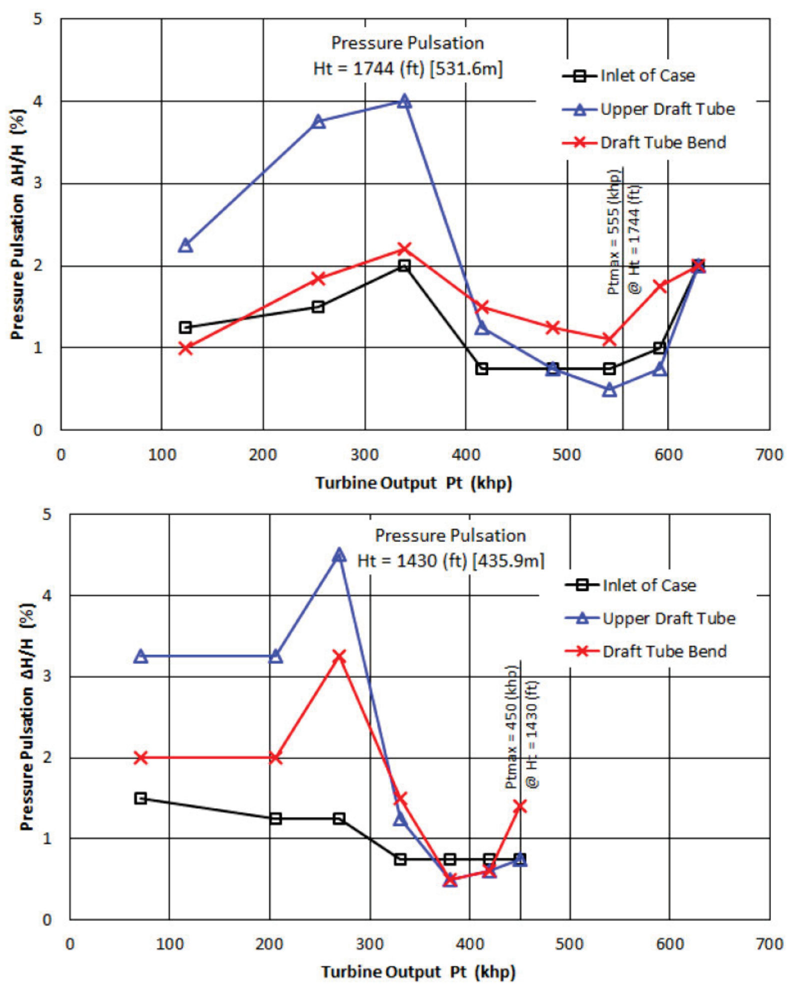


Figure 3-4. Draft Tube Pressure Pulsations

We understand that maintaining the present unit operational envelope with the ability to generate as low as 83 MW is an important request of PG&E, which gives the plant additional flexibility on the grid. Considering a design outside of the constraints laid out by Hitachi may provide a larger uprated capacity but may perhaps result in a change to the unit's rough zone, and as such alter the lower limit of power output, resulting in less of an operating envelope on the low power side.

Other Potential Modifications

In addition to a new runner, pump-turbine modernization efforts might typically include some or any of the following: replacement wicket gates, runner seal replacement, stay vane extensions/modifications, increased wicket gate servomotor stroke, and discharge ring modification.

During preliminary hydraulic design efforts required to prepare a proposal level design and corresponding performance guarantees, pump-turbine designers will evaluate in CFD the distributor cascade of the stay vane, wicket gate, and runner blade. New wicket gates incorporating modern materials and design features might allow for a more slender and efficient design. A change of wicket gates and potentially increased wicket gate angle would likely also best be suited with stay vane reprofiling or extension, to better guide flow into the wicket gates. Though this results in more efficient operation, stay vane modification may require substantial outage time and can be expensive – so the efficiency benefit will need to be evaluated.

This 'unconstrained' approach was discussed with Hitachi, and whether the maximum possible uprate could be increased beyond Plans A and B with a new runner, wicket gates, and minimal changes to embedded parts. While it is understood this has been outside the scope of Hitachi past analyses, it would be possible to increase servomotor stroke to increase the maximum wicket gate opening and/or modifying the hydraulic design of the new runner – pushing the best efficiency point to a higher flow/output – which would help to avoid the full load torch seen at high flows with the existing runner design. However, optimizing runner design for higher outputs would almost certainly push up the minimum output for continuous operation.

Waterway Velocities

When evaluating maximum uprate capacity, the previous Black and Veatch uprate report identified maximum allowable water velocities as 100 feet per second (ft/s) in the steel lined tunnel sections and 30 ft/s in the concrete lined tunnel sections. Stantec is not aware of pumped-storage (or hydro) facilities with velocities up to those mentioned.

Stantec consulted various literature and have not found a 'hard and fast' rule for velocities within the conveyance system, but those referenced suggest velocity limits may be highly dependent on water cleanliness and amount of suspended solids in the water that could otherwise scour the concrete. We understand the water at Helms is very clean and that there has been no sign of concrete damage attributable to water erosion.

In the absence of a clear limit dictated by literature, Stantec performed a survey of waterway velocities for Helms as well as other facilities with more recent pump-turbine upgrades.

Figure 3-5 and Table 3-6 indicate the water velocities at various points within the water passage, for the maximum flows suggested by the existing condition, as well as the 'Plan A' and 'Plan B' uprates from past Hitachi studies. See Figure 3-7 for comparison of the water passage velocities at Helms to other similar pump-generating plants.

[redacted]

Figure 3-5. Helms Water Conveyance System

Table 3-6. Velocities in the existing Water Conveyance System

	Existing	Plan A – Hitachi	Plan B – Hitachi
Max Flow per Unit (cfs):	3144	3454	3510
	Velocity (ft/s)		
27 ft DIA Concrete Lined Tunnels	**16.47**	**18.10**	**18.39**
22 ft DIA Concrete Lined Tunnels	**16.54**	**18.17**	**18.47**
[redacted]			
11.5 ft DIA Steel Lined Penstock	**30.27**	**33.25**	**33.79**
10.5 ft DIA Steel Lined Penstock	**36.31**	**39.89**	**40.54**
7.875 ft DIA Inlet Valve	**64.55**	**70.91**	**72.06**
7.875 ft DIA Spiral Case Inlet	**64.57**	**70.93**	**72.08**
15.5 ft DIA Draft Tube Tunnel	**16.66**	**18.30**	**18.60**
27 ft DIA Tailrace Tunnel	**16.47**	**18.10**	**18.39**

Table 3-7. Water Passage Velocities comparison with Helms

Project	Helms					
	Existing	"Plan B" Uprate	[redacted]	[redacted]	[redacted]	[redacted]
Number of Units	3	3	[redacted]	[redacted]	[redacted]	[redacted]
Max Discharge per Unit (cfs)	3144	3510	[redacted]	[redacted]	[redacted]	[redacted]
Upper Tunnel Velocity (ft/s)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Intermediate Tunnel Velocity (ft/s)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Project	Helms					
	Existing	"Plan B" Uprate	[redacted]	[redacted]	[redacted]	[redacted]
Concrete Penstock Velocity (ft/s)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Steel Penstock Velocity (ft/s)	30.27	33.79	[redacted]	[redacted]	[redacted]	[redacted]
Inlet Valve Velocity (ft/s)	64.55	72.06	[redacted]	[redacted]	[redacted]	[redacted]
Spiral Case Entrance Velocity (ft/s)	64.57	72.08	[redacted]	[redacted]	[redacted]	[redacted]
Draft Tube Tunnel Velocity (ft/s)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tailrace Velocity (ft/s)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
*Steel Lined						
[redacted]						

Based on the above, it appears the maximum uprate identified by Hitachi results in velocities consistent with (or even less in concrete sections) some more recent pump-turbine upgrades. We are not aware of pump-turbine units with velocities near 100 ft/s in steel lined sections. It should be noted that hydraulic issues were encountered at both [redacted] upon their initial uprate and significant engineering and pump-turbine modifications / replacements were ultimately required to restore the units to acceptable operations. While an uprate consistent with Hitachi's "Plan B" might be consistent with what other plants have executed, those plants have required substantial 'lessons learned' type modifications before they achieved long-term reliable operation, so any proposed uprate design will need to be evaluated carefully and thoroughly with CFD and model testing – and it would not be encouraged to increase flows significantly beyond what has been studied thus far.

Summary

In consideration of the above, we consider the Hitachi Plan A/B uprates to be representative of a careful, conservative approach to the maximum uprate that would be possible with no or minimal sacrifice to the lower operating range. Other pump-turbine modifications (i.e., redesigned wicket gates, stay vane modifications, increased stroke) might also be considered to achieve maximum benefits, and would be included and verified in CFD and model testing.

An 'unconstrained' approach with increased wicket gate stroke could allow a higher firm turbine capacity – but would require the turbine best efficiency point moved to higher flows and theoretically sacrificing low load operation and careful engineering to not introduce new damaging hydraulic phenomena like overload surge and RSI.

However, from our survey of waterway velocities, we note the waterway velocities associated with the Helms uprate are consistent with, or already slightly above, some recent substantial uprates at other pump-storage facilities of similar vintage – which required substantial engineering efforts to correct. Maximum wicket gate angle (opening) for the Plan A/B uprate at Helms (29 degrees), is also consistent with, or already greater than the maximum wicket gate angles of similar vintage Hitachi units post uprate at [redacted] (26.5 degrees after reduction due to RSI) and [redacted] (27 degrees).

In consideration of the above, we recommend maintaining the conservative limit from Hitachi and target an uprate capacity of approximately 455 - 460 MW as hydraulic phenomena such as RSI and draft tube whirl (the overpower "torch" type, not the partial load type) is not advised. Such issues have introduced themselves during previous pump-turbine uprates and have required substantial engineering, modifications, and even runner replacements to correct.

Model testing will ultimately provide guarantees for prototype pump-turbine performance, and in a competitive scenario, it will be important to a) set boundaries for permissible pump-turbine modification and b) define a program of selection criteria that accurately capture the benefits of competing hydraulic designs for a quantitative comparison. A supplier may ultimately suggest outputs above 460 MW, but such a design may not best benefit PG&E given the operational scheme. As such, besides max capacity, evaluation criteria typically include weighted average efficiency (with relative weighting on expected operation points), guaranteed operating range and extent of rough zone at different head values, as well as other operational criteria like pressure pulsation, vibration, and cavitation.

3.1.3 Pump-Turbine Runner and Coupling

Estimate of Current Equipment Condition:	Good Condition (Replacement Proposed)
Existing Capacity:	404 MW
Uprate Constraint:	455-460 MW

Runner

The existing pump-turbine runner is composed of 13-5 Chromium Nickel alloy stainless steel castings. From discussion with plant operations, we understand cavitation of the existing runner is not considered to be excessive. Cavitation repairs are typically done on the order of every 5 years, taking approximately 10 shifts to perform.

The first time a crack was observed on the runner was approximately a year ago, near the blade leading edge. A small indication was found on another unit's runner. Weld repairs were performed in both instances.

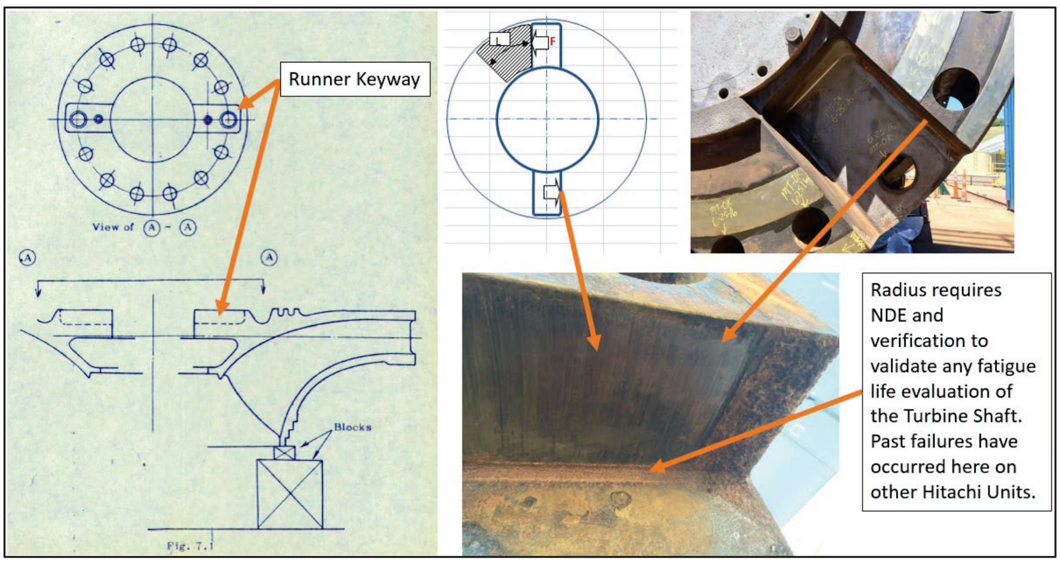
The Helms turbine runner is nearing the typical statistical end of service life criteria of around 40 years of service. A fatigue analysis could be done to determine a more precise anticipated service life, however already one runner has developed cracking at the turbine blade inlets and will now realistically need to monitored going forward until replaced with an NDE program.

The runner with the blade cracking should be considered in poor condition with either operational intervention likely being required for the remainder of its service life until. A detailed FEA and crack propagation study (FEA with fracture mechanics regarding start stop stresses and overspeed stresses) is one option to help assess the unit's risk of failure. Periodic NDE inspections on the repairs in combination with a fracture mechanics study might give further confidence to operations in deciding what load and start stop limitations may be required for the machine until the runner can be replaced but is not a guarantee that the unit will not fail prior to then.

Turbine Runner to Main Shaft Coupling and Torque Keys

The condition of the main shafts torque keyways is not known currently. The Helms units employ a large double torque key system which is a typical Hitachi design. This design has been successful on many machines, however on some there has been cracking detected on the main shaft at the stress riser of the keyway resulting in cracking. Engineering inspection and NDE of the stress riser, as well as measurement to verify its radius is advised as part of any uprate or refurbishment.

In addition to this the gap between the shaft, key, and main runner will need to be measured as part of any assessment made for refurbishments or unit uprates. The keys and keyways of the runner and shaft are precision machined, and dimensional verifications will need to be made to ensure assumptions for future remaining life of this junction are accurate. The key design for an uprate will require this if the shaft is to be used again.



Note: There is a similar Hitachi Keyway and stress riser location shown on the right-hand side at a different pump storage plant.

Figure 3-6. Helms Turbine Runner to Main Shaft Keyway Diagram

Summary

The Helms turbine runner is nearing the typical statistical end of anticipated service (~40 years). A fatigue analysis could be done to determine a more precise anticipated service life, however already one runner has developed cracking at the turbine blade inlets and will now realistically need to monitored going forward with an NDE program until replaced.

The runner with the blade cracking should be considered in poor condition, with additional future intervention possibly being required for the remainder of its service life. A detailed FEA and crack propagation study (FEA with fracture mechanics considering start-stop stresses and overspeed stresses) is one option to help assess the unit's risk of failure. Periodic NDE inspections on the repairs in combination with a fracture mechanics study might give further confidence to operations in deciding what load and start-stop limitations may be required for the machine until the runner can be replaced but is not a guarantee that the unit will not fail prior to then.

Other Hitachi machines of similar design and vintage have experienced issues with shaft cracking, coupling alignment issues, such as fretting wear, and runner band and stationary seal wear/rubbing. An intrusive condition assessment of the runner and its interfaces will help justify a replacement or overhaul/refurbishment project with possibilities for upgrades to the pump-turbine runner and its stationary to rotating interfaces being likely with any new modern OEM design (e.g., new materials which resist galling and wear from pump start operations). Until then, the condition of the other pump-turbine runners and their interfaces should be viewed as moderate, meaning that both the runner and the seals are approaching the limits of their service life, with typical major overhaul scope being needed in the next number of years to ensure future generation reliability and equipment safety.

3.1.4 Discharge Ring

Estimate of Current Equipment Condition:	Good/Moderate Condition (Refurbishment and Modification Proposed)
Existing Capacity:	≥ 404 MW
Uprate Constraint:	≥ 460 MW

The present Hitachi runner turbine outlet diameter is 2,486.6 mm according to the Hitachi runner drawing 10P-057-630. Note this is not a verified As-Found or As-Built dimension; the actual present diameter will however be very close to this, within the unit's assembly and machining tolerances for the turbine runner and stationary band seal interface.

Hitachi has proposed a runner diameter of [redacted] for the maximum 'Plan B' uprate condition, and it is possible, depending on the chosen OEM design, that an uprate will require replacement or modification of the existing discharge ring to accommodate a larger runner throat diameter.

The discharge ring is a plate steel fabrication, with a short, approximately 5" band of stainless steel (integral with the lower wearing ring) extending below the runner and forming part of the hydraulic water passage. Because of the age of the machine, it is likely that the discharge ring itself has received some damage caused by cavitation erosion along the surface, perhaps with damage having occurred around the equalizing line pipe interface, and at the elbow or transition of the discharge ring itself (Figure 3-7).

[redacted]

Figure 3-7. Discharge Ring, Lower Runner Band Seal, Lower Runner Band, and Bottom Ring Interface Assembly Drawing

It is also possible that the interfacing surface of the discharge ring to the lower runner band seal has suffered from cavitation erosion and may require repairs during any future refurbishment or unit uprate. See photo below (Figure 3-8) from a much lower head plant with similar Hitachi design.

Note: Approximately 40-year-old, medium head, 384 MW Pump Storage Francis pump/turbine Discharge Ring (Hitachi, not Helms)

Figure 3-8. Discharge Ring with Removed Lower Runner Band

<u>Lower Runner Band Seal and Cooling Water Flow Supply</u>

The stationary lower runner band seal receives cooling water flow which is vital for heat dissipation at the lower runner band when the machine is spinning in air. The annulus, which is a machined slot in the discharge ring has a very thin depth and is subject to clogging. During the refurbishment, if the original discharge ring and diameters are kept then it would be prudent to restore the annulus to an as new condition. The piping and hardware that receives the embedded cooling water supply pipe must be inspected and if necessary special weld repairs may be needed to ensure no leakage is permitted.

There is a chance that these pipes are broken near the welds, either by cracking or by cavitation erosion. Any new turbine design will need to consider the volumetric water flow rate for the supply, and consider the impact forces of start-up and shutdown on the discharge ring and piping (see Figure 3-9 below).

[redacted]

Figure 3-9. Cooling Water Flow to Runner Seal

Due to the age of the Helms Units and their high head there is also likely cavitation erosion on the cooling water supply outlet ports in both the pump and generate directions downwards axially at an angle. This erosion has the potential to continue to progress towards the discharge ring itself.

Condition Assessment

The maintenance history and past studies provided by PG&E has not indicate any significant issues with the discharge ring. Though the present physical condition has not yet been evaluated by Stantec, it is expected the discharge ring can be reused, likely with some typical overhaul work required to address wear on the discharge ring liner due to corrosion / cavitation.

Uprate Limits

A discharge ring modification (or replacement) to a larger throat diameter is likely recommended to achieve the maximum uprate – though final proposed hydraulic designs from competing OEMs will provide further insight.

3.1.5 Headcover

Estimate of Current Equipment Condition:	Good/Moderate Condition (Refurbishment and Modification Proposed)
Existing Capacity:	≥ 404 MW
Uprate Constraint:	≥ 460 MW

The head cover for Helms is divided into 4 quadrants or main segments which utilize large precision machined radial flanges with 22 radial studs, and 6 positioning alignment dowels per flange, for setting the radial flange position. The head cover's water passage surface has a pocketed inner head cover labyrinth seal, a facing plate and a one stage inner seal immediately prior to the shaft seal's annulus area. These seals are ultimately considered consumable in that they have limited lifespans and eventually will require refurbishment or replacement. They are precision machined inserts and have very tight assembly gap tolerances. An assessment will be required during disassembly to determine what repairs, or modifications is required if any.

The headcover will also need to be assessed for its operating ring ledge wear, wicket gate stem alignment and bore condition for the wicket gate bushings, and most importantly the condition of the head cover to stay ring flange condition. Additional inspections required will include the shaft seal to headcover flange interface, the structural gusseting, and all fabrication welds which are exposed. Hardware is typically NDE inspected to determine if there are any design issues and replaced regardless with new hardware over 2 to 3 inches in diameter.

To determine the condition of the head cover for extended service, or re-use for another 30 to 40 years, an intrusive engineering inspection will need to be performed, including NDE magnetic particle and ultrasonic testing. This will need to be done to ensure the integrity of its welds and plates as the head cover is essentially a pressure boundary. Usually, intrusive inspection is only carried out during the time of an overhaul or major unit disassembly.

In advance of the outage, a fatigue analysis will be required to verify suitability for extended use. We are familiar with similar vintage pump-turbines where fatigue analysis has indicated the headcovers are not suitable for a 30-40-year life extension given ASME BPVC design codes and conservative future projections for unit start-stop cycles. Due to the large component size, numerous sections, and fabrication, a replacement headcover lead time is very likely over a year. For that reason, it will be important that a fatigue analysis be included in the initial engineering studies to make sure it does not come onto critical path, should a new headcover be required.

Prior to reuse, the headcover will need a full NDE of its critical welds. Often an NDE schedule of all major parts and critical inspection zones, or guidance can help inform planning for resources and serve quality control.

3.1.5.1 *Stay Ring Flange and Head Cover Seal Interface*

The stay ring flange to head cover flange interface will need to be assessed for inclination, flatness on both sides, corrosion, leakages and for integrity with NDE. It is possible that due to the age of the unit minor weld repairs will be needed to restore its surface to an as-new condition.

Similarly, the O-Ring sealing groove machined into the lower deck of the upper stay ring flange may need to be restored through repairs/site machining.

The internal stud threading will also need to be cleaned and tested with possible repairs made if any of the threaded stud bores are corroded or damaged from disassembly.

3.1.5.2 *Radial Headcover Flange Sealing Surface Condition and O-Rings Seals*

The sealing surfaces likely have been internally corroded where water perhaps can now ingress up to the sealing O-Rings. This is normal and will require cleaning prior to assessment and measurement. Absolute care should be taken to preserve the machined surfaces, and any grinding or machining should not be allowed as these flanges were precision machined by Hitachi in a shop setting. Only after engineering review of the surface metrology and OEM input should any restoration that alters the surface other than cleaning should be made. The surfaces should be preserved also to prevent corrosion with oil-based rust preventative.

3.1.5.3 *Upper Runner Labyrinth Crown Seal*

Cavitation erosion can be an issue for high head runner crown seals. Bolting used on the headcover side of the labyrinth seal can experience damages from cavitation erosion even when not directly in the stream. Seal welds along the seal to headcover interface can also crack, an issue depending on the bolting design. For the Helms uprate project, regardless of chosen alternative, new runner and seals will be required.

In the areas of the inspection ports, used for taking feeler gauge measurements of the gap during unit maintenance there can also be cavitation erosion there due to the

3.1.5.4 *Facing Plates and Wicket Gate End Seals*

The facing plates, or the plates which interface with the top and bottom of the wicket gates, likely have some forms of cavitation erosion past the wicket gate bronze seals on the low-pressure side, and perhaps with some on the high-pressure side. Weld repairs and machining will be likely required. Because the wicket gate end seals are of the countersunk or pocketed design, it is likely that custom weld repair work with bronze type or dissimilar metal jigs will be required to restore the seals dovetailing. On inspection of the facing plates (Head cover and bottom ring both) it might be discovered that there has been wicket gate galling and water wiring damages if the wicket gate arm thrust bearings have been allowed to become worn out or if adjustments have not been made periodically on them. It is recommended to replace facing plates and end seals, and in general, all ear parts, with the new runner replacement.

The wicket gate end seals are made of a bronze seal sitting on a compressed rubber strip and are dovetailed into the bottom ring. They are custom machined to have a profile that works for each adjacent wicket gate, to give optimum sealing. Over time the seal may become damaged, and the supporting rubber might wear, crack or breakdown, permitting leakage. Their bolt down hardware also can break in fatigue from numerous start-stop operations as they are submerged. Replacement seals will be needed to minimize leakage of both water from the high-pressure penstock side, and from air in the runner chamber. Replacement seals are usually final adjusted on site with wicket gate clearance measurements used to determine the height and compression profile.

3.1.5.5 Operating Ring Riding Surface and Retainer

The Helms Operating Ring to headcover wear elements will likely need to be restored given the plants age and relatively high number of unit start-stop count. The retaining ring system, a steel plate which prevents the operating ring from rising when being operated is likely worn out on the operating ring surface and on the retainer plates.

Machining, with the option of adding a low friction wear surface or wear plates (Bronze or greaseless design) is an option. Regardless the system, the operating ring level, axial position and free gap or clearance will need to be assessed to determine what corrective actions are required. It is important that the operating ring gaps (Radial and axial) are within the original design criteria to prevent excessive gate leakages, additional stresses on pins and links, and to prevent lifting which can affect the servo motor internal piston seal to bore wear, as well as wear and additional friction on the linkages, and servo seals.

3.1.5.6 Bushing Bores

Because of the high head of the machine the bores which receive the wicket gate bushings may perhaps have corrosion on their surface despite their bushings being shrink fit. This would be corrected during overhaul works either through clean cuts prior to installation of new bushings (or line boring), sleeving, or localized repairs if the headcover is reused.

The bores may need to be line bored with the bottom ring if the verticality of the head cover to stay ring flange, relative to gravity has progressed outside of original installation tolerances per CEATI criteria, or if concentricity and position requirements of headcover to bottom ring bores require it. This will need to be assessed following disassembly with a survey of the stay ring flanges, and mating surfaces of the headcover and bottom ring.

3.1.5.7 Depression Air Valves and Piping

Depression air is ported into the turbine through piping at the inner head cover and upper draft tube. The area around the outlet port or pipe outlet at the inner headcover is prone to cavitation erosion on the lee sides of pump and generate mode. If left without repair the damages can remove significant material and even create holes through the headcover area. Often as a maintenance practice stainless steel overlay will be applied to the lee water passage surface areas to build up and restore the metal lost by cavitation erosion. Despite this, it is common that the erosion will still occur further radially from the pipe hole and in many cases lead to erosion at the stainless steel to carbon steel weld boundaries and create a kind of undermining erosion.

Because of the age the plant, and the plants very high head, all pipe outlets for the headcover, including instrumentation need to be inspected and assessed for long term repairs. Significant welding may be necessary for the depression valve's piping outlet at the inner headcover, which will most definitely require a weld engineering procedure and NDE examinations.

Further to this, depression air piping can often experience cavitation erosion around the elbows or transition areas along the pipe as well, and NDE and borescope inspection of these pipes would be prudent should re-use be considered.

Valve trim, and internals, as well as casing will require inspection and possible NDE to assess remaining life.

3.1.5.8 Additional Issues

The May 12th, 2020 "Helms Creek Mechanical History 1984-2018" report by Jim Stone discusses issues with the head cover drain replacement and mentions previous head cover piping failures. A repair approach to install more rigid piping assemblies with Victaulic couplings has proven successful.

It is understood the equalizing piping and support arrangement has also been found inadequate, resulting in failures of the piping, brackets, and bolting, leading to forced outages.

A modification program was executed recently on all three units to incorporate an improved arrangement utilizing Victaulic couplings and more rigid support.

Condition Assessment

Maintenance history indicates frequent inspection is performed on the headcovers, with no major damage or repairs reported – outside of the piping interface modifications noted directly above. Regardless, the headcover is approaching typical design life and will require a thorough assessment after the unit is disassembled to determine the extent of cavitation erosion and erosion-corrosion at the passage surfaces, as well as inspections to look for cracking on weld fabrications, wear on seals, flange condition, and alignment to the stay ring.

Uprate Limits

Though it is probable the existing headcover is adequate for loading associated with the pump-turbine uprate, capability for reuse of the component is expected to be both condition based and fatigue based. Past reports have indicated substantial headcover deflection when going from an unpressurized to pressurized state This – and headcover vibration during operation - has manifested in the headcover piping failures.

The headcover will need to be assessed in terms of remaining fatigue life, considering past history, an additional 40-year design life, and the increased start-stop sequences PG&E expects for future service. Though lower head units, fatigue calculations for similar vintage headcovers from Hitachi indicated structural modification or replacement was required to reach more demanding fatigue conditions with increased starts/stops.

A properly designed headcover modification or replacement headcover will be adequate for the maximum uprate condition.

3.1.6 Pump-Turbine Shaft, and Motor-Generator Lower Shaft

Estimate of Current Equipment Condition:	Good/Moderate Condition (Refurbishment and Modification Proposed)
Existing Capacity:	≥ 460 MW
Uprate Constraint:	≥ 460 MW

The pump-turbine shaft and the motor-generator lower shaft's remaining life in terms of fatigue, measured against start-stops has yet to be assessed fully. Engineering evaluation of the two shafts' remaining life is important for a refurbishment or uprate project in that the shaft can be a key component that affects the projects critical path via machining or procurement.

Assessments of shaft life will need to be made by conducting FEA using data from previous start-stop counts with NDE testing and geometry verifications of the shafts stress risers. The accumulated fatigue is analyzed first using this data to determine remaining life, which is then used as a start point for all new expected start stop, overspeed, and torsion stresses, etc. to determine a projected service life of the shaft.

Wear on keys, their alignment, clearances, journal face surface finish, coupling face alignment, precision machined coupling faces and reliefs, bores, keyway stress design, spigot concentricity, friction calculation, shaft straightness, evaluation against new hydraulic down thrust, maximum operating torques, etc. for the shafts are then also assessed against its as found condition to see if modification is feasible.

Successful reuse of a shaft via its adaptation to a new turbine depends on the geometry of the shaft (particularly at changes in section), material properties of the shaft at its minimum diameter, of the coupling at the runner to turbine-shaft interface, and at the generator rotor to generator-shaft interface (i.e., pull out stress for the female threaded bores), and availability of keying or shear sleeve locations. Material testing to verify the actual properties of the shaft material at the forged coupling ends is an important first step in assessing the shaft's ability to be adapted to a new turbine that can be done without disassembly of the machine early in the planning phase.

A shaft refurbishment is done after the disassembly phase is completed. Options for a spare shaft prior to the refurbishment phase is sometimes executed as insurance against the critical path if evidence of large cracking or incipient failure is observed on a sister unit or unit worked on prior to the refurbishment. In such a case usually only the material or a rough machined shaft is prepared so that it can be custom machined to suit the specific unit's unique geometry, length, and clearances. Sometimes a spare shaft is planned but not executed prior to project commencement also.

Issues for the shaft which will require intrusive engineering analysis and inspection include:

- Principal Stress Analysis
- Fatigue Analysis
- Turbine Shaft Couplings Design to transfer the new torque
- Coupling Torque Keys and Shear Sleeve modifications (Turbine and Generator)
- Turbine Shaft Coupling Flatness Machining Criteria (Turbine and Generator)
- Turbine Shaft Spigot Concentricity (Turbine and Generator)
- Turbine Shaft Fatigue Life and Stress Risers
- Turbine Shaft Journal and Bearing Preloading, and Past Bracket or Oil sump deflection Issue
- Turbine Seal Shaft Sleeve Refurbishment, i.e., new sleeve versus weld overlay

3.1.6.1 Existing Shaft Maximum Uprate

An allowable stress analysis of the torque carrying components of the turbine shaft line was performed to determine existing powertrain limitations. Torque carrying limits were identified for the coupling/runner connection, the shaft itself, and the main shaft coupling. The allowable uprate capacities are based solely on typical industry standard allowable stresses (i.e., 1/3 yield strength, 1/5 ultimate strength for normal conditions) and primary membrane stresses. As noted above, a through stress and fatigue analysis would need to be performed to identify peak stresses, hot spots, and to evaluate remaining fatigue life.

Table 3-12 summarizes the analysis results, which suggests the torque carrying ability of the existing shaft is adequate to 475 MW.

Table 3-7. Maximum Pump-Turbine Shaft Limits

Component	Pump-Turbine Shaft Max Allowable Uprate (MW)
Shaft based on Torsional Shear	475
Shaft based on combined Von Mises	594
Runner to Shaft Key	478
Shaft Coupling including Bolts	N/A (see below)

For the shaft coupling bolts, max Uprate in MW is not meaningful. Bolt loading limiting criteria typically depend on hydraulic thrust and runner weight; although there is some correlation between MW and hydraulic thrust and runner weight, it will not be a direct one. Since the Helms' bolt stress is less than 20% of the allowable bolt stress, a significant increase in MW should be feasible, provided that the hydraulic thrust and runner weight do not exceed the bolt load capacity. Regardless, it is suggested the coupling bolts be replaced during any overhaul/uprate, and calculations considering any changes to the hydraulic thrust and runner weight would be performed.

Condition Assessment

Maintenance records of the past twenty years do not indicate any present issues with the pump-turbine shaft.

The shaft, keyways and couplings will need to be assessed with FEA to determine the remaining fatigue life per above written description. Already the shaft has seen a typical service life and it will be essential to assess the shaft prior to the outage to determine if a replacement is warranted. The main challenge however for PG&E will be that FEA analysis must be supported with field inspection and NDE to verify assumptions on its “As Found” condition. Therefore, during the first outage a decision on whether to purchase a partially machined shaft or to wait for disassembly phase and asses the shaft will need to be made. This will be a major risk to the critical path, and an important outage planning decision, as a partially machined shaft (one that could be final machined to interface with the pump-turbine and motor-generator) can be very expensive.

Uprate Limits

Preliminary shear carrying calculations for the pump-turbine shaft suggest it could be adequate for an uprate to approximately 475 MW, however, calculations are based on shaft cross sections, and do not consider peak stresses and associated loading cycles that would be studied further in fatigue analyses. Allowable stresses are based on typical shaft material mechanical properties – actual coupon testing suggests these values are typically exceeded.

Capability for reuse of the component is expected to be both condition based, and fatigue based.

3.1.7 Stay Vanes and Spiral Case

Estimate of Current Equipment Condition:	Good Condition (Refurbishment Proposed)
Existing Capacity:	≥ 460 MW
Uprate Constraint:	≥ 460 MW

The stay vanes and spiral case steel weld seams and joints require NDE testing and an engineering analysis to determine its condition. Stay vane modification might be recommended for a new turbine design to improve efficiency and to possibly mitigate erosion issues on the water passage surfaces. Stay vane modification is a (potentially) intrusive process, and during detailed hydraulic design OEMs will verify whether modification is required/suggested for optimum hydraulic performance or if improvements are not significant enough to warrant the time/cost to execute in the field (potentially on critical path). Fatigue analysis will be required to verify existing arrangement is suitable for increased loading/unloading cycles during start-stop sequences on the spiral case and stay vanes.

The existing spiral case design pressure is 2,510 ft of head, representing a 30% increase on the maximum static head from upper reservoir pressure. While the

Condition Assessment

An NDE examination will be needed to determine the existing stay vanes and spiral case condition prior to, or during the beginning of the overhaul. Typically, the painting system is replaced during a major uprate or overhaul, with NDE done on the spiral case welds, spiral case doors, embedded piping outlets, and any stress risers. This is an important assessment for underground, high head machines. Refurbishment of the spiral case can be worked into the turbine contract with either the turbine OEM or another contractor. If stay vane modifications are required to achieve a larger power output (Does not seem to be the case for Hitachi Options A or B as they have proposed) then project coordination and planning between the contractors will be necessary to determine the critical path concerning access to the turbine and stay rings.

Presently no major issues are reported, however an intrusive inspection with NDE is recommended even prior to the project outage to get as much assessment done early.

Uprate Limits

Pending results of fatigue and condition assessment, it is expected the existing spiral case and stay ring can support a turbine uprate. The final pump-turbine design will decide if the stay vanes require modification such as upstream/downstream extensions, internal grouting, welding, reprofiling, etc.

3.1.8 Wicket Gate System & Operating Ring

Estimate of Current Equipment Condition:	**Good/Moderate Condition (Refurbishment and Modification Proposed)**
Existing Capacity:	≥ 404 MW
Uprate Constraint:	≥ 460 MW

3.1.8.1 Wicket Gate links, pins and bushings, and operating ring

The Helms plant has a 20-wicket gate arrangement, controlled by two double regulated governor-operated servomotors, with a typical operating ring. A pump storage hydro unit typically receives many more start stops than traditional base loaded plants, and as such the wicket gate link pins and bushings as well as the wear blocks of the operating ring tend to depreciate and age faster than the typical base loaded units. Pin wear, and bushing wear lead to lost motion due to the gaps developed and as such can lead to reduction in squeeze on the gates during shut down. Also, changes due to wear on the eccentric pin, bushing or locking mechanism which holds the eccentric in place can lead to deviations in the final as set “gate circle,” and possible openings or gaps at the blade tip to tail interface. As such, for a pump storage plant, additional maintenance work and overhaul work is often required at increased intervals.

The gate and link system are presently a grease lubricated system with bronze bushings. There has been a trend in the last several decades to replace grease lubricated bronze bushings with greaseless self-lubricated designs, often a composite type of material like Orkot (a brand name) or CIP, among others – but many pumped-storage installations have retained greased bronze bushings.

Regardless of the alternative selected for future work the wicket gate linkage mechanism will need to be inspected and overhauled, and replacement wicket gate mechanism bushings installed.

3.1.8.2 Wicket Gate Arms and Thrust Washers

The wicket gate arms appear in good condition and are not mentioned as having any issues. During an uprate or a refurbishment NDE and geometry checks, followed with new bushings, and repainting is a typical recommendation. If the arms are found to have wear or galling at the thrust washer surfaces or on any of the sliding interfaces, then localized repair may be called for. They would be shipped to the shop and doweled with the new wicket gates.

For high head machines, with relatively small or light weight wicket gates there is possibility for hydraulic thrust or uplift of the gates if the lower wicket gate bushing seals are not adequately designed or if they have excessive wear from years of service. Once the high-pressure headwater can infiltrate past the lower wicket gate stem seals (In the bottom ring) then the hydraulic pressure on the underside is in opposition to the head cover air pressure, and naturally an upthrust on the gate occurs tends to close the gap of the wicket gate to the head cover facing plates. To prevent wicket gate to facing plate contact a designed wicket gate gap is chosen by the designer in addition to the seal design, which considers head cover diaphragm movement or flexing, and either a thrust surface is included in the stem bushing, or a wicket gate thrust bearing is designed into the wicket gate arms, or a combination of two sometimes. For Helms, due to the plants high head pressure this thrust washer is very important for preventing wicket gate to facing plate contact and galling damages. Galling damages can permit water to bypass the gates when the machine is closed leading to leakage and sometimes unit creep possibilities if galling is widespread, as well as high decibel sound level issues in the turbine pit, and lost water from the upper reservoir.

Figure 3-10 below shows the original wicket gate thrust washer design. On recent upgrades and modifications of pumped storage plants a greaseless or composite thrust washer type design has been attempted, with mixed results. Engineering assessment of the present wear, and grease system will need to be undertaken as part of any uprate or refurbishment. More environmentally friendly grease products are now available on the market if this is an issue with licensing or operational regulations. A decision on going greaseless will require careful engineering review of past operations, forensic examination of the existing condition, and consultation with the OEM and potential bushing suppliers concerning the material properties and performance records at pumped storage installations of the product and material pairings chosen.

[redacted]

Note: Red highlight on right hand diagram is the area for refurbishment or modification.

Figure 3-10. Wicket Gate Thrust Washer Diagram with Grease Port Shown

3.1.8.3 Restraining Mechanism

Helms is equipped with a wicket gate restraining mechanism. It is of the friction disc-spring type design. This prevents violent and damaging free swinging of the wicket gate (dampens gate free swing oscillations) should its shear pin break while the unit is operation, helps reduce pressure pulsations to the turbine, as well as mitigates overall damage from the gate arm swinging into other gate arms or links (although does not fully protect from damage).

The spring compression was determined during original design calculations and start-up testing and is precisely engineered.

3.1.8.4 Wicket Gate Head Cover and Bottom Ring Bushings and Seals

The original wicket gate seals design is of a chevroned or V-shaped packing gland design (Figure 3-11). This design seems adequate, however there are now improved sealing designs which take advantage of new material properties and geometry to help reduce wear and to prevent bypass leakage and aging. On plants this age, it is common that the packing is beginning to become an issue with small leaks, usually resulting spraying or leaking into the turbine pit area. Where any leaks have developed, or if there is standing water in the area of the packing gland and adjusting plates, then corrosion at the packing gland becomes an issue.

For any unit uprate or redesign, the wicket gate stem packing should be reassessed with a modern design considered. As a part of refurbishing or changing the packing system, usually line boring, with sleeving or line boring with weld repairs, or line boring alone will need to be considered. Any machining done to the head cover will need to consider the headcover's verticality, or skewness. It is easiest to line bore or machine with the head cover in place after all stay ring flange repairs or machining is completed to ensure good concentric alignment and verticality for the packing, bushings, and wicket gate stem penetrations.

[redacted]

Note: Improved designs are available.

Figure 3-11. Original Wicket Gate Packing Diagram, Upper Stem Seal

3.1.8.5 Grease System

The grease system and its distribution valves are likely nearing end of life which is typical for a plant of this age. Going forward engineering analysis and decision will need to consider what components should be replaced or modified to incorporate greaseless design as part of the refurbishment or uprate project.

It has been our experience that full replacement of bronze greased bushing and wear plates with greaseless is not always advised, as greaseless bushing and wear plates have their own issues with decreased lifespans depending on loading, turbine pit moisture, and water quality.

Keeping the bronze design is advised for the wicket gate bottom ring and upper stem bushings based on pumped-storage experience and expensive disassembly costs required if issues arise early after retrofit or upgrades. However, there could be less concern with using greaseless style (e.g., Orkot, CIP, etc.) bushings for the wicket gate linkages and operating ring. Use of greaseless bushings for the wicket gate arm thrust bearing surface has had issues on another similar pump turbine Hitachi machine though, and conversion to greaseless for that would merit an analysis.

<u>Condition Assessment</u>

Maintenance records indicate gates and clearances are regularly inspected, with gate stem packing, end seal components, and bushings replaced as needed. Wear on pins bushings, thrust washers, and wear pads, as well as gate seal leakage (Or just wear) on the wicket gate stems is typical for a machine of this age and service. Wear also and aging of the rubber on the wicket gate embedded seals at the headcover and bottom ring is also likely. It is usually therefore recommended that an NDE assessment be performed after about 20 to 40 years of service, or earlier if telltale signs or operational issues present such as hunting, excessive gate leakage or stiction issues during operation. A full refurbishment of the gate linkage and operating ring system is normally recommended to be performed around after 40 years of service life, subject to operational experience and assessment.

<u>Uprate Limits</u>

Reassessment of the wicket gates links (for condition), pins (against new loading and fatigue) and gates (against profile and stress risers and condition) will need to be done as part of any uprate or turbine replacement. If an uprate option such as the proposed Hitachi A or B option is selected, then it is likely that minimal modifications will be required to mechanism components with just wear components replaced. Also, the operating ring stresses, and fatigue should be assessed should modifications to the servo motor pressure, stroke or forces be made as part of a design change.

3.1.9 Wicket Gate Servo Motors

Estimate of Current Equipment Condition:	Good Condition
Existing Capacity:	≥ 460 MW
Uprate Constraint:	≥ 460 MW

The servo motors, their wear rings, piston rod, cylinder, internal bore, packing seals, are all typical refurbishment items for the age of the plant. It is understood from plant personnel that these items have been wearing faster than usual, most likely attributed to increased start-stop cycles and more frequent cycling in general. The existing servomotors require some disassembly in place and a substantial effort for some refurbishment, so there is some desire for improvement when it comes to maintenance.

In addition to standard overhaul work, alignment and total stroke may require minor modifications depending on what alternative option is decided upon.

Increasing the total stroke can sometimes be achieved by internal machining of the stops or by cylinder machining, however this is usually for only marginal gains. Depending on the alternative chosen it might be necessary to have the servomotors replaced if machining modification is limited in terms of stroke being added at the cost of loss of strength of the cylinder and bore, or potentially if a governor upgrade is simultaneously performed as the industry trends towards higher pressure governor systems.

The concrete foundation for the servomotors will need to be evaluated for integrity if the pressures are increased as part of any modification of the servo design. Per original drawings the servomotor foundation/anchorage is designed for a horizontal force of 597,555 lbs.

Also, presently there appear to be no known issues with the wicket gate closing rate, or water hammer. A change to the turbine could require a change of wicket gate timing from the governor, but also an adjustment made to the cushion setpoint of the servo motors.

Sometimes for unit overhauls or uprates a new servo motor set is manufactured and made ready to replace the first units set. The removed set is then “leapfrogged” into the next unit once refurbishment is completed, with the final set being kept as a critical spare. This should be considered for the uprate project, knowing that the servo motors are an important item that can eventually create delay on the critical path.

Pre-design activities for this system include:

- Perform a preliminary condition assessment on the servos to estimate the mean time between major refurbishment using the last refurbishment time as a basis. Assess the present servo motor leakages across the cylinder seals, and out of the piston rod / shaft packing. Assess the pins for migration and alignment and rod surface condition. Use this info for planning of the outage.

<u>Condition Assessment</u>

The condition of the servo motors is reported to be in good condition, with no major issues presented. A full assessment of their operations included oil leakage at the seals (drifting), and rod (external leakage), alignment as they are extended, looking for stiction, and internal inspection looking for wear and measuring against design clearances should be done as part of the refurbishment to determine what refurbishment work might be required once the unit is disassembled. It is typical to replace the piston seals, re-machine the inner bore, resurface the main rod, and replace the rod packing, as well as replace or refurbish the cushion valve trim.

<u>Uprate Limits</u>

It is understood existing servomotors have adequate stroke to accommodate an uprate to 460+ MW and it is expected loading would not be beyond existing capability. Modification or replacement of the servo motors will depend on the final turbine design. Typically for a small power uprate the servo motor system may be refurbished rather than replaced, subject to condition and load forces.

3.1.10 Head Cover Runner Band Drain Valves

Estimate of Current Equipment Condition:	Unknown Condition (Replacement Proposed)
Existing Capacity:	≥ 460 MW
Uprate Constraint:	≥ 460 MW

The lower runner band drain valve is a critical valve needed to drain off excess water leakage past the wicket gates when the unit is spinning in air. When opened, the valve and drain prevents water build up and violent vibration felt on the pump-turbine from water being spun around between the pump-turbine runner blade tips and back of the closed wicket gates. They also allow for water egress, which if not permitted can cause heating of the lower runner band area, and thus help assist cooling.

It is critically important that these valves function properly and that they are not allowed to be open when the runner is spinning in water. If they were to open when the runner is spinning in water, they could create a hydraulic imbalance that can lead to high radial vibration and perhaps catastrophic lower runner band failure. If left open, they also can dramatically change the axial forces on the machine, much like as the equalization pipes do, and lead to thrust bearing failure.

As such, it is important that these valves, their controls, actuators, and integration into the auto start and automatic controls be well maintained. For any type of unit uprate or overhaul this drain system will require intervention. It should be noted that the lead time for valve casings has increased, and it could be 8 months to a year to receive replacement parts depending on availability.

Pre-design activities for this system include:

- Assess the valves, their actuators, and verify their operation with the auto control system. With the information gathered reach out to vendors to assess lead times for replacement valve body and custom trim. Assess the piping also to determine if piping replacement is required during the outage to achieve new service life criteria.

Condition Assessment

The valves and the control system need to be assessed; their present condition is not known to Stantec. Maintenance records indicate more recent flange bolting replacements, as well as an occurrence in 2017 where one of the valves failed to open during pump start.

Uprate Limits

The new pump-turbine design will have a predetermined design for its drainage flow rate, but requirements are expected to be like existing conditions. Wicket gate leakages during pump start (or condense) should decrease, if anything, following overhaul and will be subject to performance guarantees. Outside any condition-based replacement, it is expected the runner band drain valve can be reused for the uprate condition as service requirements should not increase. Assessment will be required by the OEM to verify the existing valves and piping can be utilized.

3.1.11 Turbine Guide Bearing

Estimate of Current Equipment Condition:	**Moderate Condition (Replacement / Modification Proposed)**
Existing Capacity:	404 MW
Uprate Constraint:	≥ 460 MW

The turbine guide bearings performance does not show any major issues after performing a preliminary review of some of the data provided. It is noted that the bearing does experience a pronounced thermal effect for the first half-hour of service when the unit is started from a cold condition, where the peak-to-peak shaft run out magnitude is higher than steady state condition, with its overall run out magnitude decreasing as the turbine shaft journal and turbine bearing tub and bearing trend to thermal equilibrium. It is possible to affect this issue with controlling cooling water supply flows however such controls and tweaks are difficult to set definitively over different seasons.

The turbine guide bearing preload, as well as the bearings stiffness and oil wedge thickness will require engineering assessment with the OEM should the unit be uprated in terms of turbine power. Bearing stiffness, in coordination with head cover stiffness, will need to be considered during a standard shaft-rotor dynamic study/critical speed analysis made by the OEM.

The bearing instrumentation is often upgraded during unit overhauls or power uprate projects. As part of the upgrade specification RTD wells for measuring the bearing babbitt temperature can be refined, with locations being placed so that unit side loading or uneven bearing loading can be detected. Proximity probes and accelerometers can be specified as well with care going to their wiring or cabling to prevent wire jacket deterioration, breakages, etc. As a part of the bearing instrumentation, for both the turbine guide bearing and the other bearings, the interfacing boundary of the oil sump sometimes needs to be redesigned so that the wiring can penetrate the bearing oil sumps (Oil Pots, or tubs). Making a robust and leakproof set of penetrations can be a challenge, so a proper specification on leakage for instrument penetrations should be worked into the final project technical specification.

Pre-design activities for this system include:

- An assessment of the existing instrumentation and its performance and reliability should be done to determine what additional instruments or additional locations should be planned for to support testing, commissioning, and contract guarantees, and their final role as part of a condition monitoring systems.

Condition Assessment

The turbine guide bearing presently has a design shortcoming related to thermal expansion. Hitachi has provided recommendations on modifications, however, to date a bearing modification has proven impractical due to required operations of the machine. An overhaul, or unit uprate outage would be an ideal time to modify the bearing.

Other than the known thermal issue – we understand the bearings have been functioning adequately. The Unit 2 bearing was refurbished in 2012 but records do not indicate when Unit 1 and 3 were last refurbished. Samples are frequently taken to monitor bearing oil content.

Uprate Limits

It is expected the existing bearing system could be reused for the uprate condition but depending on the pump-turbine redesign, the oil wedge thickness, bearing clearance and bearing preload may require modification. If the preload or oil wedge thickness and the stiffness of the oil wedge needs to be changed significantly then and cannot be modified with the existing steel pad design (limitation mainly being the available babbitt thickness available to machine) then new pads might be required.

3.1.12 Cooling Water System

Estimate of Current Equipment Condition:	Good Condition (Refurbishments and Modification Proposed)
Existing Capacity:	≥ 460 MW
Uprate Constraint:	≥ 460 MW

3.1.12.1 Turbine Cooling Water System

The cooling water system supplies water to the Turbine Guide bearing (167 gpm), Packing Box (67 gpm) and upper and lower seals (270 gpm). The water supply to the bearings, shaft packing, and upper and lower turbine seals are all critical systems for plant operations. Both their condition and capacity will need to be considered for future upgrades, and or overhauls on the units.

3.1.12.2 Flow Considerations

The cooling water supply to the turbine guide bearing, as well as that to the thrust / main generator guide bearing, and upper guide bearing could be affected if additional flow and pressure is required for a generator stator (Unit uprate) modification. If additional flow is required for a new or uprated stator (to offset additional core losses which inevitably occur from a power uprate) then adjustment of the flowrates and valve openings for the other bearings will likely be required. It is feasible that there might be limited flow available for the guide or thrust bearings as a result of upgrades. If this is the case, then the cooling water pump and power (Motor) might need to be modified or upgraded also.

Prior to any unit uprate or power increase the cooling water flow requirements for peak summer heat (and associated peak cooling water temperatures), and loading should be examined for the stator, and bearing cooling coils. It would be prudent to have the water flow rates for the bearings and stator recorded and documented. This way they can be compared to the uprated units flow rates and checked against future projections for inlet cooling water temperatures as well.

The cooling water inlet and outlet valves should receive an updated condition assessment, with operational history queried from the operators for the purpose of replacing them prior to a unit uprate. For the first unit uprate, the planning for high-precision flow meters on the bearings and stator’s cooling water discharge lines should be considered. These will be needed for any thermodynamic efficiency tests and can help operations set up the new cooling water flow rates too.

3.1.12.3 Present Known Issues

Bearing tub temperature effects (i.e., cold start conditions) should be analyzed to avoid thermal-induced vibration - such as clearances being adversely affected by early expansion of the shaft journal’s diameter on initial warm up, with delayed thermal expansion of the tube resulting in bearing clearance issues either too small or too large. Analysis typically consists of a small report made from trending start-up and shut-down conditions for summer and winter seasons versus radial shaft vibration magnitude trending. The CEATI Generator Turbine Vibration and Balancing Field Guide (Report No. T162700-0392) has a good example of similar large (400 MW) Hitachi Pump turbine guide bearing thermal trend identifying journal sleeve and bearing clearance effects as an example (Figure C.49). Documenting any effects now can help later also with preparing modifications to the bearings as needed for the uprate (e.g., Pre-load changes, stiffness modifications, oil wedge design, heating effects, vibration performance prior to uprating as a baseline, etc.).

Condition Assessment

An assessment on the existing cooling water system should be conducted as a part of the preparation for the unit uprating or overhaul.

Uprate Limits

Flow requirements for the bearings, shaft seal, and stationary wearing rings are not expected to increase significantly with an uprate – but it is understood the existing system is marginal when source temperatures are high and/or reservoir level is low. It is possible that a new motor-generator may require more cooling water flow than the existing generator because of increased power (I^2R losses). As such, an assessment of summertime water flow to the motor-generator surface air coolers should be done to determine available water supply to be shared with the generator manufacturers.

3.1.13 Shaft Seal and Clean Water System

Estimate of Current Equipment Condition:	Good/Moderate Condition (Refurbishment or Replacement Proposed)
Existing Capacity:	≥ 404 MW (to 460 MW perhaps)
Uprate Constraint:	≥ 460 MW

The shaft seal, and its main plate which interfaces with the head cover and its bolting will need to be assessed to determine if there are any resonance or fatigue issues on the bolts during disassembly.

The adaptor plate itself likely requires weld repairs from erosion-corrosion and perhaps some galvanic corrosion based on its age. Usually, the adapter plate is inspected and replaced with a stainless design, unless the existing condition is found satisfactory. High velocity of water occurring between the rotating shaft and the head cover area can create erosion corrosion along the headcovers parent steel in proximity to the shaft, which then increases pre-shaft seal gap resulting in slightly larger pressure at the shaft seal. In cases where this has occurred weld repairs can be made to restore the clearance to original design criteria.

The shaft seal design should only be changed if there are maintenance issues, or excessive leakages or wear on the turbine shaft that might not meet a criterion for the plant’s drainage or desired future service life. New, modern designs for shaft seals exist, however sometimes switching designs can be regretted especially if the original design has had little issue.

The shaft seal’s clean water supply system is critical in reducing wear on the shaft seal carbon segments, and the on the steel at the shaft sleeve or liner. If the shaft seal design is changed, total available water flowrate, its cleanliness, its chemistry, as well as any seasonal biological fouling issues will need to be designed into a replacement design.

The existing wear on the shaft seal’s turbine shaft wearing sleeve or interface should be measured and considered to help determine whether a redesign might be recommended.

Condition Assessment

Records indicate regular maintenance is performed on the shaft seal and its service water supply components to address leakage and replace components. Though not clear which unit, it appears a shaft sleeve was replaced in 2007.

An inspection of the shaft seal housing, hardware and flange will be necessary to determine its condition. It is typical that the shaft seal is either refurbished or replaced due to corrosion issues or during major unit uprates or overhauls. The shaft sleeve on the turbine shaft is also usually refurbished with weld repair and machining or by machining and installation of a shaft sleeve. An assessment will be needed to determine which is the best option prior to the outage.

Uprate Limits

Usually, the shaft seal can simply be refurbished or replaced with a new or like for like design during unit uprates. This depends on the new design pressure which will be experienced at the shaft seal and past performance issues with the seal itself. Pending any operational input from PG&E, and with similar pump-turbine crown seal arrangement and transient conditions, then it is expected the present design could be maintained for the uprate condition.

3.1.14 Governor

Estimate of Current Equipment Condition:	Good/Moderate Condition (Refurbishment and Modification Proposed)
Existing Capacity:	≥ 420 MW
Uprate Constraint:	≥ 460 MW

The Helms governor cabinet has received modernization modifications which were done by the American Governor Company, and it now employs redundant PLCs and an operator HMI screen. In general, a period of about 15 years is considered a typical age for replacement of Governor PLCs and transducers. This is driven primarily by PLC equipment becoming obsolete and HMI interface failures.

The cabinet's pilot valve, main distributor valve, and supporting oil pumps should all be assessed with refurbishments made to the distributor and piolet valves, with possible replacement or upgrades considered for the oil pumps and check valves recommended to ensure reliability and safe operations of the governor system. The oil cleanliness and its filtration should also be included in a refurbishment or upgrade scope to ensure it meets recommended ISO cleanliness criteria.

Depending on the alternative chosen, if the present servo motor internal volume, stroke and oil operating pressure can be kept with the new turbine design then assessment would the recommended. The governor's oil accumulator tanks and oil piping should also be assessed.

The total volume of oil, and ability for the governor to perform an emergency shutdown operation from an operating position will need to be verified as part of any governor upgrades or modifications, this is mentioned as it is sometimes overlooked, and depending on oil volume requirements a new accumulator tank or pumping rate may be required. The low oil level switches, alarms, and trip relays are a part of such an assessment also.

The governor will need to be programmed for new wicket gate closing times with a new turbine also to ensure transient overpressure (Water hammer Effect) during unit trips or emergency stops are within penstock criteria.

The governor's gate position indicator and piolet valve position indicator should also be assessed against obsolesce and replaced accordingly to prepare the unit for a new service life.

<u>Condition Assessment</u>

The governor has been modernized. The governor cabinet's valving, feedback transducers (Servo Motor position indicator, and distributor valve position indicator), piolet valves, distributor valves, solenoids, PLCs, oil filters, wearable components like the dithering mechanism, etc. all require periodic maintenance and calibrations, however. As such, in order for the governor to match any life extension from an overhaul or uprate the governor will need to be assessed by governor SME or OEM so that the unit upgrades can be coordinated and planned with a governor refurbishment. The oil pumps for the servo motor accumulator tanks should be assessed to determine if they need replacement or overhaul prior to the main project outage.

<u>Uprate Limits</u>

The turbine OEM will need to provide information to inform the owner of the servo motor pressure (Presently at 1,000 psi) and volume requirements for any major turbine modification. In many cases the existing governor systems, namely the servo motors can be reused with minor governor modifications made. This will need to be determined however as part of the preliminary engineering design phase with the turbine manufacturer.

3.1.15 Draft Tube

Estimate of Current Equipment Condition:	**Good Condition (Refurbishment and Modification Proposed)**
Existing Capacity:	≥ 404 MW
Uprate Constraint:	≥ 460 MW

3.1.15.1 Upper Draft Tube

<u>Piping Interfaces</u>

The draft tube piping interfaces for air admission, instrumentation and depression air piping, and pressure taps will require refurbishment based on their age. It's likely that cavitation erosion has occurred on the water passage surface around the inlet/outlets, and that welds made on the piping to liner interface may be reduced in volume and or cracked. In the areas nearest to the turbine outlet weld repairs around the pipes might be required to restore the surface due to cavitation erosion.

Draft Tube Door

The draft tube doors will require NDE inspection to verify geometry and likely repairs to ensure integrity. Any issues with the door and leakage should be discussed. If there is leakage at the draft tube door, due to broken pipes or less likely at weld seams, then blasting, repairs, and new protective coatings on the door area will be required. Any drainage or standing water near the door should be documented in consideration for repairs.

Liner Cavitation Erosion

Because the upper draft tube is so close to the turbine runner outlet discharge and lower runner band seal, the immediate liner zone will likely require repairs. Access ports to measure the turbine runner lower runner band clearances may also require refurbishment due to cavitation erosion made from the years of service.

3.1.15.2 Lower Draft Tube

The welds and faceted surfaces of the lower draft may have some minor cracking with erosion-corrosion likely also at steep transition zones between panels. Refurbishment at a minimum of the draft tubes corrosion protection system (Paint) should include NDE of the welds with minor weld repair as necessary to prevent leakages.

The steel to concrete interface should also be inspected with hammer test at a minimum to determine if there are any voids between the steel and concrete. Grout injection is typical in cases where large voids are discovered.

3.1.15.3 Balancing Pipes (For thrust bearing down-pressure adjustment)

Helms has an orifice-based equalization line system with equalizing lines communicating between the draft tube and inner head cover area. The orifices were set during start-up testing to establish a good pressure on the thrust bearing pads.

For such high head pump storage units often the balancing piping inlets, located in the draft tube, need to be inspected and weld repaired periodically due to cavitation erosion damage on the lee side of the pipes (both pump and generate directions). Depending on the extent of cavitation erosion, sometimes liner repairs and welding to the pipe to liner interface may be required.

Sometimes, replacement orifices may be needed to restore the design diameter due to cavitation erosion. These should be checked periodically particularly if anomalies in downthrust or thrust bearing oil / pad temperature are experienced.

3.1.15.4 Cooling Water Supply Inlets, and Other Piping Interfaces with the Draft Tube

The piping inlet/outlets for the cooling water system, sump and dewatering discharge, draft tube drain, will all need to be inspected and refurbished to achieve a life extension.

The cooling water for the Helms units and liquid rheostat is supplied from the draft tubes. The cooling water inlets are located at the end of the draft tube, just before the draft tube gates. NDE inspection will be required with refurbishment likely needed due to years of exposure to corrosion and flow. It is typical that these inlets, and their grates or trash screens require replacement.

The draft tube drain, and its screen will also likely need refurbishment. In some cases, also, the instrument tubing for the drain lines gets clogged with tightly packed sediment and becomes inoperable. These lines will need to be inspected and possibly replaced if flushing is not feasible.

The sump and dewatering discharge piping outlets will also require NDE inspection and refurbishment as necessary.

Condition Assessment

The draft tube steel and its piping interfaces will need to be assessed as part of any uprate or unit overhaul. NDE inspection of all welds and interfaces is best for this.

Maintenance records indicate some work to the man doors has been completed in the past. If still an issue, sealing surfaces might be restored through weld repair and grinding.

Uprate Limits

Outside of typical overhaul work, it is expected the draft tube could be reused. The draft tube will likely need to be modified to permit any large power increase as part of an uprate or unit overhaul. As noted in the Hitachi Plan B design, substantial draft tube modification could be required for uprate to 460 MW. However, other OEMs may propose different hydraulic designs that could permit uprate without a wholesale change to the draft tube hydraulic profile. While modification to the upper liner is reasonable and economically viable (representative of the Hitachi Plan A / 455 MW uprate) – a solution involving a completely new draft tube is not desired. We would recommend this become a restriction for any uprate approach for competing OEMs.

3.2 MOTOR-GENERATORS

The Helms motor-generators were originally designed and supplied by Westinghouse, designed for high technical severity as they required a high-power density regarding MVA/pole and placed in commercial operation in 1984. The design of the machines was driven to a large extent by the maximum size and weight limitations of the components, due in part to the remote site locations and the elevated high altitude.

Those factors resulted in a high speed and high voltage machine, having water cooled wave wound stator windings, direct water-cooled thrust bearings, a long stator core, and large pole and field windings. At the generator mode, the rated capacity was 390 MVA, 18 kV, 60 Hz, with a PF 0.90 at rated speed of 360rpm, in counterclockwise direction view from the top, and overrated capacity of 448.5 MVA. As a motor was rated to 347.2 MW at same power factor with rotation in clockwise direction.

Each of the three units in the powerhouse consists of three bearing shaft layouts with an upper guide bearing, lower combined thrust and guide bearings, and turbine guide bearing.

The ventilation is provided with surface air to water coolers with a natural rim ventilation system pumping air with the spider arms through the rim ventilation channels, in addition to the forced air ventilation supplied by electric motor fans. Located inside a cavern at a high elevation altitude, the air density reduces significantly and so the heat transfer by air convection is limited. Therefore, the stator windings were specially designed with water cooled bars and a pure water-cooling system to meet the required output with temperature rise limits of 60°C for the stator winding and 80°C field windings. Refer to Figure 3-12 below for details relative to the Westinghouse Generator-Motor and Figure 3-13 for section view of the generator.

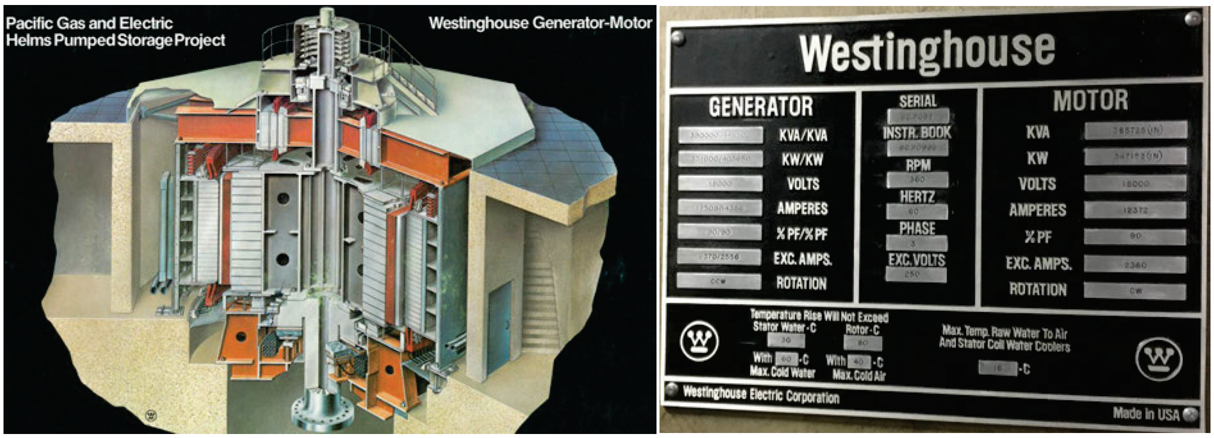


Figure 3-12. Generator Arrangement and Nameplate Data

[redacted]

Figure 3-13. Section View of the Generator

Table 3-8 summarizes the pre-design work scope to achieve the Motor-Generator target uprate:

Table 3-8. Generator Components Condition Assessment

Component	Condition Assessment	Scope
Motor-Generators	Complete new stator and new poles, new upper bracket and bearing and MOD spider, and Rehab to improve the remaining components, the generator is suitable for the uprate from current 404 MW (PF 0.90) up to 460 MW (PF0.90).	UPGRADE
Electromagnetic and Ventilation Design	Improve ventilation at the poles and main terminals Keep magnetic pull to improve rotor dynamics Check new stator natural frequencies to avoid resonances	MOD
Stator Windings	Improve dielectric distances and magnetic distances to avoid induction heating. Replace to resolve the core hotspot issue Replace stator winding water cooling system modern design	NEW
Stator Core	Hot spot issues on all three units. Replace new core fixation system with thermal expansion free	NEW
Stator Frame	FEA and NDE to be performed. Rehab vs New (cost, lead time and scheduling comparison) Improve the fixation with the soleplates	MOD/NEW
Rotor Poles	Existing poles issues (Nomex migration, coil gaps), field and damper winding thermal limits, excessive copper movement and ventilation deficiencies are major concern for the long-term solution. Recommended to be replaced.	MOD/NEW
Rotor Spider	Spider support lips with line contact due to rim stacking issues and uneven load distribution. Perform detailed FEA analysis to identify mitigation plan	MOD
Rotor Rim	Stacking, leveling and roundness issues. FEA shows stress in acceptable levels. Recommended to perform FEA analysis and inspections to confirm the residual shrinkage level and floating speed.	REHAB
Brakes/Jacks and Braker Ring	Hot spots, cracking and fixation looseness. Recommended new brake rings with thicker segments and new brake/jack system. Verify the possibility for electrical assisted braking	NEW
Generator Main Shaft and Couplings	Torsional stresses are higher than allowable values. The von Mises stresses are within allowable limits. Perform a detailed FEA and fatigue analysis to confirm the uprate limits and remaining life evaluation considering the stress concentration regions.	MOD/NEW
Rotor Dynamics	Recommended to improve the upper bearing stiffness to improve dynamic performance	MOD
Generator Stub Shaft	New stub shaft to accommodate the new upper bearing layout	NEW
Thrust & Guide Bearings	Rehab the existing water-cooled thrust bearings with certified suppliers. Confirm the hydraulic thrust load and cooling system capacity	REHAB

Component	Condition Assessment	Scope
Combined Thrust and Guide Bracket	Confirm the new hydraulic thrust load. Perform FEA and fatigue assessment NDE inspections	MOD
Upper Guide Bearing and Bracket	New upper bearing layout to reduce the distance to the magnetic centerline and increase overall stiffness support to the foundation	NEW
Foundation Soleplates	Shear stress on the dowels is above allowable value for short circuit condition. Perform a civil engineering review on the foundation loads. Confirm leveling, roundness and concentricity. Procedure and tooling required for the stator soleplates MOD process	MOD

3.2.1 Assessment of the Existing Condition

Historically, the OEM Westinghouse motor-generators showed issues regarding the rotor dynamic stability, with the first critical bending speed being close to the rated speed. Field poles bent radially outwards at their ends, relaxation of the V-blocks was found and rim sagging from ID towards the OD affecting the braking performance. All units had major modifications on the rotors plus reinforcement on the thrust brackets during the initial years of operation to further improve the performance and had operated without experiencing critical rotor problems from 1985 for about 27 years.

Around 1988, water leakage issues were found on the stator windings. As result, all three units were rewound until 2003. The U2 was initially rewound with original spar Westinghouse windings in 2001 due to the significant amount of partial discharge repairs. OEM poles were re-insulated as well.

The units 1 and 3 generators were rewound (new stator windings and poles re-insulation) in 2002 by Voith with the same rating of 390 MVA at PF 0.90. with class F stator winding and temperature rise limit of 75°C. The overrated capacity was kept the same, with the temperature rise for the poles limited to 100°C. Refer to Figure 3-14 for name plate data for the rewound generators.

Stantec

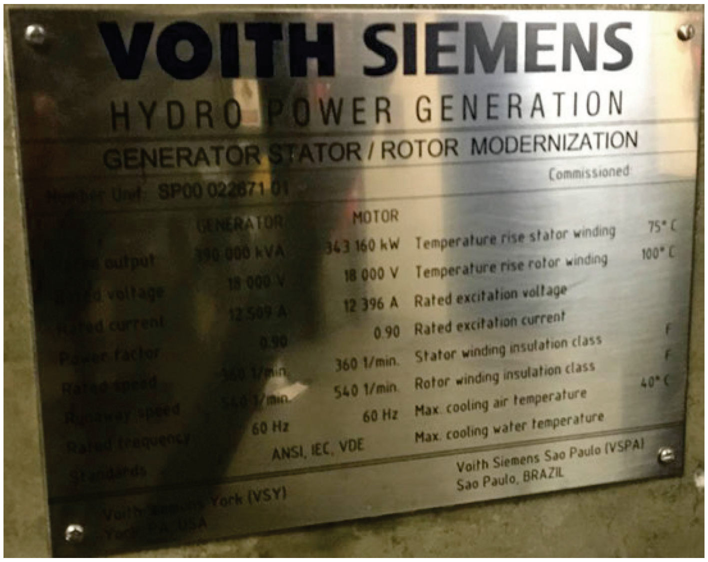


Figure 3-14. Nameplate Data for Rewound Generators

In 2009, Voith Hydro advised PG&E to inspect all the Westinghouse rotors for potential cracks in the pole fixation. Detailed investigations with FEA fatigue assessment and material sampling were performed. In 2011, the inspections of U2 rotor rim dovetails revealed cracks in the rim lamination material. PG&E conducted extensive analysis with support of consultant engineering team involving FEA modeling, crack assessment and material testing that allowed for a planned repair outage while new rotors being designed, manufactured and installed with limited number of start-stop cycles to minimize the risk.

During the crack investigations (2011-2012), U2 had the least amount of cracking and was repaired by grinding and polishing the cracked region. U1 and U3 was too critical to repair. PG&E and Voith resolved by grinding, polishing, and indexing the poles by rotating them in counterclockwise direction to the next adjacent dovetail location. This move unloaded the rim cracked dovetail radius and placed in the interpolar space. Based on 2014 new inspections, U3 was placed as a spare rotor and planned to be scrapped in 2023. Those efforts supported PG&E on mitigating the rotor rim issues and avoided a long-forced outage while new rotors were manufactured.

The complete generator rotors were replaced in 2015 provided by Alstom for all three units, with new spider, new rim and new poles class F insulation and temperature rise limited to 80°C (Figure 3-15). The rated power was then revised to 448 MVA in generator mode at PF 0.90 and kept the same for motor operation of 347.2 MW. It should be noted that Alstom was the OEM during the design and commissioning of all three Helms rotors, and few years after became GE which assumed Alstom’s responsibilities as OEM.

Figure 3-15. Nameplate Data – New Rotors

More recently in 2020, U2 was rewound by Voith, with an improved stator winding design based on the previous rewound experiences from U1 and U3 in 2002. The rated output was increased to 450 MVA at PF 0.90 in generator mode and kept the same for motor operation to 347.2 MW (Figure 3-16).

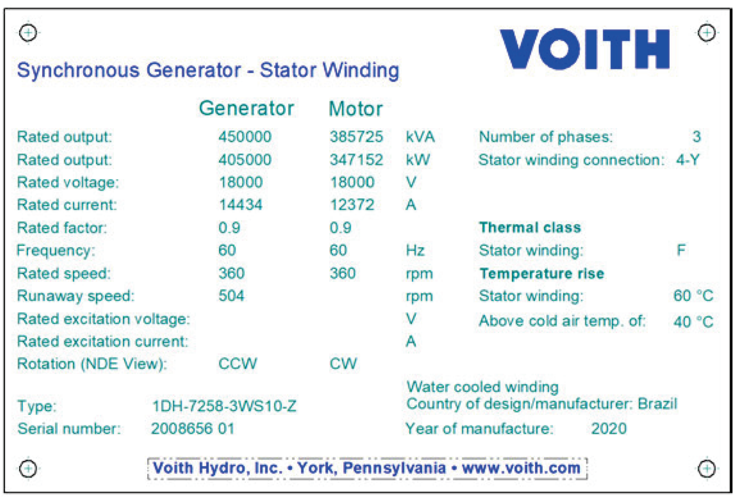


Figure 3-16. Nameplate Data – U2 Stator

A summary of the status of motor-generators components is presented in Table 3-9 below.

Table 3-9. Summary of Motor - Generator Components

	Units 1 & 3	Unit 2
Power Rating	390 MVA (Nominal) 448.5 MVA (Maximum)	450 MVA (Nominal)
Stator winding	Voith Siemens (Re-wound 2002)	Voith Hydro (Re-wound 2018)
Stator winding (circuit rings)	OEM Westinghouse (1984) Re-insulated	OEM Westinghouse (1984) Re-insulated
Stator core	OEM Westinghouse (1984)	OEM Westinghouse (1984)
Rotor	Alstom (Replaced 2015)	Alstom (Replaced 2015)
Pure water system	OEM Westinghouse (1984)	OEM Westinghouse (1984)

3.2.1 Uprate Potential Studies

With the increased demand on renewable energy with solar and wind sources in recent years, PG&E initiated in 2022 preliminary uprate studies for the existing generators to define the maximum capacity of the current fleet while maximizing a reasonable capital investment and scheduling constraints, looking for a capacity increase amendment. Voith and GE were invited to provide preliminary uprate studies on the main generator components as summarized in Table 3-10:

Table 3-10. Preliminary Studies of Generator Components

	Voith	Alstom
A. Electromagnetic and ventilation	X	X
B. The stator with core, frame and winding;	X	
C. The rotor with spider, rotor rim, poles;		X
D. Shaft and shaft couplings	X	X
E. Thrust bearing	X	
F. Brake system and brake ring	X	
G. Generator foundations	X	

Table 3-11 presents the executive summary of the uprate studies.

Table 3-11. Summary of Limits for motor-generator Components

	Existing Units	Uprating Limit	Remarks:
Stator winding	Unit 2 -Voith (Re-wound 2018)	520 MVA	Limited by bars hollow conductors section
	Units 1 & 3 -Voith (Re-wound 2002)	481 MVA	(Necessary to confirm pure water system capacity)
Stator winding (circuit rings)	OEM Westinghouse (1984) Re-insulated	To be defined	Limited by magnetic induction (Existing temperatures have to be measured)
Stator core	OEM Westinghouse (1984)	N.A.	Limited by the existing core condition
Rotor	Alstom (Replaced 2015)	493 MVA	Limited by field winding temperature, to Class B (Existing temperatures have to be measured)
Pure water	OEM Westinghouse (1984)	To be defined	Necessary to confirm pure water system capacity

The uprate studies for the main components were reviewed by Stantec team. The FMEA report regarding the design concerns on the new rotors provided by Alstom was also revised and a detailed engineering analysis is provided in the following sections.

3.2.2 Electromagnetic and Ventilation Design

Estimate of Current Equipment Condition:	Moderate Condition (Modification and Replacement Proposed)
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

Voith uprate studies were focused on the motor-generator stators. The stator windings on U1 and U3 from the rewind performed in 2002 are current rated to 390 MVA. Electrically, those machines could reach up to 481 MVA with stator coil cooling water temperature rise limited to 30 K. This results in a hot water absolute maximum temperature limited to 70°C, considering stator coil water inlet temperature of 40°C.

The stator winding currently installed in units U1 and U3 has less copper on its stator bars and does not have the same electrical and hydraulic connections that were improved in unit 2. The vibration levels are larger in these units compared to unit 2. These higher vibration levels would likely severely stress the water boxes on the winding affecting life and possibly resulting in water leakage and potential short-circuit risk.

During the recent U2 rewind in 2020, several issues were found with the original OEM stator core presenting multiple hot spots and extensive repair works. Therefore, Voith recommended keeping the rated output of 390 MVA for continuous operation and overrated up to 448.5 MVA (+15 percent) for the U1 and U3.

The stator windings on U2 were redesigned and optimized with the rewind in 2020. The stator bars copper cross section increased by 25 percent, increasing further the rated capacity on this unit current at 450 MVA. The Voith uprate study indicated that existing stator winding could go up to 520 MVA, restricting the stator coil cooling hot water maximum absolute temperature to 70 degrees centigrade (°C) for a cold-water inlet temperature of 40°C. The calculated cooling water velocity inside the hollow copper conductors was [redacted] nearing the limit of [redacted]

Operating the unit at a higher power output will increase the temperatures and potentially the vibration levels. This would lead to further degradation of the interlamination insulation between the thin stator laminations in the existing stator core. Eventually this degradation will result in excessive hot spots in the core that will affect the life of the stator winding.

Voith expected there would be considerable risk when operating the existing stator core at higher output based on the condition of the core as it was left during the 2020 rewind.

According to the Voith uprate study, the electromagnetic and ventilation calculations show that with the option of a new stator core, the new stator winding based on U2 can be further improved with a new water hydraulic circuit, resulting in a new uprate capacity of 570 MVA at PF 0.90 for the stator core and winding itself. Note that this maximum output is limited by the turbine hydraulic capabilities and by the other components individual limitations described in this document.

The feedback from PG&E is that the new stator windings on U2 have very good performance in terms of temperature on the stator bars and vibration levels. Therefore, this design shall be used as a baseline for a new stator winding for further improvements.

Considering the current limitations and remaining life expectancy for U1 and U3, the recommended approach is to replace both with new stator core and stator windings, at least as minimum scope. U2 had its stator core recently repaired and rewound, has a potential capacity to be uprated to 520 MVA with additional risk mitigation measures to ensure reliable and smooth operation.

The OEM rotor rim design presented cracks in the region of the pole fixation and in the rotor spider. In 2015, all three units received new rotors (rotor spider, rim, poles, and brake rings) manufactured by Alstom with current rated capacity of 448.5 MVA. Following a similar uprated study approach, GE provided an analysis of the new rotors to define the maximum output.

Although the Voith analysis did not include the new rotors installed at Helms, Voith did review the rotor data provided by PG&E. Voith noted that the new rotor poles have a class B operating temperature rise (80K) and a class F insulation temperature rise (100K). The new rotor poles uprate estimated limit was calculated to 493 MVA @ PF 0.9 to keep at class B operating temperature rating limit.

Heat run tests were performed by Alstom in 2016 after the commissioning period of U2 to verify the pole temperatures. Temperature labels were installed at the field winding accessible location to record the temperature rise. Measurements in Feb/2016 (cold season) shows temperature above 79°C. New measurements were collected in Sept/2016 (warm season) and the calibrated calculations showed values with temperature above 121°C. Measurements and calculations provided by Alstom shows that at current rated condition of 448.5 MVA, the poles are already reaching or exceeding the Class B limits.

The current densities are considered adequate. However, it’s not possible to further increase the output power to the Alstom initial targeted value of 516 MVA without modifications or improvements on the poles, limited by the temperature rise on the field windings. Refer to Table 3-12 below for the summary of results.

Table 3-12. Current Densities at various power outputs

CHARACTERISTIC	MEASURED AT 448.5 MVA, 0.9 P.F.	CALCULATED AT 448.5 MVA, 0.9 P.F.	CALCULATED AT 516 MVA, 0.9 P.F.
Rotor excitation current	U1 2547 A U2 2540 A U3 2547 A	2545 A	2761 A
Current density	2.28 A/mm² and 2.77 A/mm²	2.28 A/mm² and 2.77 A/mm²	2.47 A/mm² and 3.00 A/mm²
Rotor winding average temperature rise (temp. if 40 C cold air)	U1: 65.6 K (105.6 C) U2: 67.5 K (107.5 C) U3: 75.7 K (115.7 C)	U1: 65.6 K (105.6 C) U2: 67.5 K (107.5 C) U3: 75.7 K (115.7 C) (above are calibrated)	U1: 81 K (121 C) U2: 83 K (123 C) U3: 93 K (132 C)
Maximum rotor copper temperature rise (temp. if 40 C cold air)	-	U1: 80 K (120 C) U2: 81 K (122 C) U3: 92 K (132 C)	U1: 98 K (138 C) U2: 100 K (140 C) U3: 113 K (153 C)

Pre-design activities include:

- Review and harmonize with the plant level the target output for the motor-generator uprates.
- Perform a detailed electromagnetic study to confirm dimensions for the new components like stator bars, circuit ring, water cooling hydraulic circuit, stator core.
- Perform resonance check with the natural frequencies and electromagnetic excitation frequency to ensure no harmful vibration.
- Perform a ventilation analysis to review the air flow, with special attention to the poles and at the stator circuit ring and terminal regions. Perform measurement of cooling air flow. Identify and propose potential improvements in the local temperature at those regions.
- Conduct heat run and vibration measurements at the site with the unit operating at maximum power and PF 0.90 to calibrate the calculation models. The measurement shall be preferably performed on U2 which is equipped with the most updated stator windings and new poles. Collect and compare operational data with the current conditions and focus on the temperature of the stator windings and poles.
- Confirm excitation voltage and current.

3.2.3 Stator Windings

Estimate of Current Equipment Condition:	Good/Moderate Condition (Replacement Proposed)
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

The stator windings on U1 and U3 has less copper and is at rated capacity of 404 MW. The new stator winding design present in U2 has significant design enhancements over the OEM design. However, the main limiting factor for all units is the OEM stator core hot spot issues. Refer for more detailed description in the Electro-Magnetic and Ventilation Design section.

Therefore, to reach the expected uprate capacity of 460 MW Stantec recommends replacing all three unit's stator windings based on the similar design of U2.

Pre-design activities include:

- Create a 3D model with the new complete stator winding with water couplings, bar overhangs, circuit ring, terminals, etc. to verify the assembly space in this area which is considered critical in the current design and should be improved. Special attention to ensure that dielectric distances are suitable for the 18 kV-rated voltage and the influence of the high elevation altitude in the electrical tests during installation and commissioning.
  Current circuit ring design has a polygonal shape which reduces the available space at the corners region to allow the assembly for the other components (i.e., surge rings and supports). The new design shall consider circular-shape circuit rings to improve the available space, dielectric and magnetic distances, air flow circulation, etc.
- Perform an FEA with stress and fatigue assessment with the new bars overhang and water couplings. Include a vibration analysis considering the new electromagnetic loading.
- Perform induction heating FEA calculation for the stator windings considering the increased currents for the targeted uprate to verify and confirm the materials in the stator main and neutral terminals surrounding area should receive a shield protection to avoid overheating.
- Review the cooling water hydraulic circuit with the new proposed design by Voith and confirm the new layout for the water distribution manifold around the stator.
- Confirm in advance the critical components lead time for the stator bars and water couplings and incorporate in the master scheduling. Review the supply chain scenarios, identify potential risks, and evaluate necessary actions to mitigate the risks.

3.2.4 Stator Core

Estimate of Current Equipment Condition:	Poor Condition (Replacement Proposed)
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

Due to the hot spot issues on the existing stator core, it's highly recommended to install new stator cores for all three units. Voith reviewed the OEM core fixation system stress calculations, consisting of keybars welded on the stator frame and not allowing for thermal expansion. With the power increase, the torque on those welds results in stresses over the allowable stress limits. See Figure 3-17 below for over-stressed areas.

[redacted]

Figure 3-17. Key Bars Welded on Stator Frame.

The OEM pressure fingers were assembled “loose” in the lower and upper pressure plates, typical design from this vintage. With this design, there is less or no ability to transfer the bending moment from the pressure plate to the fingers effectively, and issues to keep the pressure at the core teeth region, resulting in local lamination vibrations and hot stops.

During the U2 stator rewound, it was observed a 3 mm shimming at top and bottom parcels of the core, probably an attempt in the early years of operation to increase the pressure at the core teeth region. Voith believed that part of the U2 stator core hot spots issue is related to the pressure distribution at this region which seems not adequate.

Therefore, Voith recommended replacing the existing stator core clamping system with the modern design consisting of dovetail keybars to allow for free thermal expansion plus the clamping system with welded pressure fingers to the pressure plates and clamping studs with Belleville washers to ensure the pressure on the core is maintained (Figure 3-18).

[redacted]

Figure 3-18. Stator Core Clamping System

The core buckling analysis provided by Voith shows a safety factor of 2.8 and fulfills the minimum required value of 2.0.

Pre-design activities include:

- In the case of a refurbishment of existing U1 and U3 (not recommended), perform a detailed inspections on the existing stator cores, looking for hot spots, NDE welds on the key bars and laser dimensional survey (level and roundness).
- Confirm the number of slots for the new stator core solution provided by Voith and the material properties to improve performance with less losses due to less magnetic field strength.
- Explore air gap improvements with a new stator core.
- With new stator core fixation and clamping system, the mechanical natural frequency of stator core and frame may change. Therefore, a sensitivity analysis with FEA shall be performed to cross check with the excitation frequencies and ensure no resonance issues.
- Perform natural frequency checks on the new stator core clamping to avoid vibrations in operation. Determine the required amount of insulation bushing supports along the core length.
- Provide a stacking and powerhouse space utilization plan, identifying necessary lifting devices, working platforms and logistics plan.

3.2.5 Stator Frame

Estimate of Current Equipment Condition:	Good/Moderate Condition (Modification or Replacement Proposed)
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

The existing stator frame OEM design did not reveal any significant concern for the uprate target and seems possible to be re-used.

Pre-design activities include:

- Confirm the new required clamping force and reaction force against the stator frame top plate.
- Confirm the available space between the new core OD and the stator frame ID. Identify necessary modifications in the current stator frame.
- Detailed FEA and fatigue calculations shall be performed to evaluate the remaining life and suitability for re-use the existing frame or for a new frame.
- Get an estimated cost for the existing frame modifications and NDE inspections to be reused and compare with the cost of a new stator frame.
- Provide a comparison analysis with cost and scheduling improvement considering a new stator frame.
- Confirm the lead time to supply the new frame, required logistics plan to get into the powerhouse.
- Verify erection sequence and powerhouse occupation plan considering preferred stacking method with continuous stacking one piece core instead of split core.

Recent experiences with modernization projects reveal a significant benefit to justify new stator frames due to the increased costs for NDE inspections and modifications at site to reuse the existing ones. Therefore, the final decision should consider scheduling improvements with new stator frame and an economic analysis with new versus a rehab stator frame.

3.2.6 Stator Foundations

Estimate of Current Equipment Condition:	Good/Moderate Condition (Refurbishment and Modification Proposed)
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

Voith provided a review on the existing stator soleplates and analytical calculations show the existing components are suitable to be reused. However, shear stresses on the existing dowels exceeds the allowable stress limits and new dowels will be required for the target uprate power.

Pre-design activities include:

- Confirm material properties of the existing dowels.
- Confirm size and quantities of the new dowels.

- Provide detailed foundation load calculations for the stator soleplates and for the anchor bolts with the mod or new stator frame. Review with civil engineering is recommended.
- Perform a detailed laser measurement to confirm the existing soleplates level.
- Provide procedure for potential soleplates level, stator roundness and concentricity corrections.
- Provide detailed procedure for the stator soleplates re-doweling process. The drilling may have limited access and would require concrete excavation.

3.2.7 Rotor Pole Winding

Estimate of Current Equipment Condition:	**Moderate/Poor Condition (Modification or Replacement Proposed)**
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

The OEM Westinghouse poles were furnished with flat/straight field windings and V-blocks in the inter-polar space. The main purpose of the V-blocks was to provide lateral support for the field coils against the centrifugal loads between two adjacent poles. Additionally, air baffles were included to restrict the airflow between the poles, imposing higher air speeds close to the coil fins, increasing the heat transfer coefficient and providing good ventilation on the field windings. Refer to Figures 3-19, 3-20, 3-21, and 3-22 for section drawings.

[redacted]

Figure 3-19. OEM Westinghouse Rotor Poles Layout, with Flat Field Coils and V-Blocks Coil Supports

[redacted]

Figure 3-20. OEM Pole Coil Bracing V-Blocks Side View

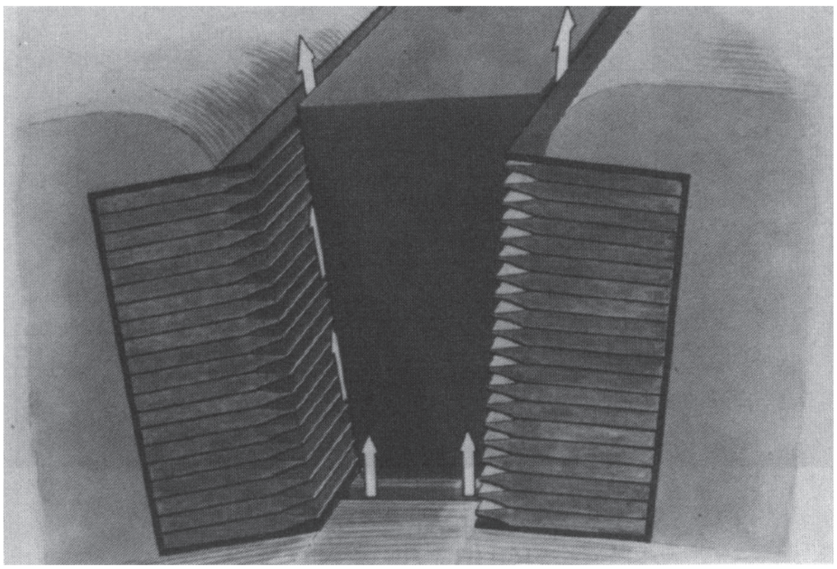


Figure 3-21. OEM Interpolar Space Baffles to Increase Air Speed and Heat Transfer at the Pole Coils

[redacted]

Figure 3-22. OEM Pole Coil Bracing V-blocks Top View

During the re-design of the new poles, Alstom removed the V-blocks between the poles by designing a chevron/curved/wound coils to withstand the centrifugal load component in tangential direction with the goal to facilitate the pole maintenance, with the rotor assembled in the pit. Also, removed the original OEM interpolar space baffles (Figure 3-23).

[redacted]

Figure 3-23. New Poles Provided by Alstom with Chevron/Curved Coils Without V-Blocks Supports

The coils were assembled directly against the pole body and fixed by means of insulation wedges/shims around the length between the pole coil and pole body (Figure 3-24).

[redacted]

Figure 3-24. Coil Assembly

During the first-year inspection on U2 new poles, gap issues were reported between the coil turns and pole body. Also, Nomex insulation migration was observed (Figures 3-25 and 3-26).

Note: U2 Pole 7, 13, 14, 15 19 1st in the year inspection

Figure 3-25. Very Large Gap Between the Last Pole Coil Turns, at Pole Endplate Head

Note: U2 poles 5, 8 and 18

Figure 3-26. Nomex Paper Migration Between Insulation Frame and Pole Endplate Head Top

Both issues were remediated by Alstom by adding a wedging system to compress the coils against the pole body at the top endplate only (Figure 3-27). This solution was already implemented in U2, and U1 and U3 are scheduled for 2024. Further inspections are required to verify and confirm the effectiveness of this solution.

Figure 3-27. Wedging System

The lack of the V-blocks to properly support the coils may be related to excessive deformations of the pole coils caused by high centrifugal loads, resulting in large deflections, lateral coil bending/bowing plus additional twist around the pole shoe. Those effects could explain the observed gaps between pole coils and pole end plate heads.

The lack of pressure/looseness at this region combined with the thermal cycles during the operation may result in relative movement between the pole coils and ground wall insulation which could explain the Nomex paper migration. On top of all, to keep overall tolerances with a more complex geometry, increased manufacturing challenges are expected.

There is a potential impact in the ventilation of the pole coils as already mentioned at the beginning of this section. The lack of the interpolar spacer per OEM Westinghouse design may lead to lower air speeds and less heat transfer capability, resulting in comparably higher field coil operating temperatures.

According to GE, at the output of 448.5 MVA PF0.9. the average temperature on the pole windings is 80K above cold air at 40°C and meets the class B temperature rise.

GE conducted heat run measurements in 2016 calibrated the electric and ventilation calculations, refer to section 3.3.1 (Electromagnetic and Ventilation data). For the uprated power of 516 MVA at PF 0.90, the current pole windings would reach temperature between 138 and 153°C, which far exceeds the class B recommended temperature rise (Figure 3-28).

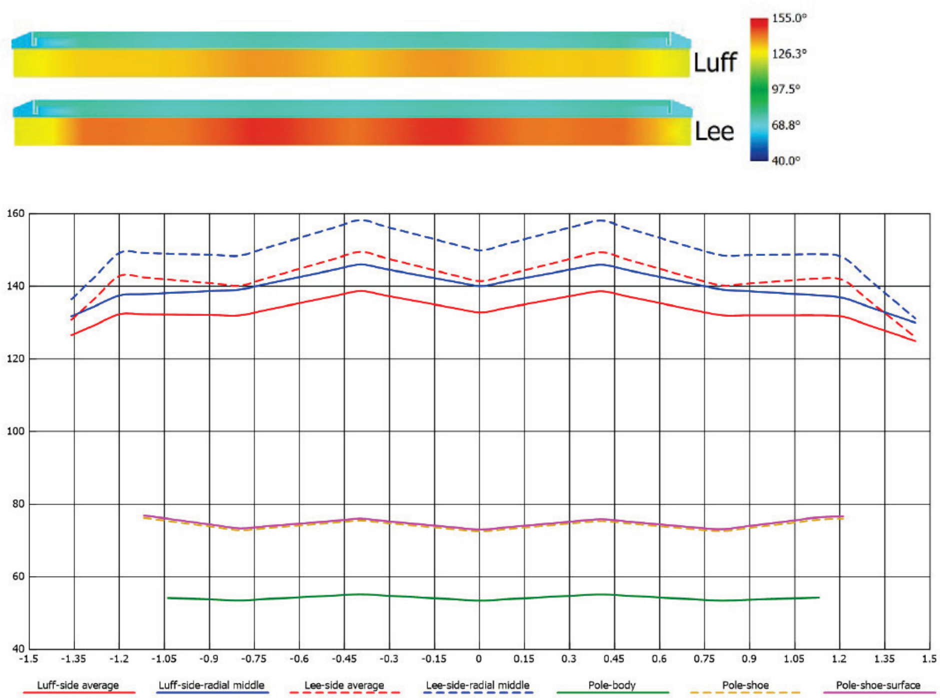


Figure 3-28. Temperature Distribution on Each Side of Pole Coil at 516 MVA, PF 0.90 with 40°C Cold Air

Note the significant temperature difference at the same pole (~25°C, with the middle being warmer than the top and bottom planes). Also, there is a difference between leading (Luff) and trailing (Lee) coil sides regarding the rotation counterclockwise direction in generator mode with higher temperatures in the trailing side (side away from the facing wind). To be confirmed the rim ventilation ducts distribution on each side of the poles and see if additional effect on the temperature distribution.

Higher temperatures lead to premature aging of the insulation and varnishing materials, and higher fatigue stress gradients on the coils and copper connections. GE's conclusion is that the current poles cannot operate at 516 MVA with PF 0.90.

Therefore, Stantec emphasizes that it's extremely important to understand the root cause of the existing issues to properly address the current issues and consider actions to further reduce and mitigate technical risks.

Pre-design activities include:

- Request GE for references where the current design with chevron/curved coils in replacement of the V-blocks was successfully used in machines with similar power, size and speed as Helms.
- Ventilation study to compare the airflow and heat transfer on the pole coils considering interpolar space baffles per OEM Westinghouse design and without per current Alstom design.
- Heat run measurements with pressure and air flow measurements. Confirm differences between units and identify reasons for the temperature differences on the poles at 448.5 MVA and PF 0.9.
- Perform a ventilation analysis with potential increased airflow and cooling water, provide suggestions on how to improve pole winding temperatures and define the maximum uprate capacity for the existing poles. Investigate additional ventilation ducts at the middle of the new core stacking layout to increase the air flow at the middle of the poles. Additional air baffles to throttle the air flow distribution between top/bottom to the middle of the poles to improve the temperature distribution in the coils.
- Perform a detailed FEA and fatigue analysis to check stresses and deformation on the pole endplates, pole coils, pole connections and verify the effect of the V-block absence, considering the centrifugal loads plus the thermal cycle effects. Check maximum bowing deflection on the coils and allowable stress on the copper. Check maximum relative movements between coil and ground wall insulation, thermal expansion of coil against the pole body in longitudinal direction, contact conditions against pole body at the pole shoe.
- Perform and record detailed inspections on the pole coils, looking for signs of discoloration, relative movements and lateral/tangential bowing and twist of the turns. Use as baseline for future inspections.
- Locate and record the gaps between the coils as reported issue. Check contact and supporting conditions and against the pole body. Ensure the repair method by wedging/shimming was effective and issue is resolved. Perform electrical tests to verify inter-turn insulation condition due to the local movements. Check magnetic flux.
- Prepare a detailed OMI (Operation and Maintenance Instructions) for the poles to establish a baseline and close monitor the poles to mitigate the risks associated with the current issues (gap between coils, Nomex paper migration, high temperature and coil turn bowing).

3.2.8 Damper Windings

Estimate of Current Equipment Condition:	Moderate Condition (Replacement Proposed)
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

The OEM Westinghouse poles had a symmetric damper winding with 5 damper bars. With the new poles, Alstom changed the design to 7 damper bars with asymmetric configuration to improve the TIF (telephone influence factor).

Based on the GE electrical assessment, the damper bar maximum allowable temperature rise is 143°C before the damper bars interfere with the pole end plates for the current output. However, considering the target output of 516 MVA, maximum expected temperature rises to reach is around 156°C for a $I2^2$ t of 20 seconds, already under the standard 40 seconds. Changes to the damper windings are required to allow for free thermal expansion. Refer to Figure 3-29 for damper windings configuration.

[redacted]

Figure 3-29. Damper Windings Configuration

Pre-design activities include:

- Calculate current distribution among damper bars and corresponding temperature rise.
- Perform FEA and fatigue stress and deformation assessment with focus on the damper bars, connections, and pole lamination, considering the expected thermal expansion.
- Propose modifications on how to improve the current design to allow thermal expansion without harmful effect to the lamination.

3.2.9 Rotor Pole Lamination and End Endplates

Estimate of Current Equipment Condition:	Moderate Condition (Modification or Replacement Proposed)
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

GE uprate study shows that the pole core dimensions are acceptable from the magnetic saturation standpoint with calculated flux densities under maximum permissible values.

At the time of the new poles design, Alstom provided FEA structural analysis reports for the pole end plate and for the laminations showing that stresses, deformations, and fatigue assessment are within acceptable limits.

The centrifugal loads usually represent the largest contribution factor in the pole stresses at rated and runaway conditions. The start-stop cycles between standstill and rated operation have highest impact in the fatigue life (Figure 3-30).

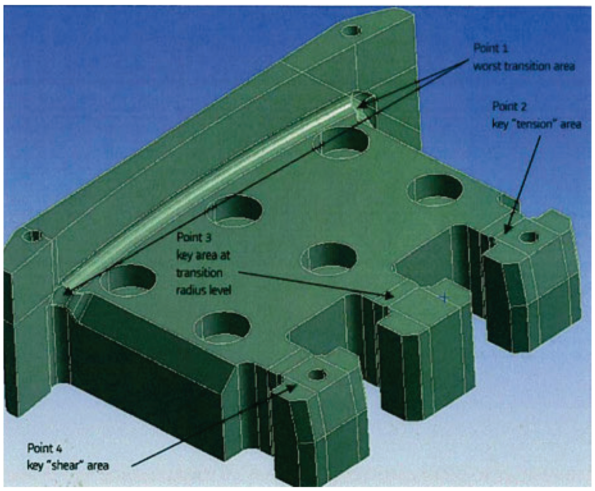


Figure 3-30. FEA Model of Pole End Plate and Laminations

The critical regions are Point 1 and Point 3 and a summary of the results are presented in Tables 3-13 and 3-14 below for the power output of 448.5 MVA at PF 0.90.

Table 3-13. Von-Mises Stresses at Pole End Plates

Table V Von Mises Stresses (MPa)

Location	Stress Category	Nominal operation	Contractual criteria	Maximum overspeed 540 RPM	Contractual criteria
1	P_L	42	**290**	92	**603**
	P_L+P_b	122	**290**	268	**603**
	P_L+P_b+Q+F	348	**Fatigue**	768	**Fatigue**
2	P_M	82	**193**	182	**402**
	P_M+P_b	104	**290**	228	**603**
3	P_L	92	**290**	203	**603**
	P_L+P_b	115	**290**	248	**603**
	P_L+P_b+Q+F	340	**Fatigue**	735	**Fatigue**
4	P_M	73	**193**	161	**402**
	P_M+P_b	102	**290**	224	**603**

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Table 3-14. Pole Endplate Static Strength Assessment

Table VII Fatigue Cumulative Damage

		Interest Point 1	Interest Point 3
Start-and-Stop cycles	Stress *amplitude* (S_a [MPa])	174	170
	Number of cycles (n)	55 000	55 000
	Allowable number of cycles (N)	127 265	154 380
	Damage factor (n / N)	0.43	0.36
Runaway cycles	Stress *amplitude* (S_a [MPa])	335	321
	Number of cycles (n)	100	100
	Allowable number of cycles (N)	5 431	6 921
	Damage factor (n / N)	0.018	0.014
	Cumulative damage factor (Σ n / N)	45 %	37 %

Pole Endplate Fatigue Assessment per ASME.

Based on those results, GE presented in the uprate study report the re-calculated stresses considering the torque increase of 15% due to the 516 MVA, concluding that the increase in the total equivalent stress is negligible (less than 1 MPa) for both components pole end plates and pole laminations.

It's important to note that the FEA models were simulated considering theoretical/ perfect ideal geometry and uniform loading conditions, with the focus on the stresses. The inspections and findings show that the reality is more complex, and the models were not able to explain the current issues on the Alstom poles as described in more details in pole winding section.

Pre-design activities include:

- OEM design shows the pole fixation with 2 dovetails versus 3 hammerheads in the new design which requires some effort since design and manufacture until installation to ensure uniform contact with the rotor rim.
- The absence of the V-blocks and the chevron/curved pole windings in the new design may have some negative contribution to the gap issues and Nomex paper migration found between the pole coils and pole endplates. The coils without V-blocks may have a larger lateral deformation, bowing in tangential direction and twisting around vertical axis, resulting in an uneven contact condition between the last turns of the coils at the pole shoe region.

Refer to Figure 3-31 for pole wedge configuration.

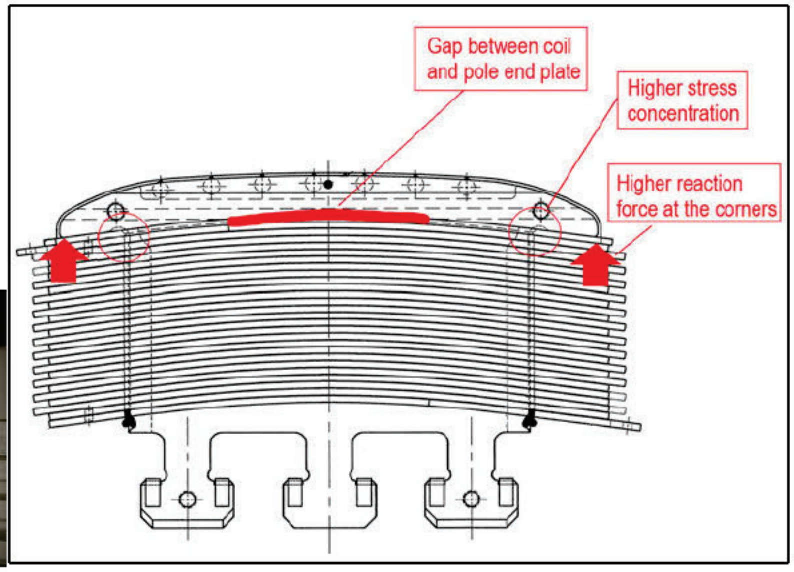

Figure 3-31. Pole Wedge Configuration

Pole fixation wedges in the OEM design were across the full length of the pole. In the new design, Alstom used short wedges mainly at the pole endplate thickness (Figure 3-32). For both cases, the poles are meant to be in contact in full length with the rim for centrifugal loads. There are concerns with the short wedges design, especially for motor-generators with loads in tangential direction. The torque introduces shear and a binary moment to the fixation, which may lead to additional torsional deformation on the pole body given the Helms long pole length of 2,766 mm.

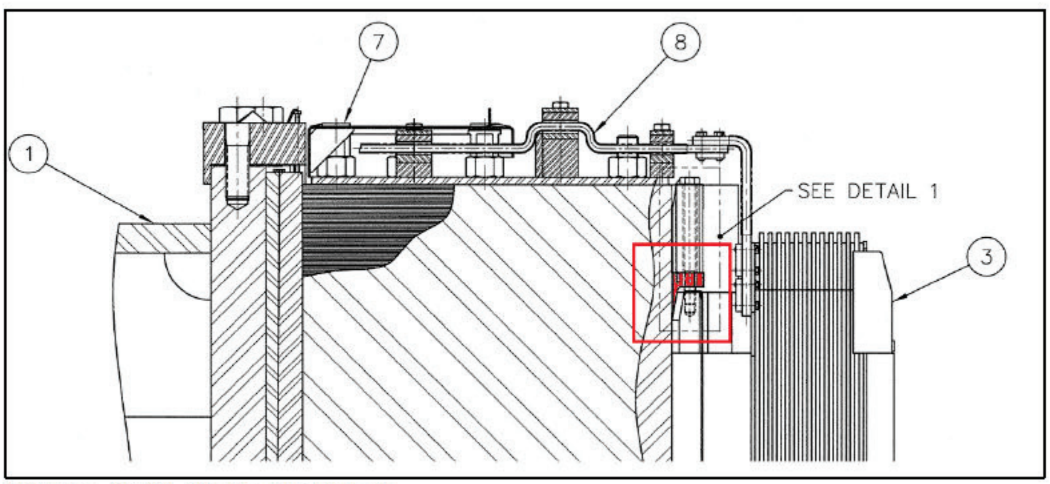

Figure 3-32. Pole Endplate

Pre-design activities include:

- Refine FEA model for the pole body lamination and end plates at the pole shoe region. Provide a 3D model, including the coils to better simulate the contact and load distribution to the pole body. Include the effect of the temperature gradient on the coils.

- Perform a sensitive analysis including the effect of the reported gaps between last turns of the coil at the pole end plate, check the effect in the stress levels.
- Check the relative movements between coil and end plates at the region with the Nomex paper migration issue.
- Analyze the effect of the short fixation wedge for the pole body and the influence on the coil deformations.
- Perform a dimensional inspection on the pole coils, looking for flatness and contact against the pole shoe.
- Perform a dimensional inspection on the pole fixation hammerheads, look for alignment and flatness among each contact surface on the pole side and in the rim side to ensure uniform contact.

3.2.10 Rotor Spider

Estimate of Current Equipment Condition:	Moderate Condition (Modification Proposed)
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

OEM Westinghouse rotor spider was designed with 6 radial arms to withstand the rim shrinkage loads plus the dead weight of the rim and poles. There were additional 6 head beams to transfer the torque and to provide additional tangential guidance for the rotor rim, keeping its roundness and concentricity. The total rim shrink between spider and rim was 0.102 inch (2.59 mm). Part of this shrink stored by a radial spring key of 0.078-inch (1.98-mm) deflection and the remaining deflection shared between spider and rim. Refer to Figure 3-33 for rotor rim keys configuration.

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[redacted]

Figure 3-33. Rotor Rim Keys Configuration

The new rotor spiders were completed by Alstom in 2015. The rotor spider consists of a welded structure with a central part with top and bottom flanges welded to a cylinder with reinforcement radial ribs in the inner side and 10 radial arms (Figure 3-34). There are 5 radial arms to transfer the rim shrinkage forces by the wedge carrier and to transfer the torque. The other 5 arms support the rim and poles dead weight in vertical direction. The flanges are coupled to the upper and lower generator shafts.

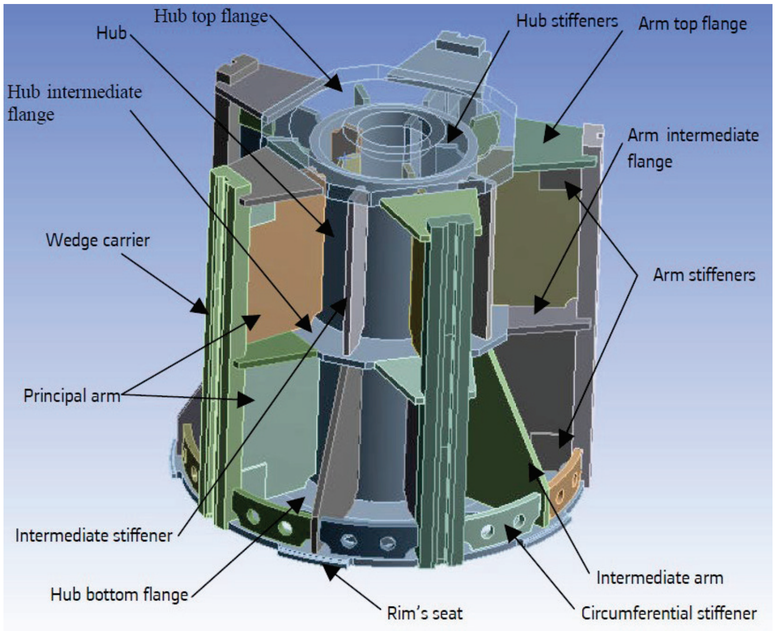


Figure 3-34. Rotor Spider

Per Alstom rotor spider FEA report, the new rim was designed to be shrunk on the rotor spider up to 110% of the rated speed, with an initial assembly shrink of 1.46 mm and a residual shrink value of 1.19 mm after slippage speed (340 to 440 rpm).

During the installation of the new rotors, S/N1 fell behind in schedule and PG&E decided to re-install the original U3 Westinghouse rotor at the pit operate until 2014 summer schedule. S/N1 has some differences in its construction as compared to S/N2 and S/N3.

S/N1 had quality issues during the stacking process. By design, the rim lamination geometry had cooling vents placed partially over the rim seats at first layers of lamination. Only about half of the circumferential lengths of the spider rim seats were withstanding the dead weight of the rim and poles. On S/N1, Alstom placed shims or spacers in the rim vents that were aligned with the rim seats for several inches above the bottom lamination.

The arrangement for the S/N2 and S/N3 rotors was different. Alstom relocated (indexed) the bottom layer of rim laminations from their original design positions so that no vent duct openings were directly over the spider rim seats for the first 24 lamination layers from the bottom, providing increased stiffness at the rim seats.

Uneven loading was discovered on the 5 rim seats after the support jacks were removed due to rim crowning issues. Feeler gauge measurements of the gap between the bottom lamination taken on S/N1 show unequal load sharing among the five rim support locations.

The new design of the spider arms allowed the rim sagging radially inwards at standstill due to the dead weight plus the shrinkage forces and outwards at the support locations at rated speed due to the centrifugal loads.

This concentrated loading on the rim seat edge is further intensified, particularly on S/N1 by the local slope/sagging at the bottom of rim on S/N1 (Figure 3-35).

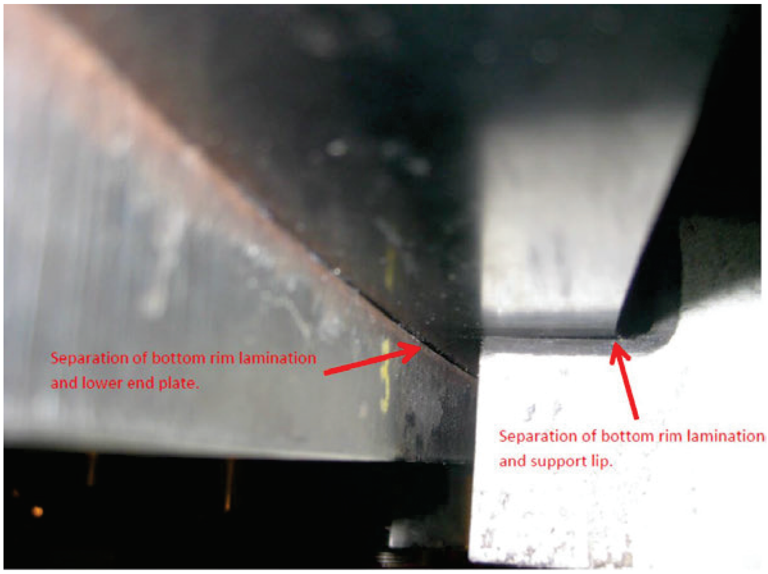


Figure 3-35. Rim Seat Edge

No lubricating paste was used at the rim seat interface. The relative movement between the bottom laminations and the rim seats during speed changes and loading condition (thermal expansion, magnetic pull, torque, etc.) can significant increase the friction forces leading to overload on the rim seats and result in fatigue damage mechanism.

Additionally, uneven rim displacements at the various support rim seats may affect rim roundness and concentricity with impact in the rotor balance.

The chord between two adjacent rim seats is around 2011 mm which is considered not ideal to ensure even deflections on the rim according to Stantec experience. This may cause additional sagging among the rim seats, resulting in concentrated loads at the tip of the lips, and resulting in higher stresses due to the additional bending moment effect.

The spider construction is made from thick rolled steel plates, heavy welds at the rim support locations where the steel plates are loaded through their thickness direction. This arrangement could potentially result in lamellar tearing. Current industry best practices show that for such load conditions, electroslag remelting, Z35 and preferably forged plates reduce this risk substantially. Alstom stated that the rolled steel plate material used has been successfully UT inspected but is unknown their successful experience with similar design in other projects.

Additional FEA was performed by both Alstom and PG&E (Exponent) to evaluate the S/N1 rotor and assess its suitability for service, considering the assembly quality issues. Considerations for completely restacking were considered however ruled out with FEA and material testing, claimed by Alstom that the rotor would last for many years and likely fulfil its design life expectancy.

The FEA analysis report with Alstom design for the new rotor spider shows that the stresses fulfill the static strength and fatigue assessment criteria in general. The main critical locations were identified at the wedge rim seat (ROI 22, Region of Interest), carrier (ROI 29) and bottom disc ventilation opening (ROI 28). The highest stresses occurred at standstill condition due to the initial rim shrinkage. The highest alternating stress amplitude for fatigue assessment occurs at start-stop condition.

During the uprate study review, GE noted that the region at the bottom of the wedge carrier was initially omitted and does not meet the fatigue requirements per ASME. GE argument the ASME conservative approach and safety factors, and alternatively presented an additional assessment based on FKM fatigue methodology. The assessment shows that allowable number of cycles decreased from 83 449 cycles at 448.5 MVA to 57 436 cycles at uprate power of 515.2 MVA which is according to the technical specification requirements considering three start-stop per day for 50 years and concluded that the rotor spider is suitable to be uprated without modification. Refer to Figures 3-36 and 32-37 for critical areas of the wedge carrier.

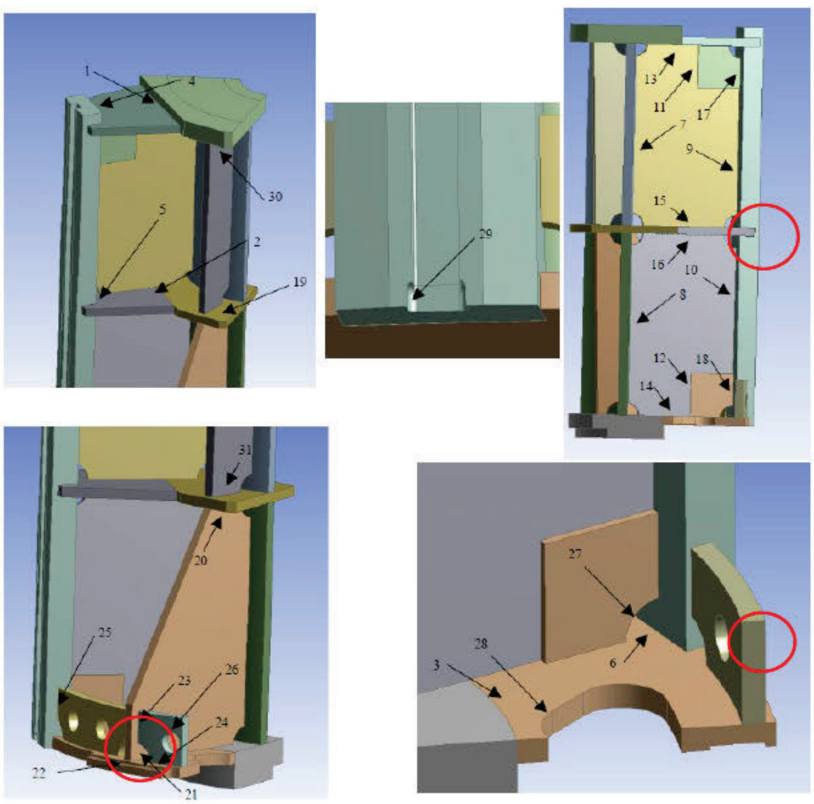
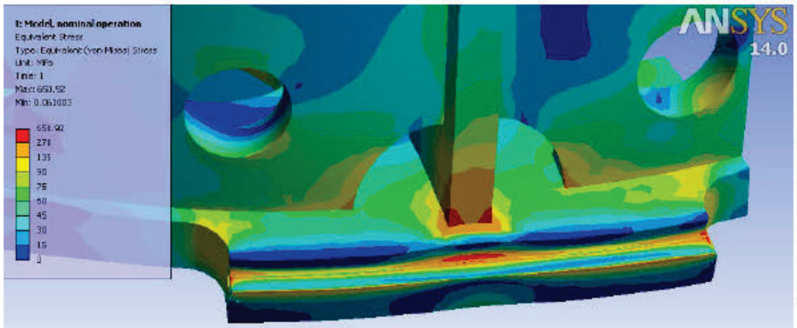


Figure 3-36. Critical Areas of the Wedge Carrier



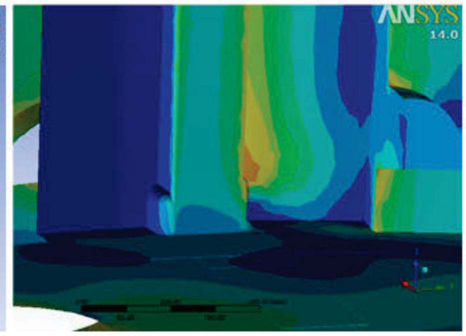


Figure 3-37. Stresses at Bottom of Wedge Carrier

Nevertheless, it's important to note that both Alstom and Exponent modeled the support of the rim and poles to be evenly distributed among the five rim seats and reality showed it was not the case. Simplifications were assumed to make FEA model practical for such a large and complex rotor construction, therefore results and conclusions were made and are affected by on those simplified modeling assumptions. Based on the inspections, observations and reported issues, Stantec recommends the following actions to be performed to confirm the rotor spider suitability for reuse under the uprate condition.

Pre-design activities include:

- Review the FEA models, refine the boundary conditions and create sub-models for better evaluation on the critical regions.
- Evaluate the impact of the uneven loading on the rim seats, considering 4 arms sharing the vertical loads and the rim slope with a line contact at the support lip edge and the impact on the stresses and fatigue assessment.
- Consider maximum friction coefficient due to the slope on the rim at the rim seats.
- Perform a sensitivity analysis to refine the FEA model and fatigue assessment.
- Include the effect of the shaft coupling radial constrain at top and bottom flanges, calculate the additional stresses and reaction forces due to the shrinkage relaxation from standstill to rated condition.
- Perform dynamics stress measurements with strain gauges to verify the load distribution among the spider arms during the operating conditions.
- Check the contacts between the rim and spider rim seats using feeler gauges to ensure full contact and provide a detailed report with findings.
- Perform laser level checks on the arms at standstill condition to ensure they are even loaded with uniform sagging.
- Confirm procedure on how to lubricate the rim seats.

- Prepare a detailed OMI inspection procedure, with visual inspection and UT inspection method using dual header scanners. Check the preload on the rim studs, locking of rim wedges and relative movements.
- Prepare a detailed mitigation plan including potential design modifications and reinforcements on the existing spider at the critical locations in the case cracks would be developed along the remaining life of the component.

3.2.11 Rotor Rim

Estimate of Current Equipment Condition:	Moderate Condition (Refurbishment or Modification Proposed)
Existing Capacity:	≥ 460 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

During balance trials, after S/N1 installation into Unit 3, a noticeable change was observed following 100% Load Rejection. Prior to 100% load rejection, U3 had operated at less than 10 mils vibration across each bearing proximity probe for the full range of operating conditions. Following the 100% load rejection an increase in vibration was observed, primarily at the main guide bearings but also noticeable at the auxiliary guide bearings, which required the installation of a substantial additional balancing weights.

The issues previously described with the spider rim seats may have influenced such behavior and contributed to an uneven rotor rim deformation at load rejection. Additional factors may also have influenced the rim uneven expansion like the shrinkage residual value, clearance holes for the rim studs, actual floating speed, chords between arms, number of guided supports to keep rim roundness, air gap, magnetic pull due to eccentricity between rotor and stator, etc.

S/N2 was balanced within specification at main and upper guide.

Pre-design activities include:

- Review the rim shrinkage calculation and ensure floating speed safety margin above rated speed.
- Perform FEA ovalisation calculation to confirm the rim stiffness on keeping the roundness and concentricity considering the maximum air gap eccentricity between rotor and stator and the magnetic pull.
- Perform laser measurements at standstill. Check rim leveling at the bottom. Check concentricity at top, middle and bottom planes, and verticality.
- Check flatness and alignment on the pole fixation slots to ensure good contact conditions with the poles and even loaded hammerheads.

- Perform rim radial deformation dynamic measurements at various load conditions to confirm floating speed with proximity probes and air gap sensors, and load distribution with strain gauges at rotor spider.

3.2.12 Brake and Brake Ring

Estimate of Current Equipment Condition:	Poor Condition (Replacement Proposed)
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

The U2 (SN 2) rotor was inspected in 2020 by GE (Alstom) and was found to have heat stress cracking on the brake segments, some loose retaining bolts for the segments. These conditions had been monitored closely by PG&E for the past years. GE repaired the brake segment bolt fixation once again, only U2 has been completed. U1 and U3 are expected to be complete in 2024, still under warranty.

It should be noted that multiple times over the previous years, brake segments have become loose and slightly dropped creating a potential risk. This is caused by the quality of installation of the keepers and the excessive clearance allowing the bolt head to rotate past the keeper. Just prior to GE's arrival, U3 had a brake segment drop over 1/8". It is only heard on shutdown when the brakes are applied, and the movement is heard as a loud cyclic thump.

U2 S/N2 was tested with brakes applied at 30 rpm and inspected multiple times. The design was modified until loose brake segments were no longer discovered. Subsequent inspections have resulted in success and confidence in the design. S/N1 and S/N3 both have the same fastener design as S/N2.

Pre-design activities include:

- Confirm the hydraulic remanent torque and time during the braking operation.
- Review braking calculation and application speed and confirm minimum thickness allowance.
- Measure brake ring temperature during the braking operation.
- Review the new brake ring design and the fixation system as built with all improvements to allow proper thermal expansion.
- Perform an FEA analysis to simulate the heat transfer, thermal expansion, and stresses on the brake segments.
- Review the design of the OEM brake jacks and brake shoes.
- Verify the influence of the rotor rim deformation issues on the brake segment issues.
- Check the brake segments leveling in radial and tangential direction at standstill.
- Verify the possibility for electric braking assisted operation.

3.2.13 Generator Shaft and Couplings

Estimate of Current Equipment Condition:	Good / Moderate Condition (Refurbishment and Modification Proposed)
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

The Voith uprate study shows that the calculated analytical torsional stresses are higher than usual 50MPA allowable stresses, however von mises stresses are within allowable limits.

Pre-design activities include:

- Perform FEA for detailed analysis in the critical regions including the actual geometry for proper stress concentration and fatigue assessment.
- Include in the FE model the shrinkage reaction forces actuating on the coupling hardware.
- Review calculation of coupling hardware.
- Perform NDE inspections with focus in the shaft critical areas determined by the FEA results.
- Material samples to be collected to confirm chemical and hardness properties.
- Perform MT/UT inspection in the existing shaft at critical locations.
- Perform dimensional inspections, shaft runouts and verticality/plumb.
- Refurbishment may be required to get runouts in tolerance. At this point a re-shaping may be beneficial to reset fatigue life.
- Review and propose a method to replace existing hardware, whether using eccentric bushing solution or a drilling template to ensure proper fittings.

3.2.14 Rotor Dynamics

U3 was commissioned with a reinforced upper bracket and the original rotor in 2014 rather than the new S/N1 rotor due to scheduling delays caused by the rotor rim stacking quality issues. S/N1 was completed during the summer of 2014 and then commissioned in May 2015. U3 S/N1 was also balanced within specification during startup and commissioning.

It was reported that the run with the original rotor and stiffened bracket showed positive rotor dynamic response in comparison to the original rotor without the stiffened upper bracket.

Also, it was reported that vibration response is comparatively better than the Westinghouse machines on all new rotors, likely due to the upper bracket stiffening that was performed as well as the increase in thickness of the spider top coupling flange.

Pre-design activities include:

- Perform an FEA optimization study to modify the upper bracket assembly position under the pony motor in order to reduce the distance to the generator magnetic center line and align the bearing centerline with the arms support on the concrete foundation. See sketch provided by GE and mentioned in Voith uprate study report.

Refer to Figure 3-38 for recommended modification to the upper bracket assembly.

[redacted]

Figure 3-38. Proposed Modification to Upper Bracket Assembly

- Confirm with PG&E if any concerns regarding the accessibility and maintenance of bearings with this layout.
- Optimize coupling stiffness to the existing rotor spider considering a new upper stub shaft.
- Review bearing stiffness values refined and confirmed by FEA.
- Review the shaft dynamics, considering updated calculations.
- Integrate and harmonize the potential modifications with the slip rings, excitation leads, pony motor and civil structure.
- Provide installation measures on how to improve the tolerances for the new stator roundness and concentricity to the existing rotor, the shaft line alignment, runouts, and verticality to achieve best air gap quality to reduce the magnetic pull effect.
- Review current vibration data and balancing procedure and provide recommendations to improve overall unit vibration.

3.2.15 Upper Bracket

Estimate of Current Equipment Condition:	Poor Condition (Replacement Proposed)
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

The upper bracket has been reinforced by GE to improve the shaft support and increase safety margin against the critical speed (Figure 3-39).

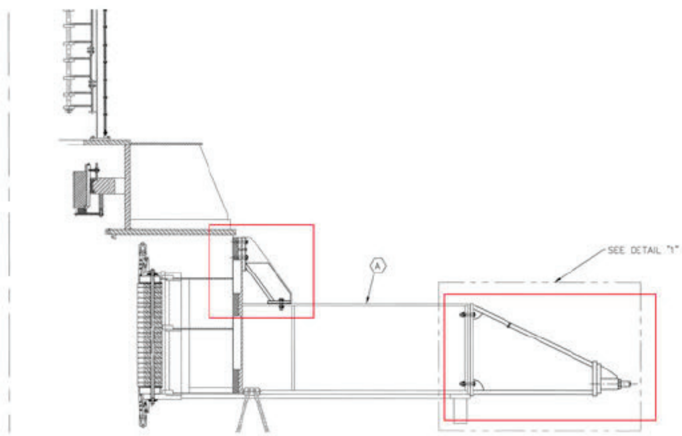


Figure 3-39. Upper Bracket Reinforcement

It's important to note however, there is still a big offset between the upper guide bearing centerline and the bracket arm radial supports which is not ideal resulting in additional flexibility due to the bending moment actuating in the structure.

Pre-design activities include:

- Perform FEA optimization study to modify the upper bracket assembly position under the pony motor to reduce the distance to the generator magnetic center line and align the bearing centerline with the arms support on the concrete foundation.
- Check and confirm the fixation of the upper bracket to the foundation to avoid concrete cracking due to thermal expansion.
- Perform FEA stress and fatigue assessment for the modified or new upper brackets.
- Calculate the new upper bracket stiffness with FEA model.

3.2.16 Combined Thrust and Guide Bracket

Estimate of Current Equipment Condition:	Good/Moderate Condition (Refurbishment and Modification Proposed)
Existing Capacity:	≥ 404 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

No special uprate studies are known for this component.

Pre-design activities include:

- Calculate the lower bracket stiffness with FEA model.
- Confirm new value of hydraulic thrust considering the new turbine runner for the uprate power.
- Perform detailed FEA stress and fatigue assessment with the updated loading.
- Check the axial deflections at the thrust bearing segment's location to ensure uniform loading.
- Check and confirm reaction forces due to thermal loads and verify stresses at fixation system.
- Verify the radial deformations at the corners and at the middle span caused by the H bracket shape.
- Perform visual and PT/MT inspections at all critical areas.

3.2.17 Thrust & Guide Bearings

Estimate of Current Equipment Condition:	Good/Moderate Condition (Refurbishment and Modification Proposed)
Existing Capacity:	≥ 460 MW (PF 0.90)
Uprate Constraint:	≥ 460 MW (PF 0.90)

The thrust bearing at Helms has a unique design wit [redacted] The pads are supported on an adjustable piston that allows the pads to tilt during operation in turbine and motor modes of operation. Based on lessons learned from the original commissioning time, special attention is required during operation to control the amount of the cooling water flow in order to avoid the pad crowing due to the differential thermal expansion across the thickness of the pad.

Voith Hydro presented the bearing calculations for the uprate power and concluded that the thrust and guide bearings are suitable to reuse.

Pre-design activities include:

- Confirm the hydraulic thrust with the new turbine runner design.
- Provide calculation for the bearing cooling system heat transfer and confirm capacity.
- Check the high-pressure lift system.
- Review OEM procedure and provide detailed disassembly and reassembly updated procedures for the thrust bearings.
- Provide detailed procedure on how to inspect and refurbish the thrust bearing pads.
- Due to its unique design, it's important to identify and validate potential suppliers prior to the outage.
- Get quotes with estimated prices and delivery times for spare set of thrust bearing pads.

3.3 GENERAL / OTHER MAJOR ELEMENTS ASSESSED

3.3.1 Water Conveyance System

Estimate of Current Equipment Condition:	**Good Condition (No Replacement/Refurbishment Proposed)**
Existing Capacity:	≥ 460 MW
Uprate Constraint:	N/A

The water conveyance system has been previously assessed by Black and Veatch (B&V) in a Helms uprate study as well as a Helms uprate transient analysis. The general conclusion was that the existing Helms water conveyance system offers sufficient hydraulic capacity for a unit uprate of 460 MW, although some further actions were listed to finalize the study. Stantec has reviewed the water conveyance system separately and concurs with B&V's conclusion – though design flows appear to far exceed those required for a feasible maximum uprate and would represent a conservative result. Stantec has identified gaps that need to be considered throughout the uprate project. These gaps are detailed in Stantec's gap analysis memorandum and are summarized here below.

The main considerations surrounding the uprate potential at Helms include the range of possible net heads under uprated flow conditions as well as the associated flow velocities throughout the entire water conveyance system. Both items are addressed in this report in the pump-turbine section 3.1 above, since turbine capacity and hydraulic capacity are directly related.

Intake-discharge structures at Courtright Lake and Lake Wishon will need to be evaluated once the uprate capacity has been confirmed. Preliminary review of these structures indicates sufficient hydraulic capacity. However, detailed calculations must be performed once the turbine uprate, and hydraulic flows have been confirmed.

B&V performed transient analyses for the proposed uprate. Two key recommendations by B&V are to conduct targeted Computational Fluid Dynamics (CFD) analyses of key locations of the water conveyance systems as well as to assess the existing surge tanks. Targeted CFD analyses will be performed by the Supplier(s) during the design phase of the project. Stantec has performed its own transient analysis to confirm the capacity of the existing surge tanks, as summarized below.

3.3.1.1 Surge Tanks

As part of the Helms uprating study a preliminary transient analysis was conducted to verify that the existing surge tanks would be adequate to handle the increase in transient pressures generated by the higher flow rates through the units.

A simple transient analysis of the Helms PSP water passages was done using the USACE computer program WHAMO1. The model does not use the unit characteristics to model the pump-turbines as detailed unit characteristics for the uprated units are not yet available. However, since the model is primarily focused on the operation of the surge tanks, the lack of the unit characteristics is not critical. The pressure transients in the scroll case should be considered only approximate, however.

Figure 3-40 shows the schematic of the WHAMO model. The model includes the various water passages, the hydropower units, and the surge tanks. The units are modeled as internal flow boundaries to allow for pumped flow, if needed. However, the current analysis is focused on generating cases only.

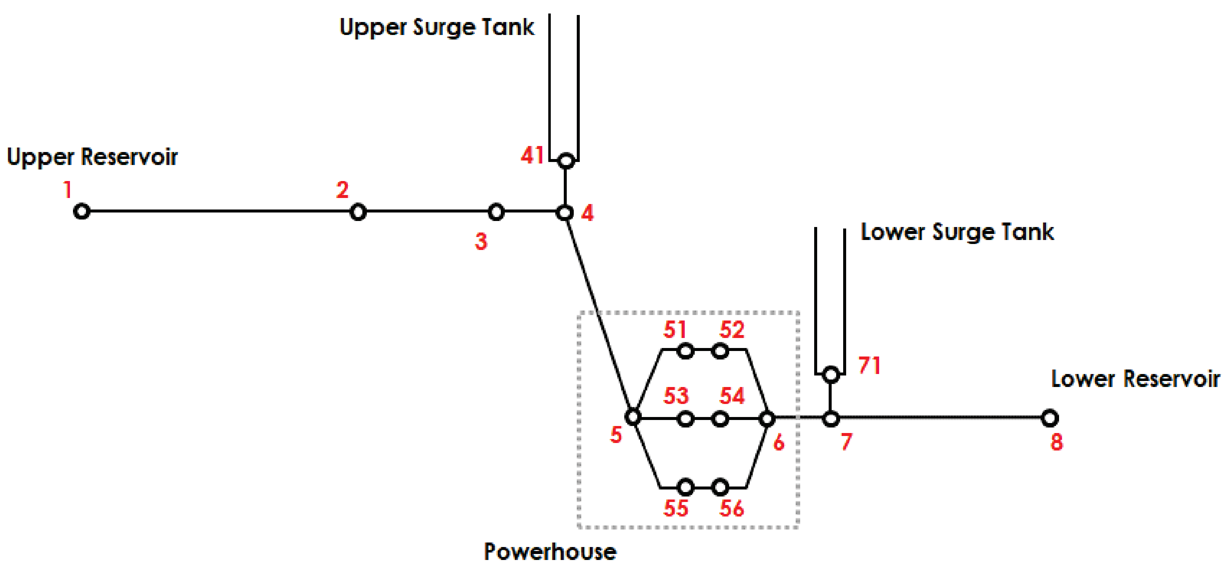


Figure 3-40. Model Schematic

Dimensions of the system components were taken from the available as-built drawings.

Model runs were made for two flow conditions – existing and uprated. Each flow condition was run with two combinations of upper and lower reservoir levels – maximum upstream and minimum downstream

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[1] WHAMO – Water Hammer and Mass Oscillation, USACE 1983.

and minimum upstream and maximum downstream. The basic parameters for the runs are summarized in Table 3-15.

Table 3-15. **Model Runs**

run	Plant Discharge	Reservoir Levels Upstream	Downstream
Base1	9000	8020	6650
Base2	9000	8184	6440
Uprate1	11700	8020	6650
Uprate2	11700	8184	6440

Each run is summarized below:

- Base1 – This run uses a discharge of 3000 cfs per unit (approximately 400 MW) for a total plant discharge of 9000 cfs. The upper reservoir is at the minimum operating level and lower reservoir is at the maximum operating level.
- Base2 – Same discharge as in Base1. The upper reservoir is now at the maximum operating level and the lower reservoir is at the minimum operating level.
- Uprate1 – An uprate discharge of 3,900 cfs per unit, for a total plant discharge of 11,700 cfs, has been assumed. The upper reservoir is at the minimum operating level and lower reservoir is at the maximum operating level. 3,900 cfs per unit was chosen as a conservative upper bound flow (and would result in an ~60 MW increase in power at minimum gross head including head loss with three-unit operation), although operation of the uprated units at this flow is not recommended. As described in section 3.1, the uprate flow for the new units will likely by limited to approximately 3,500 cfs.
- Uprate2 – Same discharge as in Uprate1. The upper reservoir is now at the maximum operating level and the lower reservoir is at the minimum operating level. This again would result in a similar ~60 MW uprate at maximum gross head (considering head losses from three-unit operation) but is beyond expected flow levels to bound the uprate condition.

For all runs the flow through the units was taken from full flow to zero in 10 seconds. This provides a further level of conservatism, as the existing wicket gates are designed for a multi-rate closure, full open to full close in 45 seconds. Refer to Figure 3-41 for gate servomotor positions under normal conditions.

[redacted]

Figure 3-41. Gate Servomotor Stroke Positions Under Normal Conditions

Error! Reference source not found. Table 3-16 shows a summary of the water levels in the head and tail tunnels and upper and lower surge tanks. The upper and lower limits of the tank are also shown for comparison. For all cases the minimum elevation is not exceeded. For run Uprate2 the water level in the upstream surge shaft comes almost to the top – another foot and it would begin to spill. For runs Base1 and Uprate1 the water level in the lower surge tank enters the air shaft above the surge shaft. However, this should not be a problem for either case.

Table 3-16. Summary of Model Results

	Head Surge Tank		Head Tunnel		Tail Surge Tank		Tail Tunnel	
Surge Tank Limits:	8325	7790			6685	6277		
run	**max**	**min**	**max**	**min**	**max**	**min**	**max**	**min**
Base1	8164.2	7920.1	8164.2	7920.1	6692.1	6587.0	6692.1	6578.2
Base2	8302.9	8086.1	8302.8	8085.9	6479.9	6366.4	6479.9	6366.3
Uprate1	8193.6	7906.8	8193.7	7906.8	6708.6	6575.9	6708.6	6545.6
Uprate2	8324.0	8076.8	8324.0	8075.8	6484.0	6340.6	6484.0	6335.0

This preliminary transient analysis indicates that the proposed maximum uprating for the Helms project can be accommodated by the existing upstream and downstream surge tanks.

3.3.1.2 Spiral Case

Since the unit characteristics are not used in this model it is not possible to get an accurate value of the pressure rise in the spiral case for each case. However, these values can be extracted from the model for comparison purposes. Table 3--17**Error! Reference source not found.** shows the maximum water levels in the spiral case for each run.

Table 3-17. Summary of Spiral Case Water Levels

run	Max Scroll Water Level	increase
Base1	8336.6	-
Base2	8507.4	-
Uprate1	8421.9	5%
Uprate2	8595.0	5%

The Hitachi spiral case drawing indicates a design pressure of 2,510 feet, and a field hydrostatic test of 3765 feet. This corresponds to a design pressure rise of 30% beyond max upper reservoir static pressure This design pressure would correspond to a water level of EL 8,750'. For all cases the maximum water level at the spiral case is below this value. The increase due to the uprating is about 5% of the static pressure.

However, due to the low specific speed of the pump-turbine, the runner will choke flow during load rejection conditions and result in an initial pressure rise that is not governed by wicket gate closing rate.

Available load rejection data was provided. A three-unit load rejection occurred in 2018 with max spiral case pressure recorded at approximately 960 psi / 2,200 feet of water column.

Multi-unit load rejection testing from 1985 indicates a worst-case spiral case pressure of 2,435 feet of water column, following a three-unit load rejection with the unit's operating between 393 / 400 MW, upper reservoir at 8,167 feet and lower reservoir at 6,542 feet, and 100% GVO. Flow is not stated, though estimated between 3,400-3,500 cfs based on reservoir levels, expected head loss, and output.

A condition of the uprate specification will be to maintain existing pressure rise design levels, but pressure rise characteristics are depending on the hydraulic design and though they can be estimated by OEMs up-front, they are accurately determined following model testing and determination of four quadrant characteristics. Once these unit characteristics are available, pressure rise following worst case load rejection will need to be verified.

3.3.2 Pump-Turbine Shutoff Valves

Estimate of Current Equipment Condition:	Poor/Moderate Condition (Requires Replacement)
Existing Capacity:	404 MW
Uprate Constraint:	≥ 460 MW

Helms has three 2,400-mm (94.5-inch)-diameter, spherical pump-turbine shutoff valves (TSV), with each valve serving an individual unit. The valves are operated by hydraulic cylinder, via water pressure from the penstock and spiral case. The valves are the original TSVs provided by Hitachi when the plant was commissioned. PG&E has had issues with these valves over the years, mainly surrounding the valve seats and mechanical locks. There have been multiple repairs, most recently in 2021 when the mechanical locks on the upstream maintenance seat of the unit 2 TSV were replaced.

The TSVs are in poor to moderate condition and replacement is recommended. PG&E has already initiated the replacement project and in the procurement phase for three new replacement valves. Replacement of the existing valves will be completed prior to uprate work on each unit, to provide a reliable upstream isolation point for the unit outage. The new valves are rated for a flow of 4,325 cfs, which corresponds to a unit output of at least 460 MW. Hence, the new TSVs are rated for the maximum uprate capacity of 460 MW.

The valves have an adjustable open and close timing of 2 – 5 minutes. Per the DOO, open and close time for the current valves is listed as 120 seconds. Timing of the new valves should be adjusted per the new turbine timing requirements and transient analysis results for the uprate.

3.3.3 Draft Tube Gates

Estimate of Current Equipment Condition:	Poor/Moderate Condition (Requires Replacement)
Existing Capacity:	404 MW
Uprate Constraint:	≥ 460 MW

The plant includes an individual draft tube assembly for each of the three units that discharges through a single shared tailrace tunnel into the lower reservoir. Each of the draft tube extensions includes an isolation gate, located at short distance downstream of the draft tube exit. These gates are hydraulically operated, single-leaf, vertically hinged flap gates. The gates are closed under balanced head conditions and – during operation – are held latched in the fully open position in a sidewall cavity. Historically, the draft tube gates have been problematic during operations and have required repeated maintenance. The inaccessibility of the gate operating equipment makes inspection and maintenance difficult; the entire plant must be shut down and the whole downstream tunnel system dewatered to access the operating equipment of each of the gates.

The draft tube isolation gates have demonstrated multiple in-service failures, unreliable position indication, questionable fixation or latching, and compromised structural integrity. Access to the gate equipment for inspection and maintenance is a costly exercise, requiring significant advance planning. The inadvertent, uncontrolled closure of a gate during pumping mode could cause catastrophic damage to the gate and unit, causing a potential long forced outage of the plant. Therefore, the consequence of gate failure is major.

Stantec has conducted an analysis of alternatives on the draft tube gates as part of a separate project. While the project is currently still ongoing, it is in the final stages and options have been narrowed down to two alternatives. Alternative A requires complete refurbishment of the existing gates. Alternative B proposes complete replacement with new bonneted slide gates. Regardless of which option is selected as the preferred option, significant refurbishment or replacement work will be necessary prior to uprating the units. The existing gates in their current condition are deemed not suitable for continued operation under new higher uprate conditions. The new gates, once or if PG&E decides to move forward with a separate refurbishment/replacement project, can be design for the higher flows associated with the proposed unit uprate.

3.3.4 Station Switchyard System

3.3.4.1 Station Switchyard

Estimate of Current Equipment Condition:	Moderate Condition (Replacement Proposed)
Existing Capacity:	405 MW
Uprate Constraint:	≥ 460 MW

The switchyard is located above ground connecting the three underground GSU transformer banks, consisting of 3 single phase 150 MVA, 18 Kv – 230 Kv in each bank, to the two Helms-Gregg 230 Kv transmission lines. The switchyard contains five 230 Kv circuit breakers, nine 230 Kv air switches, and the associated bus work. One breaker is associated with each generator unit and the other two are used as bus intertie breakers. The two transmission lines, connected between the unit and intertie breakers, may be isolated to assure one line does not become overloaded in the event the other line is lost. Power from the generator-motors is transmitted via the isophase bus to the nine single-phase transformers in the transformer chamber adjacent to the main chamber. The transformer banks are located underground to minimize losses in transmission to the aboveground switchyard, step-up the generator voltage from 18 Kv to 230 Kv. The power is then conveyed 1,100 feet up the vertical shaft to the surface by nine 2,000 KCM 230 Kv oil-filled, paper-insulated cables.

Most of the existing electrical equipment in the switchyard is the original equipment installed in 1985 and has been in service for 38 years, that is either close to or beyond their expected service life. Continued operation of electrical equipment beyond their service life expectancy may lead to equipment malfunction and failure, equipment and other property damage, unscheduled outages, and personnel injury. The existing capacity of GSU transformers and their associated 230 Kv overhead bus and the 230 Kv oil-filled paper-insulated cables connecting them to the switchyard will not be adequate for the uprate capacity of 460 MW / 506 MVA and should be replaced. Even though most of the existing electrical equipment located in the switchyard is rated to withstand the uprate capacity of 460 MW, the present condition of the equipment should be evaluated based on the most recent operation and maintenance records and testing reports to ensure their continued reliable and safe operation, however replacement of electrical equipment that has been in service close to or longer than their expected service life is recommended.

3.3.4.2 Circuit Breakers

Estimate of Current Equipment Condition:	Moderate Condition (Replacement Proposed)
Existing Capacity:	1,075 MW
Uprate Constraint:	≥ 460 MW

The switchyard contains five 230 Kv, 3,000 A circuit breaker to tie the generating units to the transmission lines. Three of the circuit breakers connect the three units to the tie bus. The other two circuit breakers are located on the tie bus, one between Unit 1 and Unit 2 breakers and one between the Unit 2 and Unit 3 breakers. The two 230 Kv transmission lines are connected to the Unit 1 and Unit 3 ends of the tie bus. From there, the two lines travel to Gregg Substation.

The five 230 Kv, 3,000 A circuit breakers are SF6 type manufactured by ASEA Brown Boveri (ABB). The three generating unit breakers are of the 242 PA type with a type AHMA-8 hydraulic spring operating mechanism. The remaining two are of the 242 PMG type with a type AHMA-8 hydraulic spring operating mechanism.

Condition Assessment

These circuit breakers are original equipment installed in 1985 and have been in service for 38 years. The expected service life of a HV circuit breaker is not indicated on the CEATI Report No. T092700-0367-1, however the typical expected service life of a HV circuit breaker is 30 years.

The maintenance history provided by PG&E shows overhaul of the generating units 1, 2, and 3 circuit breakers 270, 280, and 290 to prevent catastrophic failure in 2015 (CB-270 & CB-290) and 2018 (CB-280). These three breakers are most likely in better operating condition than their original condition due to their overhaul in 2015 & 2018, however all five circuit breakers may require frequent maintenance in coming years and have a higher chance of failure due to their 38 years in operation.

Uprate Limits

The 3,000 A rating of the 230 Kv circuit breakers will be adequate for the uprate capacity of 460 MW / 506 MVA, however their performance and functionality could be impacted by the 38 years in service. Condition assessment of the circuit breakers present condition based on the recent testing results will be needed, however since the circuit breakers have surpassed their expected service life, it is recommended that they will be replaced.

3.3.4.3 Disconnect Switches

Estimate of Current Equipment Condition:	**Moderate Condition (Replacement Proposed)**
Existing Capacity:	1,075 MW
Uprate Constraint:	≥ 460 MW

There are nine 230 Kv air switches located in the switchyard. Two air switches are motor-operated and are used to disconnect the two 230 Kv lines from the switchyard. Three manually operated air switches are used to disconnect the units and associated 230 Kv cables and breakers from the switchyard for maintenance; one air switch is associated with each unit. The remaining four air switches are used to segregate the tie bus 230 Kv breakers from the switchyard when required; one air switch is located on each side of each of the two 230 Kv tie bus breakers.

The air switches are an integral part of the switchyard equipment and operation and therefore an integral part of the powerhouse operation. Loss of any of the air switches except those associated with the tie bus will place one or more units out of service.

All nine air switches were manufactured by Siemens-Allis of Portland, Oregon. The air switches are type AVB vertical break, rated at 3,000 amps, 230 Kv, and 1 050 Kv BIL. As noted above, two of the air switches are motor operated, and the remainders are manually operated.

Condition Assessment

These air switches are original equipment installed in 1985 and have been in service for 38 years. The expected service life of a HV disconnect switch based on the CEATI Report No. T092700-0367-1 is 40 years.

The maintenance history provided by PG&E does not shows any record of maintenance or testing on these air switches. The air switches may require frequent maintenance in coming years and a higher chance of failure due to their 38 years in operation.

Uprate Limits

The 3,000 A rating of the disconnect switches will be adequate for the uprate capacity of 460 MW / 506 MVA, however their performance and functionality could be impacted by the 38 years in service. Condition assessment of the disconnect switches present condition based on recent testing reports will be needed, however since the disconnect switches are nearing their expected service life, it is recommended that they will be replaced.

3.3.4.4 Buses

Estimate of Current Equipment Condition:	**Moderate Condition (Replacement Proposed)**
Existing Capacity:	423 MW
Uprate Constraint:	≥ 460 MW

There are three categories of 230 kV buses in the switchyard and one 230 Kv category of bus in the GSU transformer chamber as listed below in Table 3-18:

Table 3-18. Categories of 230kV Bus

Bus Name	Bus Description
Bus 1, 2, and Tie Bus	230 Kv, 2,620 Ampacity, Tubular Extra Heavy Aluminum, 3-1/2" IPS, ANSI Schedule 80 Seamless
Spare Transfer Bus	230 Kv, 3,785 Ampacity, Tubular Extra Heavy Aluminum, 5" IPS, ANSI Schedule 80 Seamless
Circuit Breaker 270, 280 & 290 Bus	230 Kv, 1,825 Ampacity, Tubular Extra Heavy Aluminum, 2-1/2" IPS, ANSI Schedule 80 Seamless
GSU 1, 2, 3 Overhead Bus	230 Kv, 1,180 Ampacity, Tubular Extra Heavy Aluminum, 2" IPS, ANSI Schedule 80 Seamless

Condition Assessment

These buses are original equipment installed in 1985 and have been in service for 38 years. The expected service life of a HV bus based on the CEATI Report No. T092700-0367-1 is 50 years.

The maintenance history provided by PG&E does not show any record of maintenance or testing on these buses. The buses may require frequent maintenance in coming years due to their 38 years in operation. Operational performance for the bus is assumed to be normal and meet the original design criteria. It is assumed that the bus has no physical deterioration.

Uprate Limits

The 230 Kv bus Ampacity rating indicated in the table above for the GSU 1, 2, 3 overhead bus will not be adequate for the uprate capacity of 460 MW / 506 MVA and should be replaced. The remaining 230 Kv buses Ampacity ratings indicated in the table above will be adequate for the uprate capacity of 460 MW / 506 MVA and they can remain in service for an estimated 12 years, if there are no damages that would impact their integrity and capacity, before they reach their end of service life at which time they need to be replaced.

3.3.4.5 High Voltage Cables

Estimate of Current Equipment Condition:	Moderate Condition (Replacement Proposed)
Existing Capacity:	412 MW
Uprate Constraint:	≥ 460 MW

There are ten (nine plus one spare) 230 Kv cables that are the primary connection between the powerhouse and the switchyard. The cables transmit power from the units to the switchyard when the units are operating in the generate mode. The cables transmit power from the switchyard to the units when the units are operating in the pump mode. Three cables are associated with each unit (3 phase circuit). The remaining cable serves as a common spare and is kept energized at all times without load.

Each 230 Kv cable extends from the 230 Kv bus in the switchyard to one of the nine GSU transformers in the powerhouse. The spare cable is terminated at a pothead near the spare GSU transformer at the east end of the transformer gallery. Each cable is continuous and has no splices. Each cable is terminated with potheads at the switchyard and the powerhouse. The potheads control the electrical stresses at the cable ends and serve to seal out moisture.

The 230 Kv cables are of the single conductor, self-contained, oil-filled type and were manufactured by Standard Telefon og Kabelfabrik of Oslo, Norway. The conductor is 2,000 kcmil copper and is insulated with 760 mils of oil impregnated paper tapes. The cable is rated 230 Kv, 1,150 A, 1,050 Kv BIL. The outer diameter of the cable is approximately 4 inches. See Table 3-19 below for details.

Table 3-19. 230kV Cable Data

Manufacturer	Standard Telefon OG Kabelfabrik Norway
Type	230 Kv, Hollow Core Copper, Oil-filled, self-contained
Number	10 (1 spare)
Conductor Size (KCmil)	2,000 KCmil
Ampacity	1,150 A
BIL	1,050 Kv
Insulation	760 mils of Oil impregnated paper tape

Condition Assessment

These HV cables are original equipment installed in 1985 and have been in service for 38 years. The expected service life of a HV cable based on the CEATI Report No. T092700-0367-1 is 40 years.

The maintenance history provided by PG&E does not show any record of failure, repair, or testing on these HV cables. The HV cables are close to their service life expectancy due to their 38 years in operation with a higher chance of failure in the coming years.

Uprate Limits

The 230 Kv cables Ampacity rating indicated in the table above will not be adequate for the uprate capacity of 460 MW / 506 MVA, and since the cables are nearing their expected service life, it is recommended that they will be replaced.

3.3.4.6 Capacitor Power Transformers and Line Traps

Estimate of Current Equipment Condition:	Moderate Condition (Replacement Proposed)
Existing Capacity:	405 MW
Uprate Constraint:	≥ 460 MW

There are twelve Capacitor Power Transformers in the switchyard rated 132.8 Kv / 115-66 V that provide power to different meters, instruments, and protective devices. There are also two Line Traps on the transmission lines for remote control signals, remote metering, and communication.

Condition Assessment

The Capacitor Power Transformers and line traps are original equipment installed in 1985 and have been in service for 38 years. The expected service life of a Capacitor Power Transformer and Line Trap is not indicated in the CEATI Report No. T092700-0367-1, however the typical expected service life of a Capacitor Power Transformer and Line Trap is 30 years.

The maintenance history provided by PG&E does not show any record of maintenance or testing on these units. The Capacitor Power Transformers and Line Traps may require more frequent maintenance and testing with a higher chance of failure in the coming years due to their 38 years in operation.

Uprate Limits

The Capacitor Power Transformers and Line Traps capacity will require to be evaluated with the uprate capacity of 460 MW / 506 MVA based on the additional meters, instruments, and protective devices that may have to be added to the system, however since the Capacitor Power Transformers and line traps have surpassed their expected service life, it is recommended that they will be replaced.

3.3.4.7 Lightning Arresters

Estimate of Current Equipment Condition:	Moderate Condition (Additions or Modifications Proposed)
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

There are ten (nine plus one spare) lightning arresters on the cable bus from the GSU transformer banks to the 230 Kv switchyard circuit breakers 270, 280, 290 for each unit. There are no lightning arresters on the transmission line side of the switchyard, but those should be added if required based on analysis. It may also be possible to increase the height of the existing lightning arresters to cover the entire switchyard. A lightning protection study should be performed to determine the best course of action.

3.4 BALANCE OF PLANT (ELECTRICAL)

Refer to Table 3-20 below for a summary of typical electrical BOP assessment work scope items.

Table 3-20. Summary of Typical Electrical BOP Assessment Work Scope Items

System	Condition Assessment Summary
Starting Motor Transformers	These transformers are original equipment installed in 1985 and have been in service for 38 years. The expected service life of a transformer based on the CEATI Report No. T092700-0367-1 is 35 years. Regardless of the alternative selected for future work the starting motor transformers will need to be replaced as part of any refurbishment or uprate of motor-generator units.
13.8 kV Station Service Bus (Starting Motor Bus)	The bus is the original equipment installed in 1985 and has been in service for 38 years. The expected service life of a medium voltage bus based on the CEATI Report No. T092700-0367-1 is 40 years. Regardless of the alternative selected for future work, the 13.8 kV station service bus segments between the 13.8 kV station service switchgear and excitation system and station service transformers should be replaced as part of any refurbishment or uprate of motor-generator units.
13.8 kV Station Service Switchgear	The switchgear for each unit is original equipment installed in 1985 and in service for 38 years. The expected service life of a medium voltage switchgear based on the CEATI Report No. T092700-0367-1 is 35 years. The frequency of corrective maintenance may increase in coming years causing unplanned outages. Switchgear condition is considered moderate and based on the inspection and test results, a refurbishment or replacement is proposed.
Station Service Transformers #1, 2, 3 and 4	Transformers 1 to 4 are original equipment and have been in service for 38 years. The expected service life of transformers based on the CEATI Report No. T092700-0367-1 is 35 years. It is assumed that the transformers may require frequent maintenance in coming years causing unplanned outages. Transformers condition is considerate Moderate, but a replacement is proposed to replace oil filled transformers #1 to 3 with dry-type and get the next 35 years of operation.
480V Station Service Switchgear	The expected service life of a low voltage station service switchgear based on the CEATI Report No. T092700-0367-1 is 35 years. The 480V Station Service Switchgear was replaced in 2005. The maintenance history provided by PG&E shows normal preventive maintenance performed on the switchgear breakers including breakers and bus protection and arc-flash devices. Equipment is in good condition, replacement not recommended.
Load Centers 1 to 10	The expected service life of a load center based on the CEATI Report No. T092700-0367-1 is 35 years. According to the Description of Operation document, load centers 1, 2, 7 and 8 were replaced in 2018, and load centers 6 and 9 were replaced in 2015. According to the PG&E's Maintenance History, load center 3 was replaced in 2006, load center 4 was replaced in 2005, and load center 10 was installed in 2009. The maintenance history provided by PG&E shows normal preventive maintenance performed on the load centers. The equipment is in good condition and replacement not recommended; however, the unit auxiliary starters and contactors in the load centers should be evaluated to verify if they could be reused or replaced for operation with uprated unit.
Emergency Diesel Generator	No changes to the diesel generator are anticipated for the alternatives. Equipment is in good condition.

System	Condition Assessment Summary
125VDC Station Power System	The VLA battery life is 20 years per CEATI Report No. T092700-0367-1. Both the main and auxiliary battery banks have been in service for 38 years and there is no record of when they were replaced. The maintenance history shows normal maintenance performed on the battery banks. It is recommended to have the main and auxiliary battery banks inspected and tested. Refurbish or replace them if the test results show the battery may have problems and cause unplanned outages in future. Depending on the alternative selected, the system needs to be evaluated.
Uninterruptible Power Supply (UPS)	The expected service life of a UPS based on the CEATI Report No. T092700-0367-1 is 35 years. The UPS was replaced in 2013 and it has been regularly inspected and tested. The UPS should be in good condition and could be reused for uprated units. Equipment is in good condition, replacement not recommended.
Lighting System	The lighting system is approaching the end of its service life and should be replaced to extend its service life to another 40 years. It is recommended to replace the existing lighting system with energy efficient, environmentally friendly, and longer lifespan LED fixtures.
Protection and Control Systems	The protective relays were upgraded in 2010 and have been in service without any problems. The settings for these relays will have to be updated for uprated units. The tripping scheme for each motor-generator unit will have to be updated when motor-generator circuit breaker is installed between the main bank transformer and motor-generator unit. Depending on the alternative selected, the system needs to be evaluated.

3.4.1 Medium and Low Voltage Station Service

The medium and low voltage station service equipment in service at Helms Pumped Storage Plant include the following equipment:

<u>Starting Motor Transformers #11, 12 and 13</u>

Estimate of Current Equipment Condition:	Moderate Condition (Replacement Proposed)
Existing Capacity:	404 MW
Uprate Constraint:	≥ 460 MW

There is one Starting Motor Transformer for each unit. Any of the Starting Motor Transformers can supply the minimum station service power required to operate the powerhouse in addition to the power necessary to operate the starting motor. Transformer #11 serves unit 1 excitation and station service loads during generating and pumping operations. Transformer #11 can also provide start-up power to units 2 and 3 pony motor during pump start when the phase reversing switch of unit 1 is in disconnect position and unit 1 breaker is closed, or if the unit 1 is already in pump mode and paralleled with the system. Transformers #12 and #13 are configured like Transformer #11 and provide similar functionality as Transformer #11.

Each transformer is oil filled and rated as follows (Table 3-21):

Table 3-21. Starting Motor Transformers Data

Item	Rating		
Windings	2 Winding		
MVA Rating	12 MVA		
High Voltage (HV) Primary	18,000 V delta		
Low Voltage (LV) Secondary	13,800 V / 7,967 V wye-grounded		
Voltage Impedance at rated voltage tap	5.67%		
LV Taps	+2/-2 x 2½ % Taps on Low Voltage		
	Tap	%	Primary Voltage
	1	-5.0%	13,100 Volts
	2	-2.5%	13,450 Volts
	3	0%	13,800 Volts
	4	+2.5%	14,150 Volts
	5	+5.0%	14,500 Volts
Frequency	60 Hz		
Phase	3		
Coolant	Mineral Oil		
Cooling Type	Oil Natural Air Natural (ONAN)		
Temperature Rise	65°C		
Winding BIL HV BIL LV neutral BIL LV	 150 kV 110 kV 110 kV		
Bushing Current Transformers LV	**Qty/Bushing** 1		**Ratio** 1500/5 SR

<u>Condition Assessment and Uprate Limit</u>

These transformers are original equipment installed in 1985 and have been in service for 38 years. The expected service life of a transformer based on the CEATI Report No. T092700-0367-1 is 35 years.

The maintenance history provided by PG&E shows normal preventive maintenance performed on these transformers. There are no major repairs documented in the maintenance history other than minor repairs to resolve low oil level alarm, relocate temperature gauge, and clean bushings. The transformer may require frequent maintenance in coming years that would cause unplanned outages.

It is assumed that the transformers are performing adequately and meet the original design criteria but less efficient and effective than when originally installed.

It is assumed that the physical deterioration for these transformers is more than cosmetic but has not yet compromised physical/structural integrity.

Regardless of the alternative selected for future work the starting motor transformers will need to be replaced as part of any refurbishment or uprate of motor-generator units.

13.8 kV Station Service Bus (Starting Motor Bus)

Estimate of Current Equipment Condition:	Moderate/Good Condition (Replacement Proposed)
Existing Capacity:	404 MW
Uprate Constraint:	≥ 460 MW

Each unit has a medium voltage station service bus for connection of the respective unit's starting motor transformer and 13.8 kV station service switchgear, and for connections of respective unit's 13.8 kV station service switchgear to starting motor, excitation system transformer and station service transformer. The bus is 3-phase insulated (copper or aluminum bar) non-segregated phase duct and rated as follows (Table 3-21):

Table 3-21. Station Service Bus Rating

Item	Ratings
Nominal Operating Voltage	13.8 kV
Maximum Bus Voltage	14.4 kV
Basic Insulation Level (BIL)	110 kV
Rated Continuous Current	1,200 Amps

The maximum current that the bus will be required to carry is when the unit's motor starting transformer is supplying power to the respective unit's pony motor, station service and excitation loads. The pony motor load is for a very short time during starting of a unit in the pumping mode. The excitation load is not on during pump start-up until the unit speed has reached 80 to 90%, so the total load shown below (Table 3-22) for pump start-up is momentary and for a very short time.

Table 3-22. Loads on the Starting Motor Bus

Equipment	Pump Start-up	Pumping	Generating
Pony Motor	744 A	0 A	0 A
Excitation System	84 A	84 A	84 A
Station Service	105 A	105 A	105 A
Total Load (Ampere)	933 A	189 A	189 A

Condition Assessment and Uprate Limit

The bus is the original equipment installed in 1985 and has been in service for 38 years. The expected service life of a medium voltage bus based on the CEATI Report No. T092700-0367-1 is 40 years. The maximum current the bus may carry for a very short time is 80% of the bus ampere rating during pump startup, and the maximum continuous current bus will be carrying at any given time is less than 16% of the bus ampere rating so the bus should have ample of capacity to support higher loads and remaining service life than the expected service life indicated in the CEATI report as the bus has been loaded much less than its nominal rating and has never been operated under overload conditions.

The maintenance history provided by PG&E shows normal preventive maintenance performed on the bus. There are no major repairs documented in the maintenance history and the bus has never been operated in overload conditions, so it is assumed the bus is adequate for reuse.

Operational performance for the bus is assumed to be normal and meet the original design criteria.

It is assumed that the bus has no physical deterioration.

Regardless of the alternative selected for future work, the 13.8 kV station service bus segments between the starting motor transformer and 13.8 kV station service switchgear, and between the 13.8 kV station service switchgear and starting motor should be inspected and tested to verify its condition and determine if it could be reused or should be replaced as part of any refurbishment or uprate of motor-generator units. The tests should include infrared thermography for verifying temperature rise while the bus is energized, and electrical tests to verify bus joint resistance, insulation resistance and dielectric withstand of electrical insulation.

Similarly, regardless of the alternative selected for future work, the 13.8 kV station service bus segments between the 13.8 kV station service switchgear and excitation system and station service transformers should be replaced as part of any refurbishment or uprate of motor-generator units. These transformers will be new dry type transformers installed on main floor or generator floor to create space required for installation of a new motor-generator breaker between the phase reversal switch and GSU transformer of each unit in the respective unit's equipment tunnel between the powerhouse main floor and GSU transformers chamber.

13.8 kV Station Service Switchgear

Estimate of Current Equipment Condition:	**Moderate Condition (Refurbishment/Replacement Proposed)**
Existing Capacity:	404 MW
Uprate Constraint:	≥ 460 MW

Each unit has one medium voltage (metal enclosed or metal-clad) switchgear with five vertical sections, four electrically operated draw-out breakers, potential transformers, current transformers, metering and protection devices, and control and indicating devices. The ratings and characteristics of the switchgear and breakers are as shown in table below (Table 3-23):

Table 3-23. Switchgear and Breakers Ratings

Item	Ratings
Switchgear Type	Metal-Clad or Metal Enclosed
Nominal Operating Voltage	13.8 kV
Maximum Operating Voltage	14.4 kV
Breaker Type	Vacuum Interrupter
Rated Continuous Current	1,200 A
Type of Operating Mechanism	Electrically Operated

Each breaker is operated locally at the switchgear or remotely from the control room. The four breakers consist of the excitation transformer supply breaker 52ET, the station service transformer supply breaker 52ST, the starting motor bus breaker 52 which connects the starting motor tie bus with the starting motor transformer, and the starting motor breaker 52SM which connects the starting motor primary with the starting motor tie bus.

Condition Assessment and Uprate Limit

The switchgear for each unit is original equipment installed in 1985 and in service for 38 years. The expected service life of a medium voltage switchgear based on the CEATI Report No. T092700-0367-1 is 35 years.

The maintenance history provided by PG&E shows rare corrective maintenance performed on the switchgear breakers including breakers repaired in 2009 and 2 breakers replaced in 2007. The frequency of corrective maintenance may increase in coming years causing unplanned outages.

The maintenance history indicates unit 1 station service breaker had failed to close in 2005 and this issue was corrected. There are no other operational failures noted in the maintenance history, therefore it is assumed that the operational performance for the switchgear breakers is adequate and meets the original design criteria.

It is assumed that the performance will be significantly affected in coming years due to excessive wear and tear on the breaker operating mechanism and moving parts caused from many years of operation.

Regardless of the alternative selected for future work, the 13.8 kV station service switchgear should be inspected and tested, and based on the test results, the switchgear and breakers should be refurbished or replaced as required to provide another 40 years of service life.

Station Service Transformers #1, 2, 3 and 4

Estimate of Current Equipment Condition:	Moderate Condition (Replacement Proposed)
Existing Capacity:	≥ 404 MW
Uprate Constraint:	≥ 460 MW

Station Service Transformer #4 supplies normal station service power via 21 kV line from Woodchuck substation to powerhouse when units 1 to 3 are offline or 230 kV breakers for units 1 to 3 are open. Station Service Transformer #1, 2 or 3 supply alternate station service power when the respective units 1, 2, or 3 is online, or unit's 230 kV breaker is closed with the respective unit's reversing switch in disconnect position.

Any of the Station Service Transformer 1, 2, 3, or 4 can supply the minimum station service power required to operate the powerhouse.

Transformers 1, 2 and 3 are oil filled and each rated as follows (Table 3-24):

Table 3-24. Station Service Transformer 1-3 Ratings

Item	Rating	
Windings	2 Winding	
kVA Rating	2,500 kVA	
High Voltage (HV) Primary	13,800 V delta	
Low Voltage (LV) Secondary	480 V / 277 V wye-grounded	
Frequency	60 Hz	
Phase	3	
Coolant	Mineral Oil	
Cooling Type	Oil Natural Air Natural (ONAN)	
Bushing Current Transformers	**Qty/Bushing**	**Ratio**
HV	2	600/5 MR
LV neutral	1	

Transformer 4 is heavy duty dry type and includes a compartment with 100 A fused disconnect switch on which the 21 kV line is terminated, and a 21 kV lightning arrestor. The transformer 4 is rated as follows (Table 3-25):

Table 3-25. Station Service Transformer 4 Rating

Item	Rating	
Windings	2 Winding	
kVA Rating	2,500 kVA	
High Voltage (HV) Primary	21,000 V delta	
Low Voltage (LV) Secondary	480 V / 277 V wye-grounded	
Frequency	60 Hz	
Phase	3	
Current Transformers	**Qty**	**Ratio**
LV	1	
LV neutral	1	

Drawings 459531 and 459532 show loads connected to the 480V Station Service Switchgear bus 1 and 2. Based on a preliminary calculation, the total load connected to bus 1 and 2 is estimated to be 3,900 kVA and 4,100 kVA, respectively. Bus 2 is used as an alternate source for excitation system and the total connected load derived above excludes the three unit's excitation load. The total demand load on bus 1 and 2 with all three units operating including power for essential and non-essential BOP equipment is estimated to be 980 kVA and 1,175 kVA, respectively. Therefore, each Station Service Transformer #1, 2, 3 or 4 rated at 2,500 kVA has approximately 345 kVA of spare capacity to support new loads (Table 3-26).

Table 3-26. Bus Loads on Station Service Transformers.

480V Station Service Switchgear			
Bus 1 Connected Load	Bus 2 Connected Load	Bus 1 Max Demand Load (3 Units Running & Powerhouse Essential and Non-Essential Loads)	Bus 2 Max Demand Load (3 Units Running & Powerhouse Essential and Non-Essential Loads)
3,900 kVA	4,100 kVA	980 kVA	1,175 kVA

Condition Assessment and Uprate Limit

Transformers 1 to 4 are original equipment and have been in service for 38 years. The expected service life of transformers based on the CEATI Report No. T092700-0367-1 is 35 years.

It is assumed that the transformers may require frequent maintenance in coming years causing unplanned outages.

It is assumed that the transformers are performing adequately and meet the original design criteria but less efficient and effective than when originally installed.

It is assumed that the physical deterioration for these transformers is more than cosmetic but has not yet compromised physical/structural integrity.

Regardless of the alternative selected for future work, the station service transformers #1 to 3 should be replaced with dry-type and installed on main floor or generator floor to create space required for installation of a new motor-generator breaker between the phase reversal switch and GSU transformer of each unit in the respective unit's equipment tunnel between the powerhouse main floor and GSU transformers chamber.

480V Station Service Switchgear

Estimate of Current Equipment Condition:	Good Condition (Re-use Proposed)
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

480V Station Service Switchgear is divided into two sections corresponding to the two 480V Bus 1 and Bus 2. Station Service Transformer #4 secondary is connected to 480V Station Service Bus 1 and Bus 2 via 480V Station Service Switchgear source breakers 52S4-1 and 52S4-2, respectively. Station Service Transformers #1 and 2 secondary is connected to 480V Station Service Bus 1 via 480V Station Service Switchgear source breakers 52S1-1 and 52S2-1, respectively. Station Service Transformers #3 secondary is connected to 480V Station Service Bus 2 via 480V Station Service Switchgear source breaker 52S3-2. The 480V Station Service Bus 1 and Bus 2 is connected via 480V Station Service Switchgear bus-tie breaker 52SBT. The 52SBT is normally closed. The 480V Station Service Bus 1 has ten feeder breakers and Bus 2 has eight feeder breakers to supply power to the units 1 to 3 auxiliaries and powerhouse BOP equipment through load centers 1 to 10. The 480V Station Service Switchgear source and feeder breakers are draw-out types and the switchgear includes an arc-flash protection system for safety of maintenance personnel and equipment. The 480V Station Service Switchgear is configured to allow only one source to connect to the 480V Station Service Bus 1 and 2 at any given time. Each Bus 1 and 2 could be fed from two independent sources with bus-tie breaker 52SBT in open position.

The ratings and characteristics of the 480V Station Service Switchgear are as shown in Table 3-27 below:

Table 3-27. 480V Station Service Switchgear Ratings

Item			Ratings
Switchgear Type			Metal Enclosed NEMA 1
Nominal Operating Voltage			480 V
Maximum Design Voltage			635 V
Main Bus Continuous Current			3,200 A
Breaker Type			Magnum MDS
Rated Continuous Current	Main Source Breaker	52S1-1	3,200 A
		52S2-1	
		52S3-2	
		52S4-1	
		52S4-2	
	Bus-Tie Breaker	52SBT	3,200 A
	Bus 1 Feeder Breaker	52LC1	1,600 A
		52LC3	3,200 A
		52LC7	800 A
		52S6	800 A
		52PC	800 A
		52C1SA	800 A
		52C3SA	800 A
		52SP-F9D	800 A
		52SP-F10C	800 A
		52SP-F10D	800 A
		52LC2	1,600 A

Item			Ratings
	Bus 2 Feeder Breaker	52LC4	3,200 A
		52LC8	800 A
		52LC10	1,600 A
		52C2SA	800 A
		52EB	3,200 A
		52SP-F2C	800 A
		52SP-F4B	800 A
Type of Operating Mechanism		Main Source & Bus-Tie Breaker	Electrically Operated

Condition Assessment and Uprate Limit

The expected service life of a low voltage station service switchgear based on the CEATI Report No. T092700-0367-1 is 35 years. The 480V Station Service Switchgear was replaced in 2005.

The maintenance history provided by PG&E shows normal preventive maintenance performed on the switchgear breakers including breakers and bus protection and arc-flash devices.

There are no operational failures noted in the maintenance history, therefore it is assumed that the switchgear breakers are performing adequately and meet the original design criteria.

It is assumed that there may be some wear and tear on the main source breaker's operating mechanism and moving parts as they may have been operated more frequently to keep the power available to the powerhouse equipment. It is assumed that the bus-tie and feeder breakers should have no wear and tear as they are rarely operated.

Regardless of the alternative selected for future work, it is proposed to reuse the 480V station service switchgear.

Load Centers 1 to 10

Estimate of Current Equipment Condition:	Good Condition (Evaluation Proposed)
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

There are ten 480V and 208/120V load centers equipped with motor starters, feeder breakers, transformers, manual and automatic transfer switches, and control and indication devices to provide power to units 1 to 3 auxiliaries and powerhouse equipment. The ratings and characteristics of the 480V and 208/120V Load Centers are shown in Table 3-28 below:

Table 3-28. Load Center Characteristics

Item		Ratings
Nominal Operating Voltage	Load Centers 1, 2, 3, 4, 5, 6, 10	480 V
	Load Centers 7, 8, 9	208/120 V
Maximum Design Voltage		600 V
Short-Circuit Current	Load Centers 1, 2, 7, 8	65 kA
	Load Centers 3, 4	30 kA
Continuous Current	Load Centers 1, 2, 10	1,200 A
	Load Centers Transfer Section 1-2	600 A
	Load Centers 3, 4	2,500 A
	Load Centers 6, 7, 8, 9	600 A

Condition Assessment and Uprate Limit

The expected service life of a load center based on the CEATI Report No. T092700-0367-1 is 35 years. According to the Description of Operation document, load centers 1, 2, 7 and 8 were replaced in 2018, and load centers 6 and 9 were replaced in 2015. According to the PG&E's Maintenance History, load center 3 was replaced in 2006, load center 4 was replaced in 2005, and load center 10 was installed in 2009.

The maintenance history provided by PG&E shows normal preventive maintenance performed on the load centers.

There are no operational failures or physical deterioration noted in the maintenance history, therefore it is assumed that the load centers are performing adequately and meet the original design criteria.

Regardless of the alternative selected for future work, it is proposed to reuse the load centers. The size and capacity of the unit auxiliary's starter and contactor will be evaluated to verify if they require replacement with a larger size for operation with uprated unit.

Emergency Diesel Generator

Estimate of Current Equipment Condition:	Good Condition Good Condition (Re-use Proposed)
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

The diesel generator rated 480V, 115 kW located in the switchyard control building supplies emergency power to load centers 6, 7, and 9 upon loss of normal ac source. It is sized to provide power to one battery charger, powerhouse emergency lighting and shaft elevator. It is not critical to unit operation as it does not have the capacity to support loads for unit operation. The diesel generator has been in service for 38 years. There is no maintenance history for the diesel generator, so it is assumed the diesel generator is in good condition.

No changes to the diesel generator are anticipated for the alternatives.

125VDC Station Power System

Estimate of Current Equipment Condition:	Moderate Condition (Evaluation Proposed)
Existing Capacity:	404 MW
Uprate Constraint:	≥ 460 MW

The 125VDC station power system provides power to plant critical systems such as protection systems, standby pumps, and emergency lighting and it consists of a 125Vdc main station battery, 125Vdc auxiliary station battery, and 125Vdc switchgear and battery charging equipment.

The ratings and characteristics of each station battery are as follows (Table 3-29):

Table 3-29. Station Battery Characteristics

Item	Rating
Rated Voltage	125 VDC
Type	Vented Lead Acid (VLA)
Number of Cells per Bank	60
Nominal Ah Capacity per Bank	960
Duty Cycle	8 Hours
End of Duty Cycle Minimum Cell Voltage at 77 Degree F	1.75 Volts
Nominal Cell Voltage	2 Volts
Maximum Charge Voltage per Cell	2.4 Volts

The 125Vdc switchgear consists of two panels with dc distribution branch circuit breakers and two panels with three battery chargers (two main chargers 1 and 2, and one alternate charger 3) with their controls and instrumentation. Normally, all three chargers are in service supplying the dc load of the powerhouse and providing a floating charge to the two batteries. Either main charger 1 or 2 has the capacity to supply dc control power load for the powerhouse. Either main charger 1 or 2 also serves as an alternate charger to the auxiliary battery when alternate charger 3 fails.

The ratings and characteristics of each battery charger are as follows (Table 3-30):

Table 3-30. Battery Charger Characteristics

Item	Rating
Output Current	35 A
Input Voltage, AC	208VAC, 3-Phase, 60 Hz
Nominal Output Voltage, DC	125VDC

Condition Assessment and Uprate Limit

The VLA battery life is 20 years per CEATI Report No. T092700-0367-1. Both the main and auxiliary battery banks have been in service for 38 years and there is no record of when they were replaced. The maintenance history shows normal maintenance performed on the battery banks. It is recommended to have the main and auxiliary battery banks inspected and tested. Refurbish or replace them if the test results show the battery may have problems and cause unplanned outages in future.

The expected service life of a battery charger based on the CEATI Report No. T092700-0367-1 is 35 years. The battery chargers were replaced in 2017 and they have been regularly inspected and tested. The battery chargers should be in good condition and could be reused for uprated units.

Regardless of the alternative selected for future work, it is proposed to inspect and test the battery banks and evaluate if they require replacement to provide another 40 years of service life and for operation with uprated units.

Uninterruptible Power Supply (UPS)

Estimate of Current Equipment Condition:	Good Condition (Re-use Proposed)
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

The UPS supplies essential ac power to critical loads that must remain energized during the operation of the power plant. There are two industrial grade pulse width modulated UPS connected in parallel and each UPS capable of carrying all the connected loads. Each UPS is fed from three sources, a normal ac source from load center 7, a dc source from 125Vdc auxiliary station battery bank, and a bypass ac source from load center 8.

The ratings and characteristics of each UPS are as follows (Table 3-31):

Table 3-31. UPS Characteristics

Item	Rating
Output Power	10 kVA
DC Input Power	125VDC
Normal AC Input Power	208VAC, 3-Phase, 4-Wire, 60 Hz
Bypass AC Input Power	208VAC, 3-Phase, 4-Wire, 60 Hz
Output Power	208VAC, 3-Phase, 4-Wire, 60 Hz
Voltage Regulation	± 1%
Total Output Harmonic Distortion	100% Linear Load < 3% 100% Non-Linear Load < 5%
Efficiency	87%

Condition Assessment and Uprate Limit

The expected service life of a UPS based on the CEATI Report No. T092700-0367-1 is 35 years. The UPS was replaced in 2013 and it has been regularly inspected and tested. The UPS should be in good condition and could be reused for uprated units.

3.4.1.1 Lighting System

Estimate of Current Equipment Condition:	Moderate/Good Condition (Replacement Proposed)
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

The lighting system consists of lighting fixtures, switches, control devices, lighting transformers and power panels located throughout the Helms power plant facilities to provide illumination for operation and maintenance personnel during normal and emergency operations of the plant.

Condition Assessment and Uprate Limit

The lighting system is approaching the end of its service life and should be replaced to extend its service life to another 40 years. It is recommended to replace the existing lighting system with energy efficient, environmentally friendly, and longer lifespan LED fixtures. LED light fixtures consume less power and dissipate less heat than incandescent, fluorescent, high-pressure sodium, and metal halide fixtures.

3.4.1.2 Protection and Control Systems

Estimate of Current Equipment Condition:	Good Condition (Evaluation Proposed)
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

Each motor-generator unit, main bank transformer, motor-generator main leads (isolated phase bus), starting motor transformer, starting motor, 230 kV cable and bus from the main bank transformer to the 230 kV switchyard, and 230 kV transmission line is protected by redundant microprocessor-based multifunction protective relays. Discrete overcurrent and undervoltage relays are provided for protection of 13.8 kV bus and feeders for station service and excitation systems. A breaker failure protection scheme is provided for the 230 kV switchyard breakers.

The existing unit and plant control system is comprised of completely integrated hard-wired control devices and unit master start/stop relays, programmable logic controllers for governor controls, digital controllers for excitation controls, distributed control system (DCS) for unit controls and monitoring from control room, direct digital control (DDC) for load controls, transformer monitoring remote terminal unit (RTU) and SCADA RTU for remote control of units.

Condition Assessment and Uprate Limit

The protective relays were upgraded in 2010 and have been in service without any problems. The settings for these relays will have to be updated for uprated units. The tripping scheme for each motor-generator unit will have to be updated when motor-generator circuit breaker is installed between the main bank transformer and motor-generator unit.

The control system and synchronizing scheme will be replaced and updated for the uprated units, including new motor-generator circuit breaker.

3.5 MAIN BANK TRANSFORMERS

Estimate of Current Equipment Condition:	Moderate Condition (Replacement Proposed)
Existing Capacity:	404 MW
Uprate Constraint:	≥ 460 MW

There are three main bank transformers, consisting of 3 G.E. single phase 150 MVA, 18 kV – 230 kV, oil filled with two oil/water Unifin heat exchangers and a G.E. Alugard II lightning arrester in each bank, for a total of nine single phase transformers plus one spare, with a combined rating of 450 MVA. Each motor-generator unit is supplied with a main bank transformer to step-up voltage from 18 kV motor-generator terminal voltage to 230 kV transmission voltage during generating mode, and step-down 230 kV transmission voltage to 18 kV motor-generator terminal voltage during pump mode. The main bank transformers are in the transformer chamber. The main bank transformer's low voltage terminals are connected to the motor-generator terminals via isolated phase bus duct, and high voltage terminals are connected to the 230 kV breaker at the surface switchyard via 230 kV oil-filled, 2,000 kcmil copper cables insulated with 760 mils of oil impregnated paper tapes.

Each unit's main bank single-phase transformers are connected in wye-grounded on the high voltage side and delta on the low voltage side. Each single-phase transformer includes two oil/water heat exchangers and lightning arrester, and has the following characteristics and ratings (Table 3-32):

Table 3-32. Main Bank Transformer Characteristics

Item	Rating	
Main Bank Transformers Manufacturer	General Electric Company	
Number of Main Bank Transformers	10 Including one spare	
Windings	2 Winding	
MVA Rating	150 MVA	
High Voltage (HV) Primary	230,000 V	
Low Voltage (LV) Secondary	18,000 V	
Frequency	60 Hz	
Coolant	Mineral Oil	
Cooling Type	Oil Forced Water Forced (OFWF)	
Winding BIL HV	825 kV graded	
Bushing Current Transformers HV	**Qty/Bushing**	**Ratio**
	2	1200/5 MRCT
	1	3000/5 MRCT
Arresters	192 kV	

Condition Assessment:

These transformers are original equipment installed in 1985 and have been in service for 38 years. The CEATI Report No. T092700-0367-1 states the average expected life for an individual transformer in a large population of transformers is statistically about 40 years.

The most important factor in determining the condition of a transformer is dissolved gas analysis (DGA). Individual and total dissolved combustible gas generation rates in the insulating oil, based on IEC and IEEE standards, indicates the condition of transformer. The analysis of insulating oil would identify internal arcing, bad electrical contacts, hot spots, partial discharge, or overheating of conductors, oil, tank, or cellulose. Other tests and analyses such as Furanic analysis and interfacial tension test (IFT), acidity, moisture content, dielectric strength, and power factor insulation tests also indicate condition of the transformer.

The maintenance history provided by PG&E shows catastrophic failure of bank 2 “B” phase in 1997 due to fire and transformer explosion, cooler leaks of bank 1 “A &B” IN 2005, heat exchanger leak of bank 2 “A & C” phase in 2004 & 2006, and bank 3 “A” phase bushing replacement in 2017. It also indicates the transformers have been regularly tested and DGA analyzed, and no abnormal test results were detected. There were additional minor repairs to resolve oil and water leaks, and bushings were replaced recently.

The transformers may require frequent maintenance in coming years that would cause unplanned outages. They will also have a higher chance of failure due to their 38 years in operation.

It is assumed that the transformers are performing adequately and meet the original design criteria but are likely less efficient and effective than when originally installed.

It is assumed that the physical deterioration for these transformers is more than cosmetic but has not yet compromised physical/structural integrity.

Uprate Limits

The proposed uprate to 460 MW / 506 MVA represents a 15% increase from the existing operating limits. The existing transformers are operating at near capacity at Helms with only a 5 MVA margin leaving it 66 MVA below the desired rating. The thermal dissipation required for a 15% uprate may be feasible with additional cooling, however the transformers present condition should be evaluated for being able to handle the additional load. The transformers most recent test reports should be provided and evaluated, however since the transformers are nearing their expected service life, it is recommended that they should be replaced.

3.6 DISCONNECT SWITCHES, ISO PHASE BUS, AND EXCITER BUS

3.6.1 High Resistance Neutral Grounding Equipment

Estimate of Current Equipment Condition:	Good Condition (Evaluation Proposed)
Existing Capacity:	≥ 404 MW
Uprate Constraint:	≥ 460 MW

The neutral leads of each motor-generator unit are connected to high resistance neutral grounding equipment. The high resistance neutral grounding equipment limits the motor-generator unit's neutral current and trips the motor-generator unit when stator ground fault is detected.

The neutral transformer and secondary resistor combination provides a high resistance ground mitigating the possibility of ferro-resonance and transient overvoltage from switching and arcing. The zero-sequence capacitive reactance and the short-time overload factor are the two driving factors for determining the size of the neutral transformer and secondary resistor.

The high resistance neutral grounding equipment consists of following components:

The neutral transformer has following ratings and characteristics (Table 3-33):

Table 3-33. Neutral Transformer Characteristics

Item	Rating
Type	Dry-Type
Windings	2 Winding
kVA Rating	75 kVA
High Voltage (HV) Primary	19,900 V
Low Voltage (LV) Secondary	120 V / 240 V
Frequency	60 Hz
Phase	1

The resistor has following ratings and characteristics (Table 3-34):

Table 3-34. Resistor Characteristics

Item	Rating
Type	Punched Steel, Grid Type
Resistance Rating	0.15 Ohm
Rated Duty	1 minute of 819 A

Condition Assessment and Uprate Limit:

- CEATI Report No. T092700-0367-1 states the average expected life for generator neutral grounding equipment is 50 years. The neutral grounding equipment has 12 years of remaining service life.
- There are no repairs documented in the maintenance history, so it is assumed that the neutral grounding equipment is in good condition.
- It is assumed that the neutral grounding equipment is performing adequately and meet the original design criteria.
- It is assumed that the physical deterioration for the neutral grounding equipment is more than cosmetic but has not yet compromised physical/structural integrity.
- For unit uprate, a zero-sequence capacitive reactance and the short-time overload factor will be evaluated to determine the size of the neutral transformer and secondary resistor.

3.6.2 Exciter

Each motor-generator unit is equipped with static excitation system to control the voltage and reactive vars of the motor-generator.

The characteristics and ratings of existing motor-generator unit are shown below (Table 3-35):

Table 3-35. Motor - Generator Unit Ratings

Item	Rating	
	(GE Report)	(Unit 3 Exciter 2008 Commissioning Report)
Maximum Apparent Power	448 MVA (Generator)	450 MVA
	385.7 MVA (Motor)	
Armature Voltage	18 kV	18 kV
Power Factor	0.9	0.9
Speed	360 RPM	360 RPM
Field Current, If	-	1,521.4 A (No-load)
	2,540 A (Generator)	2,660 A (Rated)
	2,340 A (Motor)	-
	-	3,990 A (Ceiling)
Excitation System Rated Continuous DC Current	-	2,948 A
Field Voltage, Vf	220 V (Generator)	214 V (Rated)
	202 V (Motor)	-
	-	380V (Ceiling)
Maximum Temperature Rise (Rotor)	80 Degree C	-
Maximum Cooling Air Temperature	40 Degree C	-

The excitation system of each unit is a fully redundant dual channel control system with redundant power converters, and it consists of following equipment:

3.6.2.1 Power Potential Transformer (PPT)

Estimate of Current Equipment Condition:	Moderate Condition (Replacement Proposed)
Existing Capacity:	≥ 404 MW
Uprate Constraint:	≥ 460 MW

The PPT supplies power to the excitation system from the motor-generator main leads through the respective unit's motor starting transformer and 13.8 kV station service switchgear breaker 52ET.

The ratings and characteristics of the PPT are shown in the table below (Table 3-36):

Table 3-36. PPT Characteristics

Item	Rating	
Windings	2 Winding	
kVA Rating	2,000 kVA	
High Voltage (HV) Primary	13,800 V delta	
Low Voltage (LV) Secondary	480 V delta	
Frequency	60 Hz	
Phase	3	
Coolant	Mineral Oil	
Cooling Type	Oil Natural Air Natural (ONAN)	
Winding BIL HV	110 kV	
Bushing Current Transformers HV	**Qty/Bushing** 1	**Ratio** 600/5 MR

<u>Condition Assessment and Uprate Limit:</u>

The PPTs are original equipment installed in 1985 and have been in service for 38 years. The expected service life of a transformer based on the CEATI Report No. T092700-0367-1 is 35 years.

The maintenance history provided by PG&E shows normal preventive maintenance performed on these PPTs. There are no major repairs documented in the maintenance history other than minor repairs to resolve high oil temperature and low oil level alarms. The PPTs may require frequent maintenance in coming years that would cause unplanned outages.

It is assumed that the PPTs are performing adequately and meet the original design criteria but less efficient and effective than when originally installed.

It is assumed that the physical deterioration for these PPTs is more than cosmetic but has not yet compromised physical/structural integrity.

The existing PPT capacity is not sufficient to support power required by the excitation system for higher field current required by uprated unit. Regardless of the alternative selected for future work, the PPT should be replaced with dry-type and installed on main floor or generator floor to create space required for installation of a new motor-generator breaker between the phase reversal switch and GSU transformer of each unit in the respective unit's equipment tunnel between the powerhouse main floor and GSU transformers chamber.

3.6.2.2 Excitation Switchgear

Estimate of Current Equipment Condition:	Good Condition (Evaluation Proposed)
Existing Capacity:	≥404 MW
Uprate Constraint:	≥ 460 MW

The excitation switchgear is a NEMA 1 metal-enclosed cubicle of five vertical sections. The excitation switchgear for units 2 and 3 was replaced in 2007 and unit 1 was replaced in 2009.

The excitation system ratings and characteristics are shown in table below (Table 3-37):

Table 3-37. Excitation System Ratings

Characteristic	Rating
Type	Static
Rated Continuous DC Current	2,948 ADC
Ceiling Voltage	380 VDC
Converter Supply Voltage	480 VAC
Converter Supply Frequency	60 Hz
Max Ambient Temperature	40 °C

Looking from the front and starting with the right-side section 1 and moving to the sections 2 to 5 on the left, the sections are as follows:

Automatic Voltage Regulator Cubicle

This cubicle houses redundant controllers (ABB Unitrol 5000), operator display and control panel, and power, control and indicating devices. The minimum and maximum excitation limiters, volts/hertz limiter, power system stabilizer, and accelerator torque stabilizer parameters are programmed in the controllers.

AC Connection & Field Flashing Cubicle

This cubicle houses manual transfer switch for 480V ac power to the power converters and excitation system auxiliaries, ac power fuses and auxiliary devices, and field flashing circuit breaker. The manual transfer switch provides means for selecting between normal 480V source, emergency 480V source and off positions.

Bridge 2 Cubicle

This cubicle houses one of two power converters, converter’s thyristor firing modules, and cooling equipment. The power converter is rated 3,200 amperes and has sufficient capacity to provide all the field current to the unit. Only one converter is in operation (on-line) at a time. Failure of the on-line converter will switch the stand-by converter to take over field current supply to the unit.

Bridge 1 Cubicle

Same as Bridge 2 Cubicle

DC Field Breaker, DC Bus Termination, & De-Excitation (Field Suppression) Cubicle

This cubicle houses dc field breaker used for supplying dc field current output from the power converter to the unit. The dc field breaker also provides means to isolate power converter dc field output to the unit during unit tripping or shutdown and allowing the de-excitation system to start and dissipate all residual energy from the unit through field suppression equipment installed in this cubicle.

Condition Assessment and Uprate Limit:

The expected service life of the excitation system based on the CEATI Report No. T092700-0367-1 is 30 years. The excitation switchgear was replaced in 2007 and 2009 so it has more than 14 years of remaining service life.

The operation and maintenance history provided by PG&E shows rare corrective maintenance performed on the excitation switchgear power and control circuit components. Therefore, it is assumed that the operation and maintenance for the excitation switchgear are normal.

Stantec recommends a complete inventory of the spare parts should be taken and new spare parts ordered now to reduce outage time in future. Hardware and software for digital control system have a short life span and they become obsolete over time, so it is important to have spare hardware readily available and manufacturer's support for software to reduce outage time and keep the excitation system in operation in future.

The existing excitation system has the capacity for supplying the required field current for uprated unit, however it is recommended to have this confirmed by the manufacturer of the excitation system.

3.6.3 Starting Equipment

The starting equipment consists of starting motor, 5 kV bus and equipment, starting motor selector switches, liquid rheostats, liquid rheostat selector switches, and control equipment.

3.6.3.1 Starting Motor

Estimate of Current Equipment Condition:	Moderate Condition (Refurbishment Recommended)
Existing Capacity:	≥ 404 MW
Uprate Constraint:	≥ 460 MW

The starting motor is a wound rotor induction motor, vertical engine type design, totally enclosed and forced ventilated by an external fan. It is mounted on the motor-generator unit and used to bring the unit up to speed during the pumping mode. A liquid rheostat is connected across the rotor slip rings to provide speed control during acceleration and synchronization.

For starting motor frame, stator core, rotor core, stator coil, rotor coil, and spider details, refer to Westinghouse O&M manual.

The starting motor, based on the manufacturer's data sheet, has the following ratings and characteristics (Table 3-38):

Table 3-38. Starting Motor Ratings

Item		Rating & Characteristic
Base Capacity		17,000 HP
Duty		Intermittent
Type		Wound Rotor
Poles		18
Synchronous Speed		400 RPM
Frequency		60 Hz
Stator (Primary) Line Voltage		13,200 V
Stator Line Current at Rated Power and Voltage		744 A
Stator Winding Connection		3 Phase, 6 Parallel Wye
Rotor (Secondary) Ring Voltage		3,967 V
Rotor Ring Current at Rated Power and Voltage		1,946 A
Rotor Winding Connection		3 Phase, Series Delta
Resistance & Reactance on 12,682 kW Base, 13,200 V Base	Stator (Primary) Leakage Reactance	0.1074 p.u.
	Rotor (Secondary) Leakage Reactance	0.1042 p.u.
	Magnetizing Reactance	1.578 p.u.
	Stator Internal Resistance	0.00395 p.u.
	Rotor Internal Resistance	0.00429 p.u.
	Transient Reactance (Unsaturated)	0.2047 p.u.
	Stator Resistance at 95 °C Between Lines	0.1086 ohms
	Stator Resistance at 95 °C Per Phase	0.0543 ohms
	Rotor Resistance at 95 °C Between Rings	0.01215 ohms
	Rotor Resistance at 95 °C Per Phase	0.01822 ohms

Item		Rating & Characteristic	
	Turns Ratio, Primary to Secondary	1.798 ohms	
	100% External Secondary Resistance Per Phase Wye	1.139 ohms	
Current Transformers	**For**	**Qty:**	**Ratio**
	Stator Neutral	3	1,200/5 SR
	Stator Line Leads	1	1,200/5 SR
	Rotor	3	3,000/5 SR

Condition Assessment and Uprate Limit:

CEATI Report No. T092700-0367-1 states the average expected life for a large motor stator coil is between 25 to 35 years and rotor coil is between 50 to 60 years. The age of large motor stator and rotor coils is an important factor to consider when the coils should be replaced, however it is also important to consider the operation and maintenance history of motor, as it provides a useful indication of motor's stator and rotor condition. Factors for operations and maintenance to be considered are as follows:

1. Maintenance needs are increasing with time or problems are re-occurring: There are no records showing frequent maintenance or re-occurring problems for starting motors causing unplanned outages, so this factor is not considered in the condition assessment.

Spare parts are becoming unavailable: It is assumed that spare parts are readily available for future maintenance. Stantec recommends an inventory of spare parts is taken and new spare parts are procured for future maintenance.

Operating outside of voltage rating (either higher or lower): There are no overvoltage or undervoltage alarms reported in the maintenance history, so it is assumed the motor is always operating at its voltage rating. This factor is not considered in the condition assessment.

Sustained overloading: There are no motor overload alarms reported in the maintenance history, so it is assumed the motor is always operating at its normal rating. This factor is not considered in the condition assessment.

Previous failures related to stator, rotor, or coils: The maintenance history indicates that the starting motor's stator and rotor have been regularly inspected and tested. Unit 3 starting motor stator was repaired in 2015. Units 1 and 2 starting motor stators were re-wedged in 2015 and 2019, respectively.

Based on the above factors and age of the stator and rotor coils, it is recommended that the stator coils be replaced to extend the service life of the starting motor to another 40 years.

3.6.3.2 5 kV Starting Bus

Estimate of Current Equipment Condition:	Good Condition (Re-use Proposed)
Existing Capacity:	≥ 404 MW
Uprate Constraint:	≥ 460 MW

The 5 kV starting bus connects the liquid rheostats with the starting motor rotor of each motor-generator unit through the liquid rheostat selector switch and starting motor selector switch.

The starting bus is 3-phase insulated (copper or aluminum bar) non-segregated phase duct and rated as follows (Table 3-39):

Table 3-39. Starting Bus Ratings

Item	Ratings
Nominal Operating Voltage	4.76 kV
Maximum Bus Voltage	5 kV
Basic Insulation Level (BIL)	75 kV
Rated Continuous Current	3,000 Amps
Rated Momentary Withstand Current (peak, 10 cycle)	70 kA
Power frequency withstand voltage (dry, 1 min)	19 kV rms

Condition Assessment and Uprate Limit:

The bus is the original equipment installed in 1985 and has been in service for 38 years. The expected service life of a medium voltage bus based on the CEATI Report No. T092700-0367-1 is 40 years. The maximum continuous current the bus will be carrying at any given time is 1,946A, and for a short time an inrush current of approximately 6 times the full load current during pony motor start-up. The bus is rated at 3,000A, so the bus should have ample of capacity to support higher loads and remaining service life than the expected service life indicated in the CEATI report as the bus has been loaded much less than its nominal rating and has never been operated under overload conditions.

The maintenance history provided by PG&E shows normal preventive maintenance performed on the bus. There are no major repairs documented in the maintenance history and the bus has never been operated in overload conditions, so it is assumed the bus is adequate for reuse.

Operational performance for the bus is assumed to be normal and meet the original design criteria.

It is assumed that the bus has no physical deterioration.

3.6.3.3 Starting Motor Selector Switches

Estimate of Current Equipment Condition:	Good Condition (Re-use Proposed)
Existing Capacity:	≥ 404 MW
Uprate Constraint:	≥ 460 MW

The starting motor selector switch connects the 5 kV starting bus to the starting motor rotor of each motor-generator unit. There are three starting motor selector switches.

The ratings and characteristics of each starting motor selector switch are shown in Table 3-40 below:

Table 3-40. Motor Selector Switch Ratings

Item	Ratings
Switchgear Type	Metal Enclosed
Number of Phases	3
Number of Poles per Switch	2
Nominal Operating Voltage	4.76 kV
Maximum Operating Voltage	5 kV
Basic Insulation Level (BIL)	75 kV
Rated Continuous Current	3,000 A
Rated Short Time Withstand Current	80 kA
Type of Operating Mechanism	Motor Operated
Operating Voltage for Motor Operator	208 VAC, 3-Phase

<u>Condition Assessment and Uprate Limit:</u>

Starting motor selector switches are original equipment and have been in service for 38 years. The expected service life of a medium voltage switch based on the CEATI Report No. T092700-0367-1 is 35 years. The maximum continuous current the switches will be carrying at any given time is 1,946A, and for a short time an inrush current of approximately 6 times the full load current during pony motor start-up. The switch is rated at 3,000A, so it should have ample of capacity to support higher loads and remaining service life than the expected service life indicated in the CEATI report.

The maintenance history provided by PG&E shows normal preventive maintenance performed on the switches. There are no major repairs documented in the maintenance history and the switches have never been operated in overload conditions, so it is assumed the switches are adequate for reuse.

Operational performance for the switches is assumed to be normal and meets the original design criteria.

It is assumed that the switches have no physical deterioration.

3.6.3.4 Liquid Rheostat

Estimate of Current Equipment Condition:	Good Condition (Evaluation Proposed)
Existing Capacity:	≥ 460 MW
Uprate Constraint:	≥ 460 MW

Liquid rheostat is used to control the speed of the starting motor during the pump mode start-up of the motor-generator unit and to bring the motor-generator unit from standstill to synchronous speed within 10 minutes. The resistance of the rheostat is changed by controlling the position and speed of movable electrodes by a controller in the Control Panel. There are two liquid rheostats, and each rheostat is connected to the 5 kV starting bus through its selector switch. One rheostat is connected to the 5 kV starting bus at a time to control the speed of the starting motor.

Each of the two liquid rheostats A and B consists of three parts:

Rheostat A:

A large electrolyte filled tank with three insulated cells containing the stationary and movable electrodes, and pilot motor and solenoid valves to control the speed and position of the electrodes.

A heat exchanger removes heat generated in the electrolyte between the electrodes during operation.

A control panel with controller, and control and indicating devices for controls of speed and position of electrodes.

Rheostat B:

Two electrolyte tanks each with three insulated cells containing the stationary and movable electrodes, and a drive unit.

Two heat exchangers, each operated by a pump motor, for removing heat generated in the electrolyte between the electrodes during operation.

A control panel with controller, and control and indicating devices for controls of speed and position of electrodes through the drive units.

The ratings and characteristics of the liquid rheostat B are as follows (Table 3-41):

Table 3-41. Liquid Rheostat B ratings

Item	Ratings
Starting Gravity, f	1
Starting Current Limit, IRotor	2,606 A ± 10%
Max Resistance	1.58 Ohm
Conductance of Electrolyte at 25°C	2.98 mS/cm
Amount of Water	6,900 l
Weight of NA2CO3 in %	0.22 %
Weight of NA2CO3 in kg	2 x 6 kg

Condition Assessment and Uprate Limit

Liquid rheostat A is original equipment and has been in service for 38 years. Liquid rheostat B was installed in 2015 as a backup to the liquid rheostat A. The expected service life of liquid rheostat is 20 years.

The maintenance history provided by PG&E shows normal preventive maintenance performed on the rheostats. There are no major repairs documented in the maintenance history and the rheostats have never been operated in overload conditions, so it is assumed the rheostats are adequate for reuse.

Operational performance for the rheostats is assumed to be normal and meets the original design criteria.

It is assumed that the rheostats have no physical deterioration.

The increase in pony motor load for uprated unit is assumed to be less than 5%. The starting current limit and maximum resistance of the liquid rheostat is 2,606 A and 1.58 ohms, respectively. The maximum continuous current of pony motor rotor for operation with uprated unit is approximately 2,050A at 3,967V. The liquid rheostat has the capacity to control the speed of the starting motor during the pump mode start-up of uprated motor-generator unit and may be able to bring the motor-generator unit from standstill to synchronous speed within 10 minutes. Stantec recommends the size of the liquid rheostat should be evaluated after starting motor rating is determined for operation with uprated unit.

3.6.3.5 Liquid Rheostat Selector Switches

The liquid rheostat selector switch connects the 5 kV starting bus to the liquid rheostat. There are two liquid rheostat selector switches, one for each liquid rheostat. Engineering assessment for Starting Motor Selector Switches apply to the Liquid Rheostat Selector Switches.

3.6.4 20 kV Bus & Auxiliary Devices

Refer to Isolated Phase Bus and Phase Reversal Switch engineering assessment.

3.6.5 Isolated Phase Bus

Estimate of Current Equipment Condition:	Good Condition (Replacement Proposed)
Existing Capacity:	404 MW
Uprate Constraint:	≥ 460 MW

The 23 kV isolated phase bus interconnects the motor-generator unit with the main bank transformers and the starting motor transformer. The isolated phase bus acts to transmit power to and from the motor-generator units at 18 kV.

An associated potential transformer and surge protection cubicle measures 23 kV bus potential for protection, excitation feedback and metering purposes and protects the generator-motor against power surges.

There are two sets of three phase draw-out type potential transformers. The potential transformers are two windings and have a voltage rating of 18,000-120V. Each transformer is protected with primary and secondary fuses.

The generator surge protection equipment consists of one gapless metal oxide station type surge arrester and standard station type surge capacitor per phase.

The ratings and characteristics of the isolated phase bus duct are as follows (Table 3-42):

Table 3-42. Isolated Phase Bus Ratings

Item	Ratings
Type	Self-Cooled, No-Flux Design
Number of Phases	3
Nominal Operating Voltage	18 kV
Maximum Operating Voltage	23 kV
Rated Continuous Current	15,000 A

Condition Assessment and Uprate Limit:

Isolated phase bus, and potential transformers and surge protection equipment are original equipment and have been in service for 38 years. The expected service life of Isolated phase bus based on the CEATI Report No. T092700-0367-1 is 40 years. The expected service life of potential transformers and surge protection equipment is more than 40 years.

The maintenance history provided by PG&E shows normal preventive maintenance performed on the isolated phase bus duct. There are no major repairs documented in the maintenance history and the bus has never been operated in overload conditions, so it is assumed the bus is adequate for reuse. It is assumed that the potential transformers and surge protection equipment are regularly tested to check their condition.

Operational performance for the isolated phase bus duct, and potential transformers and surge protection equipment is assumed to be normal and meet the original design criteria.

It is assumed that the isolated phase bus duct, and potential transformers and surge protection equipment have no physical deterioration.

The maximum rating of existing isolated phase bus is 404 MW (448 MVA at 0.9 power factor) so it will have to be replaced for uprated unit.

3.6.6 Phase Reversing Switch

Estimate of Current Equipment Condition:	Good Condition (Replacement Proposed)
Existing Capacity:	404 MW
Uprate Constraint:	≥ 460 MW

The five-pole phase reversing switch serves to reverse the phasing of the isolated phase bus into the motor-generator for operation as a generator or as a motor and to disconnect motor-generator from the main bank transformers. In generate position, poles 1, 3 and 5 are closed to arrange the phasing CBA (looking left-to-right from motor-generator terminals towards the main bank transformers). In pump mode, poles 2, 4 and 5 are closed to arrange phasing BCA.

The phase reversing switch has no interrupting capability and cannot change positions when carrying load. The operating time of phase reversing switch is 15 seconds when changing position from pump to generator and vice-a-versa. The ratings and characteristics of the phase reversing switch are as follows (Table 3-43):

Table 3-43. Phase Reversing Switch Ratings

Item	Ratings
Number of Poles	5
Nominal Operating Voltage	18 kV
Maximum Operating Voltage	23 kV
Rated Continuous Current	15,000 A
Type of Switch Operator	125VDC Motor Operator

<u>Condition Assessment and Uprate Limit:</u>

Phase reversing switches are original equipment and have been in service for 38 years. Units 1 and 2 phase reversing switches were refurbished in 2014 and unit 3 phase reversing switch was refurbished in 2013. The gearboxes, coils, control devices, blade contacts of switches have been frequently serviced and repaired. The expected service life of phase reversing switch based on the CEATI Report No. T092700-0367-1 is 35 years.

The maximum rating of existing phase reversing switches is 404 MW (448 MVA at 0.9 power factor) so they will have to be replaced for uprated unit.

3.6.7 Generator/Motor Circuit Breakers

There is no motor-generator breaker between the motor-generator unit and main bank transformer. The motor-generator is synchronized through a 230 kV switchyard breaker. It is recommended to install a motor-generator breaker between each motor-generator unit and its respective main bank transformer. The motor-generator circuit breaker will increase the reliability (protection of generator against system fed fault currents and step-up transformer against generator fed fault currents) and availability of pony motor for dynamic braking during generator shutdown, and power to station service equipment (keep 230 kV switchyard unit breaker closed). The layout of isolated phase bus will have to be configured for installation of the motor-generator circuit breaker (refer to isolated phase bus engineering assessment).

3.7 BALANCE OF PLANT (MECHANICAL)

The Helms plant is nearly 40 years old with many of its balance of plant systems approaching the limits of their planned service life. With that said, however, a simple “replace everything approach” is not likely the correct action plan for PG&E. Refurbishment or replacement of the balance of plant (BOP) systems at Helms should be based on their current and projected condition, known operational issues, their statistical service life expectation and the components or systems predicted mean time between failure. This way the desired future equipment and overall plant operability and reliability for the desired 40-year life extension can be engineered into a long-term asset management plan, with refurbishment and replacement investments and their associated outages done cost-effectively and efficiently.

For Helms, the BOP systems and their equipment should be assessed with operational experience input (use and deviation from design info), asset management input *(age and opportune financial replacement opportunities)*, and preventative, predictive, and/or reliability-centered maintenance *(condition assessment and statistical engineering)* techniques applied. Usually, during major unit upgrades or overhauls some of the BOP equipment is worked on as small capital investment projects or worked on under a large unit overhaul or upgrade budget, often coincident with the unit uprate or overhaul itself. For both approaches limited defined boundaries of work for each system should be done with effort to define the connection and requirements needed to coordinate the BOP refurbishments and replacements with the turbine, generator, transformer, auto-control contractors, and gate OEMs.

If the BOP equipment is near end-of-life, then repairs, modifications, or replacements during major unit overhauls can make sense in terms of efficiency for outages. Sometimes the BOP will need to be upgraded or modified with the unit overhauls depending on design changes such as flow, pressure, or because of modified design needed to meet new unit requirements. Other reasons include insurance compliance or building standard improvements.

As such, the interface between the BOP and the new units and their peripheral equipment will require planned coordination once the major alternatives analysis is completed, and the unit planning is set into motion. The long-term asset management of the plant’s BOP systems will need to be planned, with requirements to support the unit uprate and life extension, optimization and economics being the deciding factors in selecting BOP work.

Typically, the pump-turbine manufacturer will set up a boundary of work for refurbishment at the pump-turbine pit boundaries, or where the balance of plant piping meets with the motor-generator and pump-turbine. For the main GSU OEM, the boundary is usually at the civil installation of the transformer itself, and at the power cables and auto control terminations. This can vary.

When preparing for the outage, the final conforming contract for the pump-turbine supplier, motor-generator supplier, controls work, and transformer work will need to be written to explicitly define the boundaries of work with the existing BOP systems while requiring the OEMs to either adapt to them or to take ownership of some systems and BOP modifications needed.

Although the focus of current efforts is the unit powertrains and direct auxiliaries, below (Table 3-44) are mechanical BOP Systems that will need consideration as part of the overall uprate and life extension and should be later fed into the project's overall scope.

Table 3-44. Summary of Typical Mechanical BOP Assessment Work Scope Items

System:	Pre-Project Outage Scope of Work:
Depression Air System	Perform a condition assessment on the depression air system components. Identify reliability issues and long lead items to prepare for project outage testing requirements. Benchmark charging time. Investigate charging times for the system to determine if inefficiencies have arisen over the years. Record the time it takes to recharge the depression air receiver tanks and compare it to past records to see if leakage is an issue.
Pump-Turbine and Motor-Generator Cooling Water Systems	Assessment should be done on the existing cooling water pipes, pipe supports, cooling water supply pumps, cooling water pump motors, motor control centers (MCC), their control system (RTUs where applicable), and on the sump pits and filtration systems (i.e., clean water supply to thrust bearing pads, generator stator, shaft seal, etc.)
Generator-Motor CO2 Fire Suppression System	Project consultation should be made to be done with: the plant operations, occupational health and safety group, the owners fire protection engineering, asset management, and finally with the generator OEM and insurance. Condition assessment of the system should be done, and a decision on what to do with the system should be worked into the project schedule and planning. A design basis document should be developed in accordance with NFPA 850 to identify hazards and provide a basis for decision-making. Removal of the old system should be considered, with replacement. A phased approach may be necessary to replace one generator unit at a time.
Main Transformer Bank / Isophase Bus Fire Protection System	Condition Assessment and consultation with plant operations to determine if there are any issues with the plant. Discussions with the owner's fire protection engineering representative, plant operations, and insurance to determine if the system merits a capital investment or any significant modifications to be done in coordination with the plant outages. Speak with transformer designers, and isophase designers to determine if they have any recommended changes to equipment from lessons learned or internal and external standards improvements since the original design.
230 KV Cable Fire Protection	A condition assessment of the check valves and isolation valves should be done, with replacement or refurbishment planned prior to the outage. Ensuring the

(Powerhouse Cable Tunnel, Elevator Shaft and Switchyard)	valves and piping systems can be isolated, inspected, and repaired without interfering in the unit outage is the goal. Assessment of the piping, and testing or confirmation that piping flange gaskets, insulation, and paint are not hazardous materials (asbestos materials, and lead paint) should be done as pre-outage preparation work.

3.7.1 Depression Air System

Estimate of Current Equipment Condition:	Moderate Condition (Further evaluation proposed)
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

The draft tube water depression system is used to displace draft tube water out of the upper draft tube cone to allow the turbine-runner to spin in air, and to thus achieve synchronous pumping speed via torque from the pony motor. Synchronous condensing operations also use this system when the machine is spinning in air, in synchronous condense mode, and it is used when the unit is in standby, spinning in air mode.

A summary of the components of the system are described below.

Air Compressors

The system uses three air compressors to provide pressurized air to the Air Receiver Tanks. The compressors are a two-stage rotary screw-type design and were originally supplied by the Sullair Company. They are housed in the compressor area of the plant.

The compressors are two-stage rotary screw type design and were originally supplied by the Sullair Company. They are housed in the compressor area of the plant.

Together, the three compressors can recharge the receiver tanks in 6 to 17 minutes after the depression of pump-turbine operation. (At 235 psi). *(The reason for the varied time depends on tailwater elevation, i.e., back pressure)* The compressors are rated at 500 SCFM at 250 psi output pressure.

Compressor maintenance is important for ensuring reliability of operations and for achieving efficient charging times of the air receiver tanks. Replacement or intrusive maintenance of the compressors could be considered during an overhaul or unit upgrade however this may not be needed.

Air Receiver Tanks

There are a total of 3 air receiver tanks with each tank having a capacity of 1,760 cubic feet. The receiver's system's total volume is listed as 5,580 cubic feet in the PG&E Description of Operations Manual. The system appears to have been originally designed so that one pump-turbine depression operation could be done without engaging the compressors.

Over time leakages along piping and valve trim can create small taxes on the receiver system with more frequent top-offs of the air required on some plants. The operational history and daily run time of the compressors should be assessed to determine the extent of leakage losses on the system. If losses have increased over the years, or if the operational run time of the compressors has increased notably, then the system should be considered for deeper assessment and possible intervention. *(Mean times between maintenance can increase from added wear from additional run time needed to maintain the depression air pressure.)*

Valves and Piping

Even though the system uses typical isolation valves and piping the check valves, and isolation valves and their actuators are very important because they must prevent reverse flows and air leakages which can create issues such as inadvertently depressing the turbine’s draft tube during standstill if air is permitted to leak into it.

Depression Water Sensor System

This system is used to detect the water level in the upper draft tube. It is critical that the sensors and piping work well to ensure that there are no issues with excessive or errant depression. Also, unintended leakages from the air system into the draft tube have on other plants caused the draft tube to be depressed unintentionally. A scenario like this can be very dangerous to the unit and worker safety if the unit is called into generate mode with the draft tube depressed.

Future pre-design activities for this system include:

- Perform a detailed condition assessment on the compressors, tanks (internal corrosion) and valves (Leakages or actuator issues). For the compressors record their pressure output, and settings, and also check their historic operational run time logs (and hour counter) to see if the compressors are operating more due to potential leaks. Identify reliability issues and long lead items to prepare for project outage testing requirements.
- Investigate charging times for the system to determine if inefficiencies have arisen over the years. Record the time it takes to recharge the depression air receiver tanks and compare it to past records to see if leakage is an issue. Benchmark charging time characteristics with compressor run time.

3.7.2 Cooling Water System

Estimate of Current Equipment Condition:	**Moderate Condition (Replacement Proposed)**
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

The plant’s cooling water system serves the motor-generator, pump-turbine, transformers, excitation system, and ties into the fire protection system. A traditional condition assessment on the system should be done prior to any uprate or overhaul outage so that any correct actions, repairs, and modification to integrate to a new or uprated unit can be done.

Cooling water is drawn from the lower reservoir through inlets in each unit's draft tube, with pressures boosted by cooling water pumps. In total there are 7 cooling water pumps. Pumps 1 to 3 are the main unit pumps, with pump 4 being a standby pump (Pumps 1 to 4 are rated at 2,500 gpm, at 135-foot dynamic head), and pumps 5 to 7 being designated auxiliary pumps (rated at 1,500 gpm, at 135-foot dynamic head). These pumps are horizontal split case, double suction design, and are powered by 100 HP and 60 HP (respectively) three phase 480 VAC motors.

Plant personnel have reported some cooling water system issues, understood mostly due to the aging conveyance system (i.e., pump condition, aging/corroded piping with reduced cross sections). We understand bearing temperatures consistently run towards the alarm settings, but issues become more prevalent when at lower Wishon reservoir levels (lower supply pressure), or when cooling water supply is warmer.

For the sub systems for cooling water relating to the thrust bearing, pump-turbine runner crown and band seals, bearings and motor-generator cooling please refer to the pump-turbine section.

Future pre-design activities for this system include:

Detailed assessment should be done on the existing cooling water pipes, pipe supports, cooling water supply pumps, cooling water pump motors, motor control centers (MCC), their control system (RTUs where applicable), and on the sump pits and filtration systems (i.e., clean water supply to thrust bearing pads, generator stator, shaft seal, etc.)

3.7.3 Lubricating Oil System

Estimate of Current Equipment Condition:	Moderate Condition (Refurbishment Proposed)
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

The plant has a lubricating and insulating oil storage tank system and tank area inside the plant. During periodic long-term maintenance, an overhaul or a unit upgrade, a hydraulic power system or lubricating oil system may require flushing and cleaning to be able to meet the equipment manufacturer's warranties for hydraulic system or bearing installation.

It is a common practice that the oil for the hydraulic system or bearings will have a cleanliness specification which the manufacturer will require the plant to obtain and demonstrate with testing for warranting the bearings. Replacement or uprated unit bearings and hydraulic systems may require more stringent cleanliness requirements. In any case, cleaning and flushing of the plants' oil systems and common piping is required as part of an upgrade or overhaul, to be done in close coordination with the overall project.

3.7.4 Plant Drainage System

Estimate of Current Equipment Condition:	Moderate Condition (Further evaluation proposed)
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

Plant drainage systems are often addressed as part of pump-turbine overhauls or unit upgrades regarding head cover drainage, and for deluge drainage in case fire suppression systems are altered.

For the turbine, the shaft seal leakage rate (Clean water which is piped to the seal interface that drains to the headcover) might be increased if a new seal design is implemented and as such the total drainage capacity should be addressed with any additional drainage burdens identified also which might have been added since original construction.

3.7.5 Unwatering System

Estimate of Current Equipment Condition:	Moderate Condition (Further evaluation proposed)
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

The unwatering pumps and sump control system should be assessed prior to undertaking overhauls or unit upgrades mainly to ensure prevention of any unnecessary delays or issues when dewatering the unit.

If the Volume of the draft tube is changed as part of a unit upgrade or overhaul, then the sump pumps flow rate and piping diameters may need to be assessed against the new volume.

3.7.6 Fire Protection Systems

Estimate of Current Equipment Condition:	Moderate Condition (Replacement Proposed)
Existing Capacity:	460 MW
Uprate Constraint:	≥ 460 MW

<u>Codes and Standards</u>

NFPA 850 Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations outlines the practice for fire safety recommendations for gas, oil, coal, and hydroelectric generating plants. Note, NFPA 851 Recommended Practice for Fire Protection for Hydroelectric Generating Plants was withdrawn in 2014 and material incorporated into NFPA 850. This standard provides fire prevention and fire protection recommendations for hydroelectric generating plants to safeguard personnel, protect physical property, ensure continuity of power production, and

control the impact of fire and fire-fighting activities on the environment. This document says the selection of an extinguishing agent should be based on the following: type of hazard, effect of agent discharge on equipment, and health hazards.

Generator – Motors

The Helms plant was originally equipped with two redundant CO_2 fire suppression systems for the generators, each one has a main system and reserve system. The generator housing is flooded with the main CO_2 bank to create an inert atmosphere to extinguish the fire. The reserve release is delayed maintaining concentration in the enclosure until the generator stops. Each system was designed with bottled storage (quantity x 36, 75-pound bottles), rather than a large singular tank or reservoir. A bottled system has the advantage of easier maintainability in terms of leak detection despite the manifold having more piping. Annual maintenance requires each bottle to be weighed to confirm they are filled and do not leak.

Recently many hydro utilities have been retiring their CO_2 fire suppression systems due to obsolescence of parts and risks carried with maintaining active systems. CO2 systems present risk of worker death if the system is activated (either errantly or by human error). Workers conducting work in zones that the systems feed are always at some risk despite lock-out tag-out measures or even redundant sensors. CO_2 systems have been known to have caused the deaths of workers from errant operations, human error, and from simple leakages. Because of this many utilities are moving away from CO_2 systems to other systems such Intergen, or even to water nano mist or water deluge systems and more recently hybrid nitrogen/water mist systems.

The Helms CO2 fire suppression system is at risk for parts obsolescence. It is for this reason that replacement should be considered. Remaining life may be as much as 10-years or less.

Future pre-design activities for this subsystem include:

1. Project consultation should be made to be done with the plant operations, occupational health and safety group, the owners fire protection engineering, asset management, and finally with the generator OEM and insurance.
2. Condition assessment of the system should be done, and a decision on what to do with the system should be worked into the project schedule and planning. A design basis document should be developed in accordance with NFPA 850 to identify hazards and provide a basis for decision-making.
3. Removal of the old system should be considered, with replacement. A phased approach may be necessary to replace one generator unit at a time.

Main Transformer Bank / Isophase Bus Protection

The plant also has a water spray system for the main transformer bank and isophase bus protection system. (Automatic timed water spray, with dry pipes while not in action) Dry pipe systems have been known to experience corrosion despite not being filled with water, and in some cases loose steel or debris can cause clogs in sprinklers.

The system is likely to be in good condition and could remain in service for more than 20- years with regular maintenance.

It is recommended that regular preventative maintenance plans include testing and replacement of sprinkler heads as necessary for main transformers. (Spraying and testing of the isophase bus however requires careful planning in that the insulators need to be clean of debris or residue so that they can function per design, and the ducts conductors in general should be dry and free of particulate with connections not permitted to corrode, etc.)

Deluge valves often require maintenance and testing of the actuator system and of the valve itself. The ability to reset the deluge valve after being activated is important for underground plants if the control system malfunctions. The plant operation department should be consulted as part of a condition assessment of the transformer / isophase spray systems to determine if there are any issues with the system operations or equipment prior to considering an upgrade. Isolation of individual transformers as part of any project work will need to be worked into the project planning phase, along with their fire protection systems. When putting a fire protection system out of service for long periods of time (Outside simple maintenance or testing periods) the owner should consider consulting their fire protection engineers, and insurance company also to inform them of any long duration outages.

Future pre-design activities for this subsystem include:

1. Detailed condition assessment and consultation with plant operations to determine if there are any issues with the plant.
2. Discussions with PG&E’s fire protection engineering representative, plant operations, and insurance to determine if the system merits a capital investment or any significant modifications to be done in coordination with the plant outages.
3. Speak with transformer designers, and isophase designers to determine if they have any recommended changes to equipment from lessons learned or internal and external standards improvements since the original design.

Oil Handling Room

Protection for the oil handling room comes from the west side of the Main Transformer / Isophase Bus System. Refer to that section for that system assessment. If that system is temporarily put out of service, then an alternative protection plan should be employed should any work to the oil handling room need to be done at the same time.

Fire Protection Water Supply System

The main water supply for the fire protection system is provided from Tunnel 3. The reserve system is fed from T2 with its pressure regulated down. Also, there is a backup system that can be manually valved in from the 30-inch sump discharge header, but this has limited capability.

The water supply system is likely to be in good condition and could remain in service for more than 20-years with regular maintenance. It is recommended that piping and valves be inspected to assess potential corrosion prior to accepting this assessment.

Future pre-design activities for this system include:

1. A detailed condition assessment of the pressure regulator, check valves and isolation valves should be done, with replacement or refurbishment planned prior to the outage. Ensuring the valves and piping systems can be isolated, inspected, and repaired without interfering in the unit outage is the goal.
2. Assessment of the piping, and testing or confirmation that piping flange gaskets, insulation, and paint are not hazardous materials (asbestos materials, and lead paint) should be done as pre-outage preparation work.

230 KV Cable Fire Protection (Powerhouse Cable Tunnel, Elevator Shaft and Switchyard)

There is a wet pipe sprinkler system for fire protection that covers a portion of the 230 KV oil-filled cables in the powerhouse cable tunnel, and a deluge system for the switchyard trench.

Oil filled cables for 230 KV power output was common during the 1970s and 1980s. Recently, in the past decade XLPE or cross-linked polyethylene insulated cables have been installed and used in lieu of oil filled/paper insulated cables on some high voltage (230 KV and 245 KV) generator transformer output voltages. This is because XLPE cables generally have less maintenance issues. XLPE does use an oil-impregnated paper insulation system and does not need to be pressurized or monitored for typical gassing failure or explosive failure modes.

The wetted pipe sprinkler system is likely to be in good condition and could remain in service for more than 20- years with regular maintenance.

Future pre-design activities for this system include:

1. A detailed condition assessment of the check valves and isolation valves should be done, with replacement or refurbishment planned prior to the outage. Ensuring the valves and piping systems can be isolated, inspected, and repaired without interfering in the unit outage is the goal.
2. Assessment of the piping, and testing or confirmation that piping flange gaskets, insulation, and paint are not hazardous materials (asbestos materials, and lead paint) should be done as pre-outage preparation work.

3.8 CIVIL-STRUCTURAL WORKS

Estimate of Current Equipment Condition:	**Good Condition**
Existing Capacity:	≥ 460 MW
Uprate Constraint:	N/A

The Helms Powerhouse Complex was constructed between 1977 and 1982, mostly in hard, sound granite, using drill and blast excavation methods. The Helms Powerhouse Complex connects Courtright

Reservoir and Lake Wishon. The following sections contain engineering assessment for civil-structural components of the Helms Powerhouse Complex.

3.8.1 Powerhouse

The Helms Pumped Storage Powerhouse is in an underground rock chamber at the intersection of Tunnel 2 and Tunnel 3 and the Powerhouse Access Tunnel. The powerhouse rock chamber is located more than 1,100 feet underground. The powerhouse rock chamber is approximately 83 feet wide, 142 feet high, and 336-foot-long excavation. The Powerhouse consists of four separate floors: main floor at Elevation 6,286 feet, generator floor at Elevation 6,264 feet, turbine floor at Elevation 6,250 feet and basement floor at elevation 6,225 feet. The floors are supported by perimeter concrete walls and interior concrete walls.

The transformer chamber is located upstream of the powerhouse rock chamber. It is an approximately 41-foot-wide, 41-foot-high, and 300-foot-long excavation.

Based on available documentation review it is evaluated that the Helms Powerhouse structure can operate for another 50 years.

<u>Powerhouse Crane</u>

The Helms Powerhouse is housing two 270-ton bridge cranes which are connected with a 525-ton lifting beam.

The cranes assessment for lifting capacity for new stator and motor-generator component weights is in PG&E’s scope of work.

Existing crane rails and rail alignment, as well as an existing crane support structure evaluation, are in PG&E’s scope of work as well.

Once new stator and generator component weights are available, it is recommended to perform the existing lay down area floor structural evaluation for increased loads.

<u>Motor-Generators Area</u>

The structural evaluations of existing foundations, for all equipment that require upgrade, will need to be performed.

New foundations will need to be added for any new machine tool foundations needed as part of any local refurbishment such as onsite lathe or cutting equipment.

New compressors may require new mounts or pedestals.

As current studies show that shear stresses on the existing stator foundation dowels exceed the allowable stress limits, it will be necessary to evaluate the increase of existing sole plate pockets for addition of new radial dowels.

The existing powerhouse wall will need to be evaluated for new upper bearing bracket forces particularly in runway or overspeed condition.

In case of isophase bus uprates it will be very likely necessary to replace duct mounting and internal stand of pedestals.

Pump-Turbine Area

Based on performed uprate studies the widening of concrete embedded draft tube sections could be required. It will be necessary to evaluate the concrete around embedded draft tube sections that require widening.

TSV

TSV replacement project, which is currently in process of development, will include existing TSV's concrete pedestals evaluation for new TSV loads.

3.8.2 Water Conveyance System

The Helms Powerhouse Complex intake includes the following major water conveyance elements, mostly underground or under water:

- Intake-Discharge Structure in Courtright Reservoir;
- Tunnel 1: 27-foot inside-diameter (ID) concrete-lined 4,200-foot-long pressurized tunnel;
- Tunnel 1 gate shaft;
- Lost Canyon Crossing: 22-foot inside-diameter steel pressurized conduit;
- Tunnel 2: 27-foot inside-diameter (ID) concrete-lined 9,000-foot-long pressurized tunnel;
- Inclined Shaft: 27-foot ID concrete-lined 2,500-foot-long pressurized tunnel;
- Three Penstock Tunnels: 11.5-foot ID steel-lined 500-foot-long pressurized tunnel;
- Tunnel 3: 27-foot ID concrete-lined 4,000-foot-long pressurized tunnel; and
- Intake-Discharge Structure in Lake Wishon.

General Comments

In general, all the concrete elements are potentially subject to "normal' deterioration over time – shifting, spalling, cracking, etc. While the available information does not indicate any significant concerns in this regard, detailed assessments and mapping of observed deteriorated areas will need to be performed and generalized minor repairs (grouting, patching, etc.) will be required in localized areas that have suffered minor deterioration. Similar inspections/mapping/localized repairs will also need to be performed on the coatings of the steel water conveyance elements.

Intake-Discharge Structures in Courtright Reservoir and Lake Wishon

Once the upgrade of motor-generator and pump-turbine units is performed, the intake-discharge structures will be exposed to higher flows. It is recommended to evaluate and analyze the existing trash racks evaluation for higher flows as well as to perform existing intake-discharge structures concrete condition assessment as well as concrete scour potential evaluation because of higher flows.

Concrete Lined Tunnels 1, 2 and 3 and Inclined Shaft

It is recommended to perform the existing tunnels 1, 2 and 3 and Inclined Shaft concrete liner condition assessment as well as concrete scour potential evaluation because of higher flows.

Lost Canyon Crossing

It is recommended to perform the existing steel conduit condition assessment prior to the existing motor-generator and pump-turbine units output increase – general condition, thickness, coatings integrity.

Tunnel 1 Gate Shaft

Tunnel 1 Gate Shaft is housing fixed wheel gate. The existing gate shaft is around 228 feet high and is covered at top with gate house.

It is recommended to perform a detailed condition assessment of existing Tunnel 1 Gate Shaft prior to motor-generator and pump-turbine unit’s upgrade.

It is recommended to perform a detailed condition assessment of existing gate to determine gate remaining life. Also, it is necessary to perform gate hydraulic pull-down or transient uplift force analysis against new flows as well as gate loading ability to drop under full load in emergency gate drop situation. As a part of gate shaft condition assessment, it is recommended to perform gate gains and roller path checks.

Intake gate hoist floor should be evaluated for higher hydraulic downpull forces.

Penstock Tunnels

See general water conveyance comments above. It is recommended to perform penstock tunnels condition assessment prior to motor-generator and pump-turbine unit’s upgrade. Also, TSV replacement project, which is currently in process of development, will evaluate penstock’s mating flanges for higher flows and higher reaction forces during the emergency closure.

4.0 Conclusion

Stantec has evaluated all major equipment and systems at Helms PSP and has identified recommendations for life extension and potential upgrade of the units. In our opinion, much of the equipment is approaching the end of its service life and needs refurbishment or replacement. The condition assessment and recommendations are based on reviewing available information from previous reports, meetings with PG&E, industry standards and our experience with similar pump storage plants. We have also recommended additional evaluations/analyses on specific equipment to further refine the scope of the project.

In the interest of PG&E's objective, we have created Table 1-1 in the Executive Summary Section that provides the condition of each major equipment and our recommendation for future consideration for the project as well as a table at the beginning of each sub-section for ease of navigation.

Additionally, for all systems whose condition was evaluated, recommendations are made for adequacy for a potential 460 MW uprate as well as constraints. Although the water passage may have additional hydraulic capacity, Stantec recommends PG&E to consider a potential uprate in the range of 455MW – 460 MW maximum power output. This would limit the risks including high velocities in the water passage, major draft tube modifications, RSI concerns and cavitation issues that we have encountered in other uprate projects.

Stantec is working on reviewing several alternatives for the project that will include pros/cons for each alternative, costs and schedule impacts and benefits to PG&E.

ATTACHMENT 40

Stantec Analysis of Alternatives

CONFIDENTIAL

ATTACHMENT 40

Stantec Analysis of Alternatives

PUBLIC

Pacific Gas & Electric Company

Analysis of Alternatives Helms Uprate

Prepared for:
Pacific Gas and Electric

Prepared by:
Stantec Consulting Services, Inc.

March 2024

FINAL DRAFT

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Stantec

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Abbreviations and Acronyms

AACE	Association for the Advancement of Cost Engineering
AC	Alternating Current
B&V	Black & Veatch
BIL	Basic Insulation Level
BoP	Balance of Plant
CBA	Cost-Benefit Analysis
CFD	Computational Fluid Dynamics
cfs	Cubic feet per Second
DFIM	Doubly Fed Induction Machine
FEA	Finite Elements Analysis
FERC	Federal Energy Regulatory Commission
GE	General Electric
GmbH	Gesellschaft mit beschränkter Haftung
GSU	Generator Step-Up
GWh	Gigawatt hours
HMI	Human-Machine Interface
HV	High Voltage
HVAC	Heating, Ventilation, and Cooling
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IPS	Iron Pipe Size
MBoP	Mechanical Balance of Plant
MCC	Motor Control Center
MT	Magnetic Particle Testing
MVA	Megavolt Ampere
MW	Megawatt

NDE	Non-Destructive Examination
NETA	International Electric Testing Association
NPSH	Net Positive Suction Head
O&M	Operating and Maintenance
OEM	Original Equipment Manufacture
OMI	Operation and Maintenance Instructions
OPCC	Opinion of Probable Construction Cost
PG&E	Pacific Gas and Electric
PPT	Power Potential Transformer
PSERC	Power Systems Engineering Research Center
PSP	Pumped Storage Plant
RLZ	Rough Load Zone
RSI	Rotor Stator Interaction
TSV	Turbine Shutoff Valve
UPS	Uninterruptible Power Supply
USD	US Dollar
UT	Ultrasonic Testing
VLA	Vented Lead Acid

Executive Summary

Stantec was retained by Pacific Gas and Electric Company (PG&E) to perform an alternative analysis to provide information that can be used to help them determine the best alternative for the Helms Pumped Storage Plant (PSP) uprate project (Helms). The plant was originally commissioned in 1984 and major equipment at the plant is approaching the end of its original design life of 40 years.

The study includes data review and alternatives evaluation through energy generation review, cost estimating, and benefit and risk analyses to help determine a cost-effective strategy to maintain unit reliability, while at the same time exploring uprate options to increase the operational flexibility and value of the plant. This report summarizes the alternatives evaluation with review of the associated data. The previously completed Stantec Engineering Assessment Report dated September 2023 documents the remainder of this Phase 1 major engineering study of the uprate potential for Helms PSP. The main conclusion of the Stantec Engineering Assessment Report was that the units have an uprate potential of approximately 45 – 55 Megawatts (MW) per unit, increasing the peak power output per unit from the current nominal maximum generator output of 404 MW to approximately 450 MW – 460 MW.

Following review of this information and discussions with PG&E, six alternatives were selected for analysis and are outlined below:

<u>Alternative 1:</u> No Uprate – Status Quo (83 MW to 404 MW)

> Extend the life of Helms by another 40 years without uprating of any equipment. Components requiring replacement to achieve the additional 40 years of life will be replaced with similar equipment that may provide additional efficiency through modern technology without uprating them. New runners and wicket gates incorporating modern design features and materials would be provided, but without considering a unit uprate and with the expectation of similar operating characteristics as the existing unit. All other alternatives aim to extend the life of Helms by another 40 years as well.

<u>Alternative 2:</u> Status Quo – Wider Operating Range (<83 MW to 404 MW)

> Same scope as Alternative 1 above, but also aiming to reduce the lower operating limit below the current lower limit of 83 MW. Review of the provided 10 years of operation data (2013 – 2023) has shown that the units are operated frequently at 83 MW. It is assumed that there is a significant benefit for PG&E to operate the units at their current lower limit and, based on PG&E's request, lowering the lower operating limit further would have an additional benefit.

<u>Alternative 3:</u> Uprate to Maximum Feasible Capacity (83 MW to 450 – 460 MW)

> Uprating the units to the maximum feasible capacity while keeping the lower operating limit at the current lower limit of 83 MW. The target uprate range, as identified by PG&E, is 50 – 60 MW per unit (150 MW – 180 MW for the entire plant). Stantec has performed an independent engineering assessment/uprate study and determined that the maximum recommended uprate for the Helms pump-turbines is 450 MW – 460 MW (or approximately 45 -55 MW of additional turbine output per unit).

Alternative 4: Uprate to Max. Feasible Capacity with Wider Operating Range (<83 MW to 450 – 460 MW)

Same scope as Alternative 3 above, but also aiming to reduce the lower operating limit below the current lower limit of 83 MW. Due to the already large operating range of the existing units, increasing the maximum output while at the same time lowering the lower operating limit is deemed not feasible at this point. Hence, Alternative 4 is not reviewed in detail and is only listed for completeness throughout this report. Alternative 4 was removed from consideration early in the study.

Alternative 5: Variable Speed Unit

One unit would be converted to a variable speed unit with a doubly fed induction machine (DFIM) and a frequency converter as alternating current (AC) excitation for the rotor winding; and the two remaining units would be uprated the same as described in Alternative 3, to achieve the overall desired plant output increase of 150 – 180 MW. Frequency converters require significant additional space inside the powerhouse and required additional operating and maintenance (O&M) tasks for the plant. Based on preliminary performance estimates, the benefits of a variable speed unit is expected to be minimal at Helms. Typically, the most valued benefit of adjustable speed units for reversible units is that it provides the ability to regulate (vary) power input in pump mode. As the main goal for the Helms units is an increase of power output in generation mode, and pumping mode considerations are secondary, the primary benefit of variable speed would be reducing the part load rough operating zone in generating mode. As the cost of the DFIM, the frequency converter, and excavation to expand the powerhouse cavern in order to house the frequency converter would be substantial, the net potential benefits appear to be minimal. Therefore, Alternative 5 was removed from consideration early in the study.

Alternative 6: Addition of New Unit 4

The desired output increase of 150 – 180 MW of total plant capacity would be achieved by adding a new unit (unit 4) to the existing powerhouse. The existing three units would be treated the same as described in Alternative 1. Due to the high cost and significant construction effort to extend the powerhouse cavern and water conveyance system for a new unit, this alternative was removed from consideration early in the study. Alternative 6 is only listed for completeness throughout this report and was not reviewed in detail.

The evaluation of the alternatives documented in this report were developed based on project and unit information and data provided by PG&E, previous uprate studies completed by other parties, the Stantec Engineering Assessment Report and relevant Stantec in-house information from the industry and other similar projects. It should be noted that the alternatives analyses included analyses done subsequent to preparation of the Engineering Assessment Report; as such, this Report includes recommendations that have evolved or been modified from those in the Engineering Assessment report.

Subsequent to development and agreement that the Alternatives Analysis would include the six alternatives summarized above, PG&E identified a seventh alternative that PG&E believes may be beneficial and worthy of consideration. This alternative is outside the scope of this Alternatives Analysis report, but a description is attached as an Appendix to this report for potential future consideration. This alternative consists of the addition of New variable speed Units 4 and 5 along with addition of synchronous condenser capability for the existing units 1, 2, and 3.

A preliminary Opinion of Probable Construction Cost (OPCC) was developed for each alternative. The OPCCs are considered Class 5 as defined by AACE (Association for the Advancement of Cost Engineering) International in Recommended Practice 69R-12. The preliminary OPCC is provided in 2023 USD (US Dollar) and includes a 10 percent markup for owner's internal costs (15% for alternative 6). Table 1 below summarizes the estimated costs for each alternative.

Table 1. Class 5 Cost Estimate (low, mid, high) by Alternatives

		Total Cost Estimate (2023 million USD w/ allowance)
Alternative 1	low	142.4
	mid	**203.5**
	high	305.2
Alternative 2	low	142.4
	mid	**203.5**
	high	305.2
Alternative 3	low	218.3
	mid	**311.8**
	high	467.7
Alternative 4	low	218.3
	mid	**311.8**
	high	467.7
Alternative 5	low	267.5
	mid	**382.2**
	high	573.3
Alternative 6	low	329.9
	mid	**471.3**
	high	707.0

Each alternative was ultimately scored based on its merits, demerits, and cost in the following categories. Each category was assigned a weighting factor, and a total weighted evaluation score was calculated. The individual scores and weighting factors selected and used in this Report were based on Stantec experience and professional judgment; PG&E could use the information in the report to perform sensitivity analyses of the results by varying individual weighting factors, thereby assessing the sensitivity of the alternative selection to specific evaluation categories.

- Construction Cost (15% weighting factor)
- O&M Cost Consideration (5% weighting factor)
- Outage Duration (10% weighting factor)
- Expected Reliability (15% weighting factor)
- Risk (10% weighting factor)
- Best Technical Solution (25% weighting factor)
- Amount of Integration Work (5% weighting factor)
- Expected Benefit (15% weighting factor)
- **Total Score** **0.15xCC + 0.05xO&M + 0.10xOD + 0.15xER + 0.1xR + 0.25xBTS + 0.05xAIW + 0.15xEB**

An actual Cost-Benefit Analysis (CBA) was not performed for this report because benefits values, consisting of proprietary internal PG&E pricing information on capacity, energy, and ancillary services, is proprietary and confidential and could not be shared for this analysis. It was agreed that PG&E will use the costs provided from this report and complete their own CBA to determine financial viability and pay back periods for each alternative. Hence, the expected benefits established in the report are based largely on cost, risk, and technical considerations, plus a qualitative assessment of technical benefits.

Individual scores were assigned from 1 to 6, with 6 being the highest achievable score and the most desirable alternative and 1 being the lowest score and the least desirable alternative. Table 2 below summarizes the final scoring of each alternative.

Table 2. Final Score by Alternative

Category	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5	Alt. 6
Construction Cost	6	6	4	4	2	1
O&M Cost Consideration	4	4	6	6	2	1
Outage Duration	6	5	4	3	2	1
Expected Reliability	2	1	6	5	4	3
Risks	6	5	3	2	1	4
Best Technical Solution	3	1	4	2	5	6
Amount of Integration Work	6	5	4	3	2	1
Expected Benefit	1	2	3	4	5	6
Final Ranking	**3.80**	**3.05**	**4.15**	**3.40**	**3.40**	**3.60**

Rank 1: Alternative 3 - Uprate to Maximum Feasible Capacity (83 MW to 450 – 460 MW)

Alternative 3 is the recommended uprate option for Helms PSP. It is the highest scoring alternative, has the highest expected reliability out of all options and the lowest expected O&M cost over a 40-year lifespan. It scores third highest in the category of Best Technical Solution, behind the more expensive alternatives 5 & 6. This alternative ranks the highest due to its relatively high scores across all categories. Most other alternatives are strong in certain categories, while weak in other categories. Alternative 3 scores high as the best “all-round” solution. It has relatively high scores in the most weighted categories such as Best Technical Solution, Expected Reliability, and Construction Cost. It is also the only viable uprate alternative that does not require major structural modifications to the powerhouse. The only other uprate alternative not requiring such structural modifications would be alternative 4, but that alternative is deemed not feasible due to the large operating range it would require. Alternative 4 also has a much lower score than alternative 3 and was ruled out from further investigation early during this study. .

Rank 2: Alternative 1 - No Uprate – Status Quo (83 MW to 404 MW)

Alternative 1 ranks in second place, only marginally ahead of alternative 6, due to its proven track record of operation to date, plus the overall simplicity of its scope of work. This alternative would aim to replace components that are at end-of-life without uprating them. No significant engineering and new design work is required and the risks for this alternative are low. It also has the cheapest expected cost and lowest outage duration of all alternatives. There is minimal to no integration work required for this alternative. However, it ranks last in the expected benefit category and is only fourth in the best technical solution category. Overall, this alternative is a good alternative for life extension of the Helms PSP if the focus is a conservative life extension capital investment with the most “knowns" and fewest “unknowns”.

Rank 3: Alternative 6 - Addition of New Unit 4

Alternative 6, although ranking in 3rd place, was excluded from consideration early in this study, because it was recognized qualitatively, early in the evaluation process, that its higher relative costs would outweigh its relative benefits; the scoring in Table 2 above confirms this decision. Alternative 6 is the lowest ranking alternative in 4 out of the 8 categories reviewed. Construction cost, outage duration, and future O&M cost are estimated to be the highest out of all alternatives. Therefore, it is not recommended to pursue this alternative any further. It is listed throughout this report for completeness only,

Rank 4 (Tied): Alternative 4 - Uprate to Maximum Feasible Capacity with Wider Operating Range (<83 MW to 450 – 460 MW)

Alternative 4 is an alternative that is deemed not technically feasible. The existing Helms units have an wide generation operating range (from 83 – 404 MW) that is already wider than many other pumped storage units. Stretching this operating range further (lower) has its limitations – reduced maximum output would be the likely result of lowering the minimum output. However, Alternative 4 aims to increase the peak power output to 450 – 460 MW while ***also*** lowering the lower operating limit. As noted, both of these requirements cannot be achieved at the same time. Since PG&E put their main objective as increasing the maximum output capacity and not a lower minimum capacity, alternative 4 ranks behind alternative 3 in all categories but one. Only the expected benefit would be higher for alternative 4 when compared to alternative 3. Therefore, it is not recommended to pursue this alternative any further.

<u>Rank 4 (Tied):</u> Alternative 5 - Variable Speed Unit

Alternative 5 was removed from consideration early in this study, because it was also recognized qualitatively, early in the evaluation process, that its higher relative costs and risks would outweigh its relative benefits. Again, the final weighted scoring confirmed this decision. Only alternative 2 ranks overall lower. The significant costs and outage duration associated with this alternative as well as the overall highest risk and significant amount of integration work, make this an alternative that is not t recommended to pursue further.

<u>Rank 6:</u> Alternative 2 - Status Quo – Wider Operating Range (<83 MW to 404 MW)

This alternative ranked last because it had the lowest score of all alternatives in two key categories of this study: Expected Reliability and Best Technical Solution. It also ranked low in the Expected Benefit category due to this alternative not offering the desired uprate. Advantages of this alternative such as cost, outage duration, low risk, and low amount of required integration work – for which this alternative received high scores in each category – were not enough to outweigh the low scores in high weighted categories. Hence, it is not recommended to pursue this option further.

In conclusion, out of the six alternatives evaluated as part of this alternatives analysis, two alternatives are recommended for further consideration by PG&E. Based on PG&Es objectives and goals for the project, , n Stantec's review of all alternatives, and the overall results of the analyses as summarized in the weighted evaluation scores, Alternative 3, and then Alternative 1, are evaluated as highest and recommended as the preferred alternatives over the other investigated alternatives.

Since the highest priority goal of the overall Helms Uprate Project is to look for additional generation capacity, alternative 3 (max. uprate) is clearly the preferred solution. It achieved the highest overall score and offers the desired increase in plant capacity of approximately 150 MW. While alternative 1 has its merits, especially its low risk, cost, and integration work, it virtually offers no benefit to PG&E other than life extension. Alternative 3, on the other hand, takes advantage of the available infrastructure and offers the desired uprate capacity. Most existing equipment is at the end of its original design life and a lifetime extension project for Helms is imminent. Since this lifetime extension project will require refurbishment and replacement of major components of the plant, as described in the scope of work for alternative 1, simultaneously uprating these components for alternative 3 to increase generating makes sense. The incremental cost increase for the uprate component is expected to be outweighed by the expected benefits coming from the increased unit capacity.

1.0 Background

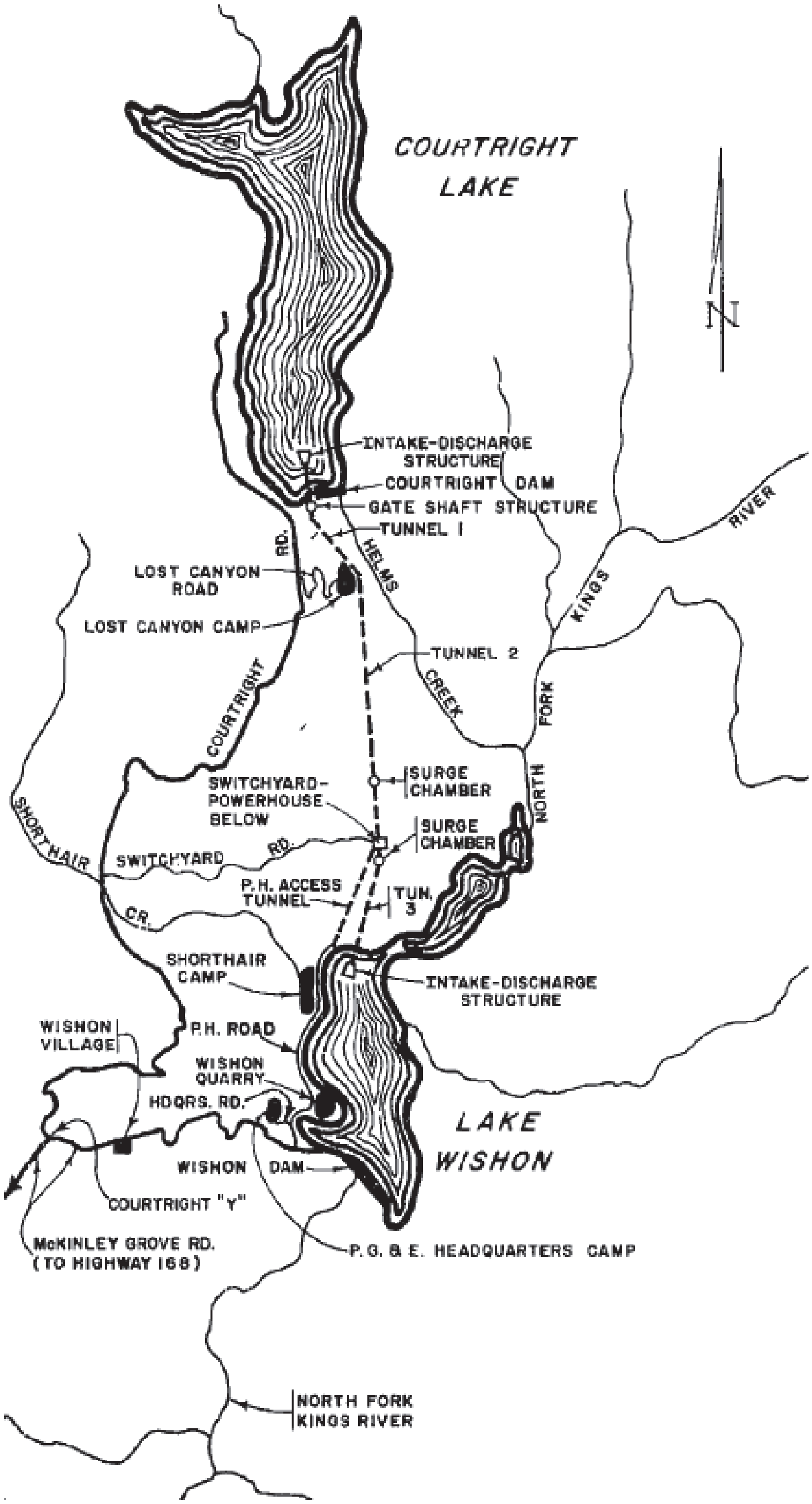
The Helms PSP is located in the mountains east of Fresno, California, is owned and operated by PG&E, and was commissioned in 1984. The plant operates between the upper reservoir (Courtright Reservoir) and the lower reservoir (Wishon Reservoir). The plant has three pump-turbine / motor-generator units with a nominal maximum generator output of 404 MW each, for a total installed nominal generator capacity of 1,212 MW.

PG&E is seeking to uprate the plant with its current three units by a target of approximately 150 MW - 180 MW (of total generation) by upgrading turbine, generator, transformers, and other auxiliary components to maximize the power output based on the existing water infrastructure. Original Equipment Manufacturer (OEM) and consultant engineering studies have been performed to identify the main scope necessary to achieve the uprate. Based on this preliminary analysis, PG&E plans to, at a minimum, upgrade and refurbish the turbine, rewind the generators, replace the stator cores, improve the rotors, replace the main bank transformers, replace the reverse disconnect switches with motor-generator circuit breaker, and upgrade the iso phase and exciter bus.

A profile section of the project is shown in Figure 1. A map of the Helms PSP project area is shown in Figure 2. Water is taken from the upper reservoir, Courtright Lake, through an intake-discharge structure north of Courtright Dam. Water is conveyed through Tunnel 1, passing the Lost Canyon Crossing, into Tunnel 2. Before entering the powerhouse, at station 139+47.0 Tunnel 2 drops at a 56 degree incline before three individual penstocks enter the powerhouse. On the downstream side of the powerhouse, three individual draft tube sections merge into a combined Tunnel 3 that discharges into Lake Wishon at the Wishon intake-discharge structure.

[redacted]

Figure 1. Helms PSP Profile View



Ref. PG&E Drawing No. 432922

Figure 2. Helms Project Map of Construction Area

1.1 Objective

The Helms units are nearing the end of their original design life (expected 40 years) and will require rehabilitation or replacement in the coming years. Additionally, PG&E has determined a benefit of increasing the overall plant generator capacity by a target range of 150 MW – 180 MW total. As such, PG&E has requested that Stantec develop upgrade options and evaluate corresponding costs. Benefits will be determined by PG&E following the completion of this alternatives study. The primary objective of this study is to aid PG&E in the selection of the preferred alternative and its key parameters (namely, megawatt capacity and range) for the rehabilitated or upgraded units.

The upgrade options are intended to have a minimum life expectancy of 40 years.

The alternatives analysis, presented herein, aims to provide information that can be used by PG&E in their final selection of the preferred alternative and its key parameters (namely, approximate megawatt capacity and range). Additional alternatives, when compared to the previous study completed by B&V, were added to further expand and broaden the scope of the uprate project. These alternatives are described in detail in section 4.0 of this report.

1.2 Previous Studies

Previous studies on the uprate potential of Helms PSP have been performed by various OEMs as well as previous engineering firms supporting this project. While the OEM studies focused on individual equipment of the plant, namely the motor-generators and pump-turbines, Black & Veatch (B&V) issued an overall upgrade study for the entire plant in August 2021.

The following OEM studies were provided to Stantec and have been considered in Stantec's Engineering Assessment Report (Stantec 2023) as well as in this present study:

1. **Hitachi Documents:**
    - 1.1 Phase-I Report_WP-3290_R0
    - 1.2 Phase-II Report WP-3351_R0 with Attachments
    - 1.3 Phase-III Report_WP-3444_R0
    - 1.4 HEL-PT-006_R0_Summary of Turbine Uprate Study_Oct 17
    - 1.5 WP-3650_R0_final_Deliverable of Phase-IV Pump Study
    - 1.6 EESP-03152_R0_HelmsAdjustableSpeedReply_20221207
    - 1.7 RE Helms case Adjustable Speed Hydro Unit Technology Inquiry (Email)
2. **GE (General Electric) Documents:**

    Helms Uprate Study - GE-Final

3. **Voith Documents:**

   3.1 Helms PSP_UprateStudy-ElectricalDesign_2021-12-15_(RevB_2022-10-18)

   3.2 HELM-2GEN60-1100-10276982-Rev--TR_BEARING_THRUST__LOAD_CAPACITY_REVIEW

   3.3 HELM-GEN60-1100-10255871-TR_Thrust_Bearing_Load_Capacity_Presentation_Rev-

   3.4 HELM-GEN60-1100-10276986-TR_Stator Frame_and_Foundation_Presentation_Rev-

   3.5 HELM-GEN60-1100-10276988-TR_Generator_Brake_Assessment_Presentation_Rev-

   3.6 HELM-GEN60-1100-10276989-TR_Shaft_Line_Analysis_Presentation_Rev-

   3.7 HELM-GEN60-1100-10276989-TR_Shaft_Line_Analysis_Presentation_Rev-Improvements

   3.8 HELM-GEN60-1100-10276990-TR_Shaft_and_Shaft_Coupling_Stresses_Rev-

   3.9 HELM-2GEN60-1100-10276992-Rev--TR_GENERATOR_UPRATE_STUDY_EXECUTIVE_SUMMARY

The following B&V studies were provided to Stantec and have been considered in Stantec's Engineering Assessment report (Stantec 2023) as well as in this present study:

4. **B&V Documents:**

   4.1 Helms Uprate Study B&V - Final

   4.2 Helms Uprate Transient Study – Final

The B&V uprate study focused on the following areas:

- Need for additional pump storage capacity in California
- Hydraulic capacity of Helms
- Alternatives for adding additional generation capacity to Helms
- Cost estimates

The main alternatives considered during B&Vs analysis were:

- Uprate of existing units to 460 MW each
- Install a new Unit 4
- Uprate the existing units and install a new unit 4

The B&V study concluded that adding additional generation at Helms is a viable option. The existing water conveyance systems provide sufficient hydraulic capacity to produce additional pump storage generation. This would result in one of the most cost-effective pump storage projects currently in development. Expanding the existing facility, instead of developing a new greenfield facility, would also reduce permitting risks and complexity according to B&V. It was recommended to perform a detailed uprate study to determine the scope of work involved with the uprate project.

5. Stantec Documents:

- Engineering Assessment Report

Stantec performed a detailed engineering assessment to summarize the condition of the existing equipment and its uprate potential. Refer to Stantec's Engineering Assessment Report (Stantec 2023) for technical details on existing equipment description. The Assessment report summarized the scope of work for the uprate of the existing units at that point in time. Further assessments and analyses were carried out as part of the assessment of alternatives, and so the elements and details of the scope of work described in this Analysis of Alternatives Report incorporates an evolution (i.e., modification) of that described in the Assessment Report.

2.0 Analysis Criteria and Assumptions

This section provides an overview of the analysis criteria, assumptions, and PG&E's requirements for the evaluation of the investigated alternatives. Additionally, historical operational data from 2013-2023 (which PG&E advised is representative of the future project operations) was reviewed and assessed by Stantec as information to be considered when evaluating the alternative; that historical operational data is summarized in this section.

After reviewing available data, Stantec completed a preliminary assessment and uprate analysis and documented the findings in a separate Engineering Assessment Report (Stantec 2023). The intent of the preliminary uprate analysis was to provide an estimate of the maximum feasible unit (and plant) capacity at Helms. The uprate assessment considered the existing equipment's condition, outlined what equipment will require replacement (versus refurbishment), and addressed the incremental changes required to achieve the uprate capacity.

Based on the review conducted for that Assessment study, the limiting factor for the uprate is the pump-turbines. All other equipment either has sufficient capacity, or could be replaced with equipment of sufficient capacity, to meet the maximum uprate limit of the pump-turbines. Also, increasing the hydraulic capacity through the existing water conveyance system to meet the maximum established uprate target of 460 MW per unit (generator output) was deemed feasible.

Note that Stantec did not complete an independent condition assessment as part of the assessment study. Rather, as discussed and agreed with PG&E and defined in Stantec's scope for the Assessment report, Stantec performed a desktop assessment that relied on the condition as characterized by previous studies, supplemented by verbal discussions with PG&E.

2.1 Owner's Requirements and Constraints

While conventional hydroelectric powerplants may typically be designed for a life of 50 years, pumped storage plants are typically designed for a 40-year design life. This is in large because mechanical and electrical components of a PSP are designed for a more severe duty cycle – pump and generate operations, plus more frequent starts/stops than in a typical conventional generation-only hydroelectric plant. The structural components of a PSP are typically designed for the same 100 years of design life as conventional plants. Since Helms PSP was commissioned in the 1980's, most of the mechanical and electrical equipment is expected to currently be at or near the end of its remaining original design service life. Helms PSP would need to undergo a lifecycle extension process over the coming years to achieve the 40-year life extension goal, without considering any uprate. Since this would involve major capital projects for equipment refurbishment and replacement, uprate of equipment for an incremental increase in cost above the life extension cost, to generate additional energy and improve operating flexibility would potentially be beneficial.

2.2 Historical and Future Operation

Based on PG&E O&M personnel feedback provided during an operations review meeting held on July 12, 2023, all three units are being operated as uniformly as possible to ensure uniform wear across all three units. The current operation of the plant can vary on a daily basis, but on average 1-2 pump starts per unit per day and 2-3 generation starts per unit per day have been observed for a number of years. This is in line with a self-imposed limitation that PG&E put on the Helms units of a maximum of two pump starts per day and three generation starts, for a total of five cycles per day. Based on demand, dispatch would cycle the Helms units significantly more if this self-imposed limit was not in place. PG&E has also put a self-imposed 1-hour minimum run time on each unit, so that heat cycling of the units as well as power tunnel dynamics are better controlled. Once a unit is shut down again, there is a self-imposed 1-hour cooldown period as well. Operation of the units can vary seasonally. During the summer, the units are pumping for the better part of the day. During periods of low reservoir elevations, the units tend to cycle more, due to the overall lower water volume in each reservoir. PG&E operations monitor breaker counts on each unit and change dispatch orders on occasion to keep uniform wear on all units. During emergency dispatch conditions - mostly during the summer months - the imposed operating restrictions outlined above are overruled and units can be cycled more and can be operated without the 1-hour time limits after start-up and shut-down, respectively.

PG&E provided Stantec with hourly operating data for the period June 21, 2013, through May 29, 2023, a 10-year period. The data provided includes Courtright Reservoir Water Elevation, Wishon Reservoir Water Elevation, Gross Head, Unit 1-3 MW, and Unit 1-3 Flow. This data is summarized in the duration and exceedance curves below. Note that this dataset reflects and covers the past 10 years of operation; PG&E advised Stantec that future operation is expected to be similar to the past 10 years' operation.

Annual and Monthly Generation & Pumping – The provided dataset was reviewed and evaluated for average monthly and annual energy production and use. Table 3 and Figure 3 below show the average energy production and use in Gigawatt hours (GWh) by month. Overall, distribution by month and unit is relatively even although there is an observable tendency for Unit 1 being favored in generation mode and Unit 3 being favored in pumping mode. Total GWh in pumping mode exceed the total GWh in generation mode, typical for any pumped storage plant:

Table 3. Average Monthly Energy Production by Unit

	Unit 1	Unit 2	Unit 3	Plant
Average Monthly Generation in GWh:	24	18	21	64
Average Monthly Pumping in GWh:	(24)	(29)	(39)	(92)

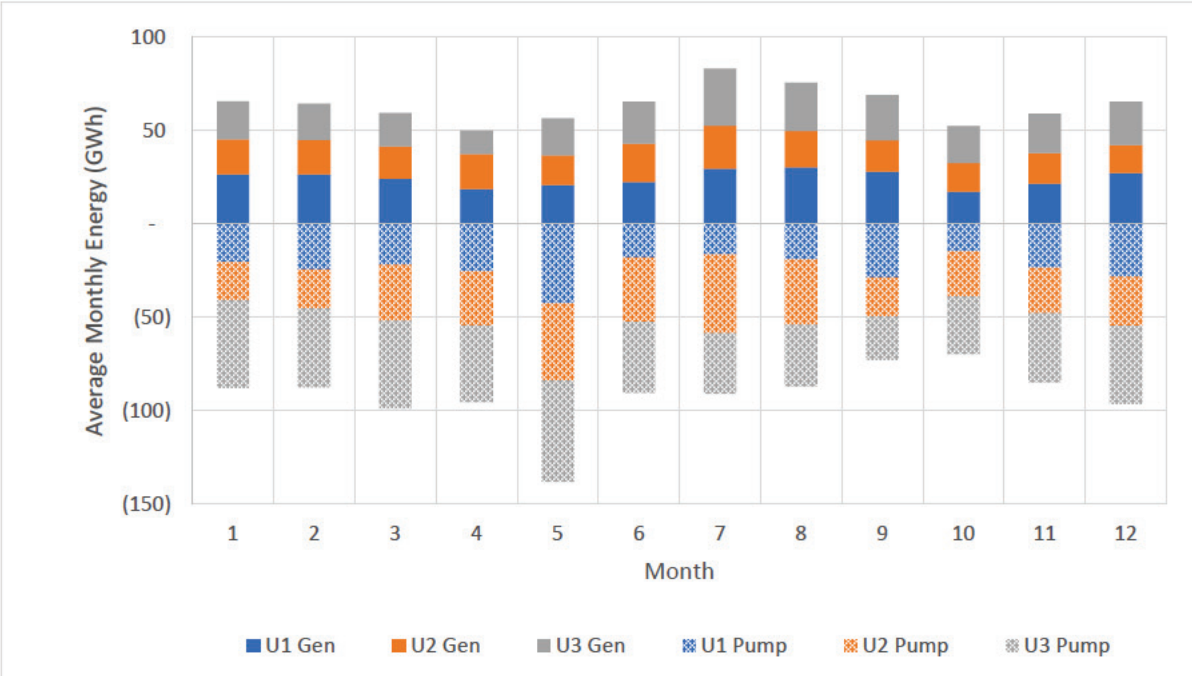


Figure 3. Average Monthly Energy Production by Unit

Average annual energy production in GWh is shown in Table 4 and Figure 4 below. The trends observed in the monthly chart above are further confirmed. Unit 1, on average, has the most energy production in generation mode and Unit 3 is favorably operated in pumping mode. Total GWh in pumping mode exceed the total GWh in generation mode:

Table 4. Average Annual Energy Production by Unit

	Unit 1	Unit 2	Unit 3	Plant
Average Annual Generation in GWh:	266	197	234	697
Average Annual Pumping in GWh:	(257)	(317)	(425)	(999)

The years 2016 and 2021 saw a moderate peak in pumping mode and a small peak in generation mode. The year 2014 was an overall low year when compared to the average energy production over the past ten years.

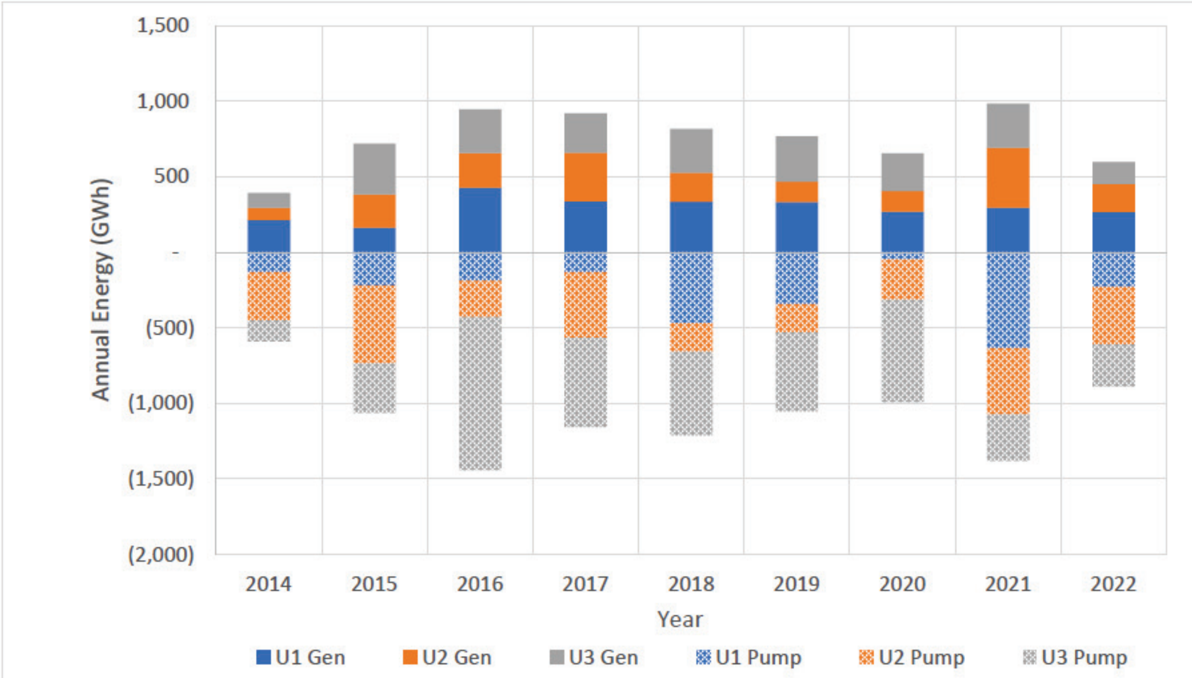


Figure 4. Average Annual Energy Production by Unit

Figure 5 below shows the distribution of time each unit operates at a certain MW output. The units generate for approximately 20% of the time, stand still for approximately 60% of the time, and pump for the remaining approximately 20% of time. The tendencies observed in the monthly and annual energy production shown in Figure 4 above can be observed here as well. Unit 1 operates most often in generation mode, while Unit 3 operates most often in pumping mode. Generation peaks at approximately 404 MW, the current nominal maximum output of the Helms motor-generators, for short periods of time. Further down, a correlation between available gross head, unit flows, and MW output will be shown to discuss this observation further. Generation above 400 MW makes up less than 1% of the overall generation time of each unit. Whereas generation at the lower limit of 83 MW makes up almost 35% of the overall generation time. The large percentage of time at minimum output illustrates the basis of PG&E's desire to reduce minimum generating output, because that would increase overall operating flexibility.

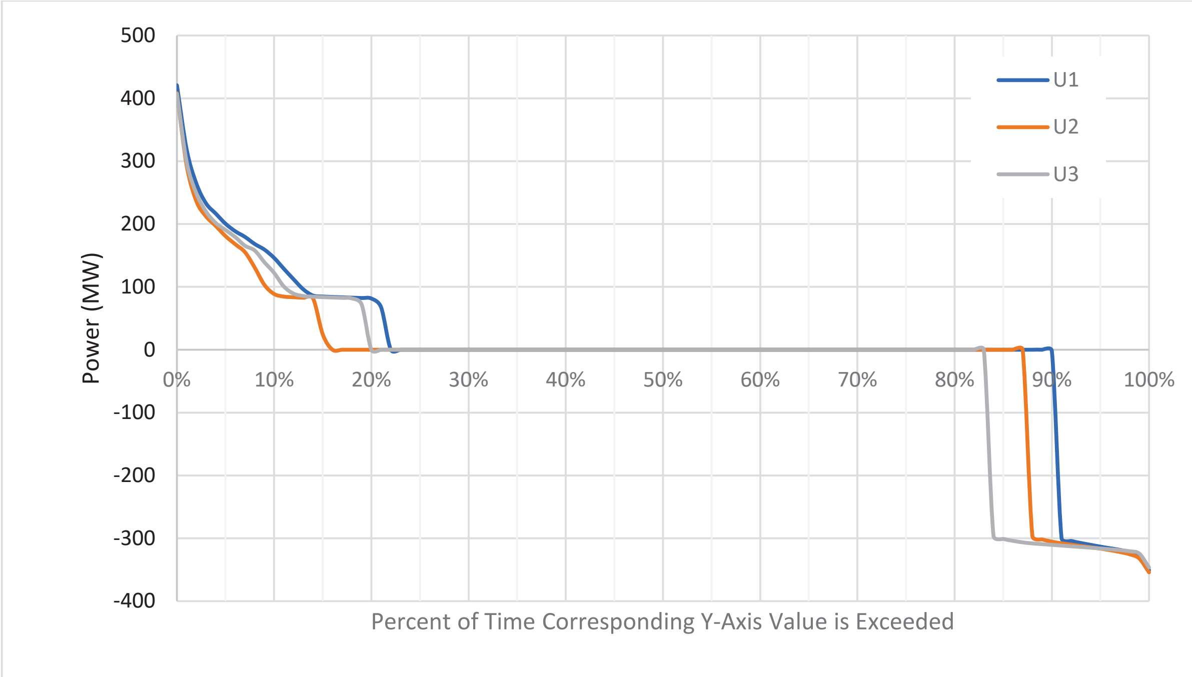


Figure 5. Power Output Exceedance Curve

Reservoir Elevations and Flows –Elevations, heads, and flows corresponding to the power output curve above can be found in Figure 6 through Figure 8 below. To achieve the nominal maximum generator output of 404 MW for all three units simultaneously, maximum gross head of 1,744 feet and maximum flow of approximately 3,300 cubic feet per seconds (cfs) are required. Since the maximum gross head is only available for short periods of time, motor-generator output of 404 MW for all three units at the same time is limited to events when maximum gross head is available. Positive flows in Figure 8 are flows in generation mode, negative flows represent pumping flows.

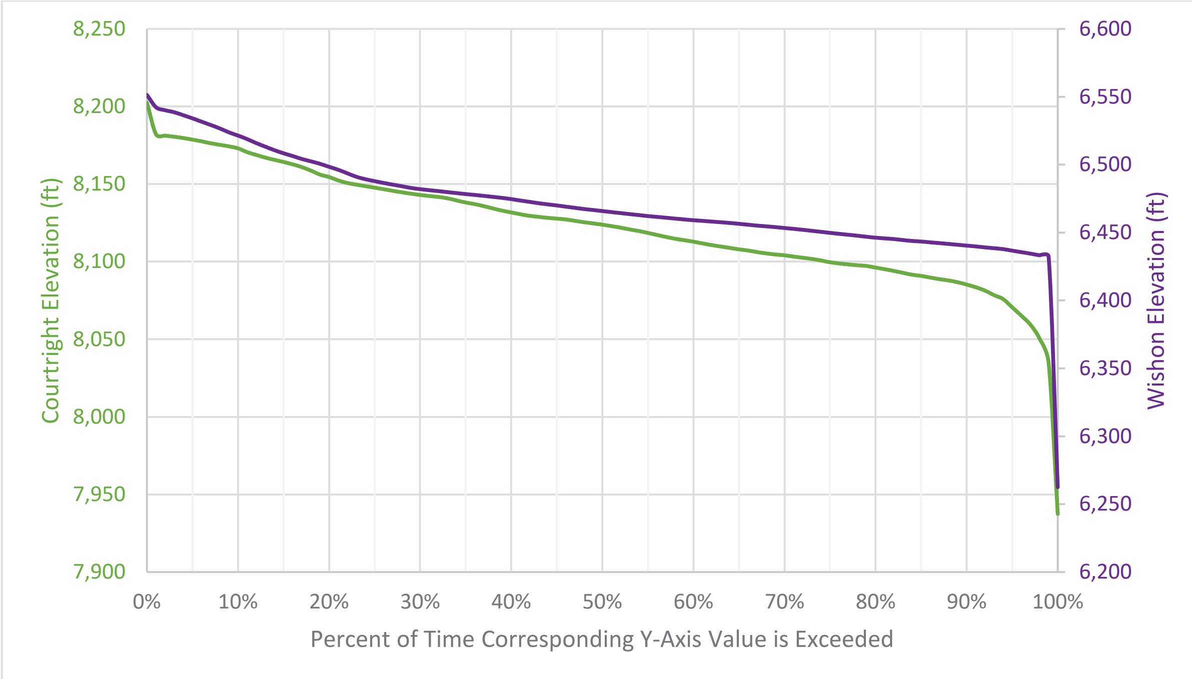


Figure 6. Wishon Reservoir Elevation Exceedance Curve

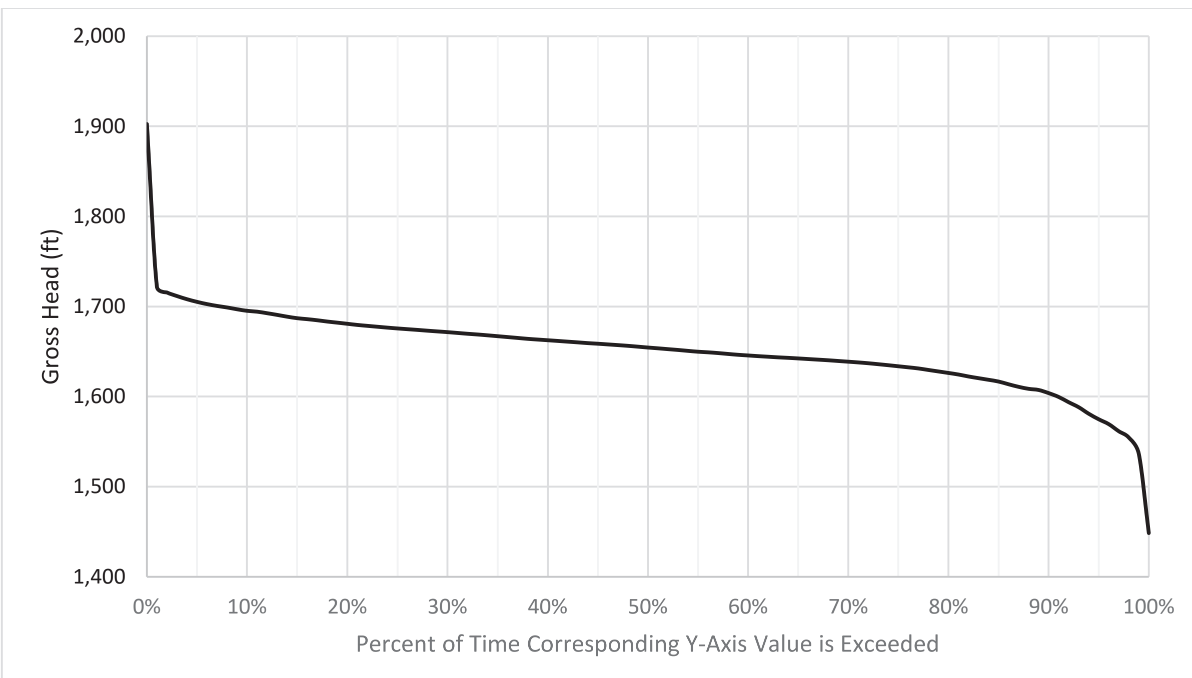


Figure 7. Gross Head Exceedance Curve

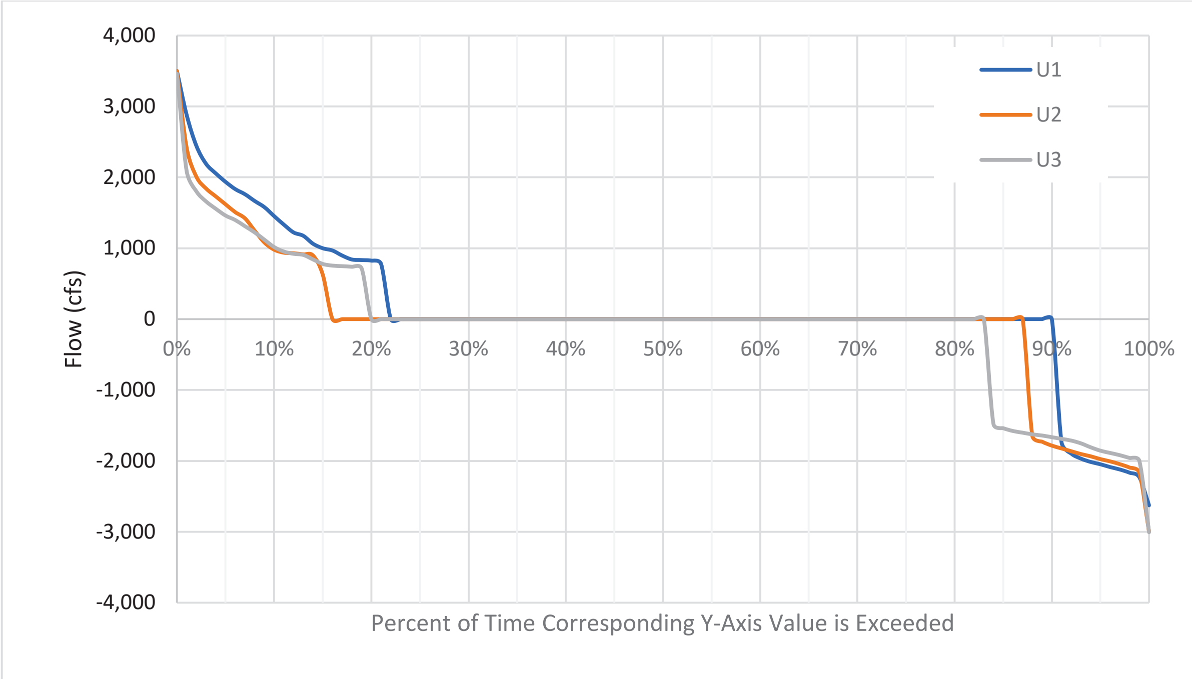


Figure 8. Flow Exceedance Curves

Generation Mode – Figure 9 and Figure 10 below show historical generation power exceedance curves and flow exceedance curves for the provided operating period from 2013 through 2023. As previously noted, PG&E advised that future operations are predicted to be similar to the last 10 years' operation. The curves show that generation is distributed evenly among the three units. The units are operated frequently at their lower operating limit of 83 MW. Almost 35% of the total generation time is spent at this lower limit. Generation between 100 MW and 250 MW makes up approximately 50% of the time. Generation at the current peak output of 404 MW makes up less than 1% of the overall generation time, and generation above 250 MW about 10% of the time.

Unit flows at the lower operating limit range between approximately 750 cfs and 1,000 cfs and occur up to 35% of the time. Fifty percent of the time, unit flows are in the range of 1,000 – 2,500 cfs. Higher flows in the range of 2,500 – 3,500 cfs are sustained less than 8% of the time. Flows to generate peak output of 404 MW appear to be in the range of 3,300 – 3,500 cfs and only occur less than 1% of the total generation time.

Conclusions of Generating Operations Analysis - Based purely on the historical operation data analyzed above, and PG&E's assertion that future operations will be similar, , the overall benefits would likely be greater by focusing more on obtaining continuous operating capability lower than the 83 MW limit, and focusing less on increasing the maximum output limit. That approach could lead to optimizing the pump-turbines for a lower generating peak efficiency point and sacrificing some maximum output capacity. However, if short-term maximum generating capability has a high power marketing and economic value (as is the case in many deregulated power markets), then the current focus on maximizing generating capacity could yield the highest total net benefits.

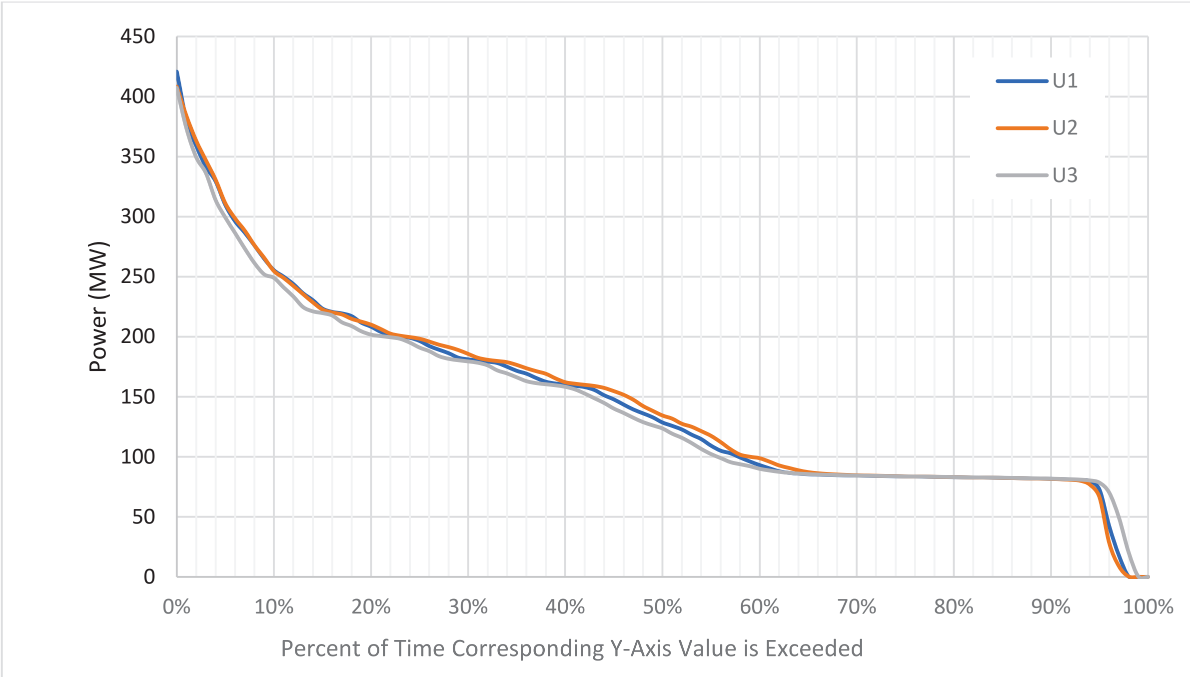


Figure 9. Generation Power Exceedance Curves - Units 1-3

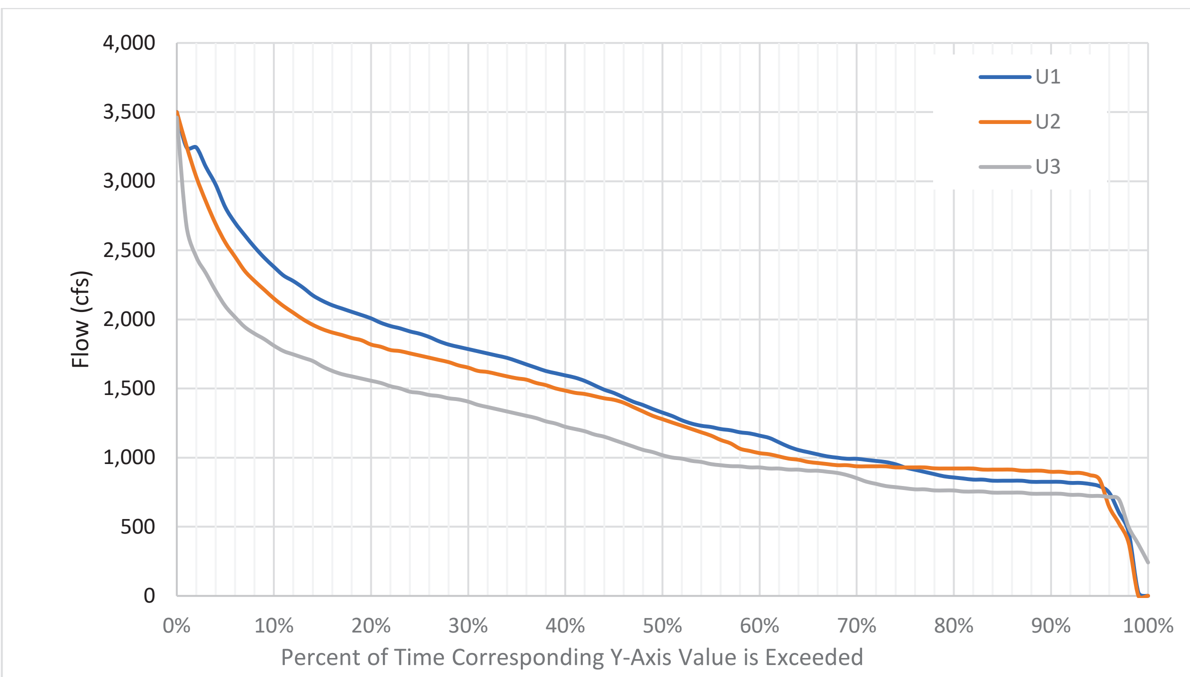


Figure 10. Flow in Generation Mode Exceedance Curves - Units 1-3

Pumping Mode – Figure 11 and Figure 12 below show historical pumping power exceedance curves and flow exceedance curves for the provided operating period from 2013 through 2023. Pumping power is approximately 290-310 MW with pump flow ranging between approximately 1,500 cfs and 2,000 cfs. As a fixed speed unit, a pump-turbine is limited to a single operating point at a given head, so pump power and flow cannot be regulated and vary depending on head conditions. When operating in pump mode, model test results suggest the existing unit has a rated flow and pump input power of approximately 2,130 cfs and 310 MW, respectively, when operating under a rated total head of 1,600 feet – but the developed pump curve suggests input powers anywhere between 275 MW (at maximum pump head of 1,764 feet) and 340 MW (at minimum pump head of 1,470 feet) would be achievable. Based on existing data, it appears actual pump input power was less than predicted by model testing. This is also reflected in the 1989 efficiency testing which suggested pump input power was about 10 MW less than that predicted from the Hitachi model test for the tested condition. This could be explained within the inaccuracies of a 50-year-old model test and within the manufacturing accuracy of a prototype runner that might not have been built in exact homology to the model or even within the application of achievable manufacturing tolerances.

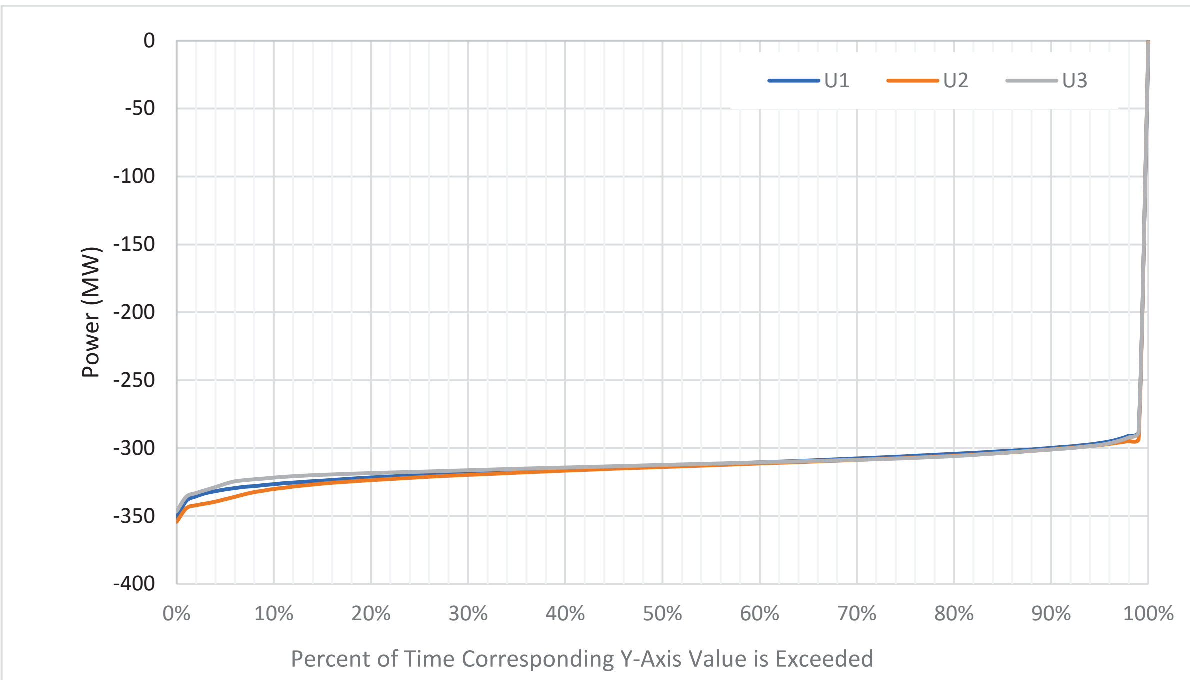


Figure 11. Pumping Power Exceedance Curves - Units 1-3

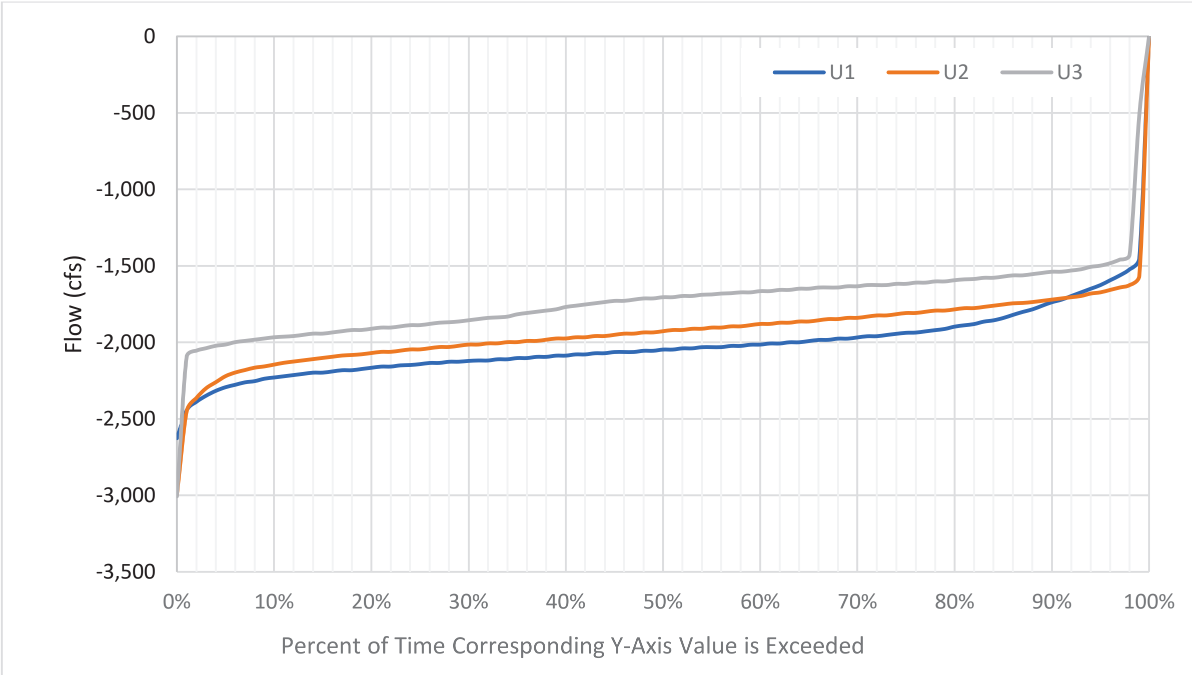


Figure 12. Flow in Pumping Mode Exceedance Curves - Units 1-3

Conclusions of Pumping Operations Analysis - Per input provided by PG&E, future operation of the plant is expected to be similar to the current operation of the plant. Consequently, pumping operations with the life extension and uprate should generally look like that provided above, with two potential caveats:

1. Modern state of the art pump-turbines can achieve better efficiencies than the original Helms units; all else being equal, this would be reflected in slightly higher pumping flows and/or lower pump input powers.

2. To the extent the new design is optimized more for maximum generating capacity than the existing design, some pumping efficiency may be sacrificed.

Other conclusions – based on current and projected markets, there may be a tendency of the units to cycle more frequently than in the past, which increased operational wear and tear, which could reduce reliability and service life. However, PG&E has indicated that reliability of the new units will be a main priority. Consequently, careful consideration should be given to the design of the new units regarding increased cycling capabilities and shorter runtimes. At a absolute minimum, the new units should be required to achieve the same reliability and availability as the existing units, even with a more severe duty cycle.

3.0 Review of Alternatives

With equipment condition and system constraints in mind, six alternative rehabilitation and upgrade scenarios were developed in coordination with PG&E; these alternatives are listed in Table 5 (note that generator megawatt output values reflect an assumed 98 percent for the generator efficiency). Further discussion of each alternative is included in Sections 4.1 through 4.6.

Following assumptions are considered in Table 5:

- Generator efficiency is 98%.
- Maximum gross head is 1,744’.
- Single unit operation at maximum gross head and maximum output results in a maximum net head of 1,719’ or 1,724’ depending on the Alternative and is presented as the maximum head operating point in the table below (head loss coefficients developed in engineering assessment study, Stantec 2023).
- Three-unit operation at maximum gross head and maximum output reduces maximum net head to between 1,690’ and 1,700’ depending on the Alternative (head loss coefficients developed in engineering assessment study, Stantec 2023).
- The numerical values presented in Table 5 were developed from Hitachi pump-turbine model test data scaled to the prototype units, plus values provided in Hitachi studies and correspondence. This provides internal consistency within this Report to all the numerical data presented in this Table and elsewhere in this Report. It should be noted that other sources (with different assumptions or bases) may show values that do not correlate or correspond exactly with the values in Table 5.

With each alternative, a primary objective is maintaining reliable operation of all units for another 40 years. As such, even options that consider addition of a new unit to increase overall plant output (e.g., Alternative 6), also include the rehabilitation of the existing units to achieve another 40 years of reliable operation. Hence, the evaluation focused on identifying a preferred alternative for rehabilitating the units. Except for Alternative 5, Units 1, 2 and 3 are assumed to be identical.

Table 5. Description of Studied Alternatives

Alternative	Description
Alternative 1 (Status Quo)	Extend the life of Helms by another 40 years without uprating of any equipment. Components requiring replacement to achieve the additional 40 years of life will be replaced without uprating them. • Single Unit Operation: – Maximum Turbine output at minimum head (1,430 feet net; 3,143 cfs): **336 MW** (329 MW generator output) – Maximum Turbine Output at rated head (1,625 feet net, 3,072 cfs): **379 MW** (371 MW generator output) – Maximum Turbine output at max. head (1,724 feet net; 3,118 cfs): **409 MW** (401 MW generator output) – Minimum Turbine Output at rated head (1,625 feet net, ~900 cfs): **83 MW** (81 MW generator output) – Generator Rated Output: **448 Megavolt Ampere (MVA)** with PF 0.90 (403.2 MW) • Three Unit Operation: – Maximum Plant Turbine output at minimum head (1,430 feet net; 9,429 cfs): **1,008 MW** (987 MW generator output) – Maximum Plant Turbine output at rated head (1,625; 9,216 cfs): **1,137 MW** (1,114 MW generator output) – Maximum Plant Turbine output at max head (1,700 feet net; 9,354 cfs): **1,203 MW** (1,179 MW generator output) – Minimum Plant Turbine output at rated head (1,625 feet net, ~2,700 cfs): **249 MW** (244 MW generator output) – Generator Plant Rated Output: **1,344 MVA** with PF 0.90 (1,209.6 MW)

Alternative	Description
Alternative 2 (Status Quo w/ Wider Operating Range)	Same scope as Alternative 1 above, but also aiming to reduce the lower operating limit below the current lower limit of 83MW. The current lower limit is already impressive with respect to other pump-turbine installations and might not be lowered following supplier design and model test, but this alternative assumes some reasonable improvement is made. • Single Unit Operation: – Maximum Turbine output at min. head (1,430 feet, 3,143 cfs): **336 MW** (329 MW generator output) – Maximum Turbine output at rated head (1,625 feet net; 3,072 cfs): **379 MW** (371 MW generator output) – Maximum Turbine output at max. head (1,724 feet net; 3,118 cfs): **409 MW** (401 MW generator output) – Minimum Turbine Output at rated head (1,625 feet net, ~875 cfs): **73 MW** (71.5 MW generator output) – Generator Rated Output: **448 MVA** with PF 0.90 (403.2 MW) • Three Unit Operation: – Maximum Plant Turbine output at minimum head (1,430 feet net; 9,429 cfs): **1,008 MW** (987 MW generator output) – Maximum Plant Turbine output at rated head (1,625; 9,216 cfs): **1,137 MW** (1,114 MW generator output) – Maximum Plant Turbine output at max head (1,700 feet net; 9,354 cfs): **1,210 MW** (1,186 MW generator output) – Minimum Plant Turbine output at rated head (1,625 feet net, ~2,700 cfs): **249 MW** (244 MW generator output) – Generator Plant Rated Output: **1,344 MVA** with PF 0.90 (1,209.6 MW)

Alternative	Description
Alternative 3 (Max. Uprate)	Uprating the units to the maximum feasible capacity while keeping the lower operating limit at the current lower limit of 83 MW. The target uprate range is 50 – 60 MW per unit (150 – 180 MW for the entire plant). • Single Unit Operation: – Maximum Turbine output at min. head (1,430 feet, 3,185 cfs): **345 MW** (338 MW generator output) – Maximum Turbine output at rated head (1,625 feet net; 3,510 cfs): **433 MW** (424 MW generator output) – Maximum Turbine output at max. head (1,719 feet net; 3,461 cfs): **452 MW** (443 MW generator output) – Minimum Turbine Output at rated head (1,625 feet net, ~900 cfs): **83 MW** (81 MW generator output) – Generator Rated Output: **511 MVA** with PF 0.90 (460 MW) • Three Unit Operation: – Maximum Turbine output at min. head (1,430 feet, 9,555 cfs): **1,035 MW** (1,014 MW generator output) – Maximum Turbine output at rated head (1,625 feet net; 10,530 cfs): **1,299 MW** (1,273 MW generator output) – Maximum Turbine output at max. head (1,690 feet net; 10,383 cfs): **1,335 MW** (1,309 MW generator output) – Minimum Turbine Output at rated head (1,625 feet net, ~2,700 cfs): **249 MW** (244 MW generator output) – Generator Plant Rated Output: **1,533 MVA** with PF 0.90 (1,380 MW)

Alternative	Description
Alternative 4 (Max. Uprate w/ Wider Operating Range)	Same scope as Alternative 3 above, but also aiming to reduce the lower operating limit below the current lower limit of 83MW. Due to the increase in peak power output from 409 MW (from alternative 1) to 452 MW, it is deemed not feasible to also lower the lower limit at the same time. Hence, this alternative was excluded from further investigation early in the study. • Single Unit Operation: – Maximum Turbine output at min. head (1,430 feet, 3,185 cfs): **345 MW** (338 MW generator output) – Maximum Turbine output at rated head (1,625 feet net; 3,510 cfs): **433 MW** (424 MW generator output) – Maximum Turbine output at max. head (1,719 feet net; 3,461 cfs): **452 MW** (443 MW generator output) – Minimum Turbine Output at rated head (1,625 feet net, ~900 cfs): **83 MW** – Generator Rated Output: **511 MVA** with PF 0.90 (460 MW) • Three Unit Operation: – Maximum Turbine output at min. head (1,430 feet, 9,555 cfs): **1,035 MW** (1014 MW generator output) – Maximum Turbine output at rated head (1,625 feet net; 10,530 cfs): **1,299 MW** (1273 MW generator output) – Maximum Turbine output at max. head (1,690 feet net; 10,383 cfs): **1,335 MW** (1309 MW generator output) – Minimum Turbine Output at rated head (1,625 feet net, ~2,700 cfs): **249 MW** (244 MW generator output) – Generator Plant Rated Output: **1,533 MVA** with PF 0.90 (1,380 MW)

<table>
<tr><th>Alternative</th><th>Description</th></tr>
<tr><td>Alternative 5
(Variable Speed Unit)</td><td>One unit will be converted to a variable speed unit with a DFIM and a frequency converter as AC excitation for the rotor winding; the two remaining units would be as with Alternative 3.

While DFIM and AC excitation system (frequency converters) have been built and supplied for the size envisioned for the uprated units, there is limited comparable pricing data. Stantec has roughly adjusted cost estimates for static frequency converters from other projects to reflect the size envisioned for Helms; however, this cost was only intended to be used for the initial consideration of this option and is not based on the engagement of potential suppliers of the converter—which is recommended if this option were carried forward or investigated further. The cost for an AC excitation could be in the range of approximately $10 million and would add additional costs for the generator. In addition, the converter requires significant space inside the powerhouse, which would require significant excavation, installation and work and adds O&M needs for the plant.

Based on preliminary performance estimates, the benefit of a full frequency converter is expected to be minimal at Helms. Typically, the benefit of adjustable speed units is most valuable for reversible units, as they allow for input power regulation in pump mode. As the main goal for the Helms units is an increase of power output in generation mode, and pumping mode is only secondary, the primary benefit would be reducing the rough operating zone. As the cost of the frequency converter, DFIM and excavation of the powerhouse would be substantial while the potential benefits appear to be minimal, Alternative 5 was removed from consideration early in the study.
Units 1&2 Single Unit Operation:
Maximum Turbine output at minimum head (1,430 feet net; 3,185 cfs): 345 MW (338 MW generator output)
Maximum Turbine Output at rated head (1,625 feet net, 3,510 cfs): 433 MW (424 MW generator output)
Maximum Turbine output at max. head (1,719 feet net; 3,461 cfs): 452 MW (443 MW generator output)
Minimum Turbine Output at rated head (1,625 feet net, ~900 cfs): 83 MW (81 MW generator output)
Generator Rated Output: 511 MVA with PF 0.90 (460 MW)
Unit 3 (Variable Speed) Single Operation:
Turbine output at min. head (1,430 feet net; 4,230 cfs): 460 MW (450 MW generator output)
Turbine output at rated head (1,625 feet net; 3,725 cfs): 465 MW (455 MW generator output)
Turbine output at max. head (1,719 feet net; 3,480 cfs): 465 MW (455 MW generator output)
Pump operating range: 340 rpm to 378 rpm with output ranging from 282MW to 430MW at minimum head and 366MW to 430MW at max head
Generator output at max. turbine output: 511 MVA with PF 0.90 (460 MW).</td></tr>
</table>

Alternative	Description
Alternative 5 (Variable Speed Unit) (contd.)	• Three Unit Operation: – Maximum Turbine output at minimum head (1,430 feet net; 10,600 cfs): **1,150 MW** (1,127 MW generator output) – Maximum Turbine Output at rated head (1,625 feet net, 10,745 cfs): **1,331 MW** (1,304 MW generator output) – Maximum Turbine output at max. head (1,696 feet net; 10,402 cfs): **1,369 MW** (1,341 MW generator output) – Generator Plant Rated Output: **1,533 MVA** with PF 0.90 (1,380 MW) The preliminary variable speed operating range was taken from GE pre-dimensioning of Helms II DFIM presented to PG&E. Heads and flows for the variable speed unit were assumed to be equivalent to the upgraded units in Alternative 3.

Alternative	Description
Alternative 6 (Addition of New Unit 4)	The desired output increase of 150 – 180 MW of total plant capacity would be achieved by adding a new unit 4 to the existing powerhouse. The existing three units would be as with Alternative 1. A unit with firm generating capacity of 150 MW (i.e., generator output of 150 MW at minimum head of 1430 feet, wicket gates 100% open) has been selected for this alternative. Due to the immense cost and significant construction effort and lost generation required to extend the powerhouse cavern and water conveyance system for a new unit, this alternative was removed from consideration early in the study. Alternative 6 is only listed for completeness throughout this report and was not reviewed in detail. • Single Unit Operation (Units 1-3): – Maximum Turbine output at minimum head (1,430 feet net; 3,143 cfs): **336 MW** (329 MW generator output) – Maximum Turbine Output at rated head (1,625 feet net, 3,072 cfs): **379 MW** (371 MW generator output) – Maximum Turbine output at max. head (1,724 feet net; 3,118 cfs): **409 MW** (401 MW generator output) – Minimum Turbine Output at rated head (1,625 feet net, ~900 cfs): **83 MW** (81 MW generator output) – Generator Rated Output: **448 MVA** with PF 0.90 (403.2 MW) • New Unit 4: – Maximum turbine output at min. head (1,430 feet net; 1,403 cfs): **153 MW** (150 MW generator output) – Maximum turbine output at max. head (1,739 feet net; 1,514 cfs): **205 MW** (200 MW generator output) – Minimum Turbine Output at average head (1,587 feet net, 450 cfs): **45 MW** (44 MW generator output) – Approx. Generator Rated Output: **205 MVA** with PF 0.90 (184.5 MW) • Four Unit Operation: - Maximum Plant Turbine output at minimum head (1,430 feet net; 10,929 cfs): **1,158 MW** (1,134 MW generator output) - Maximum Plant Turbine output at max head (1,674 feet net; 10,865 cfs): **1,405 MW** (1,377 MW generator output) - Minimum Plant Turbine output at rated head (1,625 feet net, ~3,150 cfs): **294 MW** (288 MW generator output) – Generator Rated Output: **1,549 MVA** with PF 0.90 (1,394.1 MW)

Table 6 below summarizes the scope of work for each alternative. The scope is defined by three categories:

- Reuse – The equipment does not require any modification or replacement and can be reused as is.
- Refurbish – Refurbishment and/or modification of the equipment is required to meet the design criteria for the given alternative.

- New – The existing equipment needs to be replaced, either in-kind or with a new and uprated design.

Components identified with an asterisk (*) indicate the worst-case scope for this component, e.g., a component listed as New* may be able to be refurbished instead, subject to further analysis and condition assessment.

Note that the scope of work described in the columns for Alternatives 5 and 6 at the unit level aligns with the variable speed unit or the new Unit 4, respectively. As noted above, for Alternative 5, the fixed speed units would have the same scope of work as Alternative 3, and for Alternative 6, the existing three units would have the same scope as Alternative 1.

Table 6. Scope of Work for Each Alternative

Alternative	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5	Alt. 6
Lower Operating Limit (MW)	83	73	83	<83	190	45
Upper Operating Limit (MW)	404	404	450 - 460	450 - 460	460	204
Pump-Turbine						
Runner and Coupling	New	New	New	New	New	New
Headcover	Refurb	Refurb	Refurb	Refurb	Refurb	New
Bottom Ring	Refurb	Refurb	Refurb	Refurb	Refurb	New
Discharge Ring	Refurb	Refurb	New*	New*	New*	New
Shaft	Refurb*	Refurb*	New*	New*	New*	New
Stay Vanes & Spiral Case	Refurb*	Refurb*	Refurb*	Refurb*	Refurb*	New
Wicket Gates	New	New	New	New	New	New
Wicket Gate Operating Mechanism & Operating Ring	Refurb	Refurb	New*	New*	New*	New
Servo Motors	Refurb*	Refurb*	New*	New*	New*	New
Runner Band Drain Valves	New*	New*	New*	New*	New*	New
Turbine Guide Bearing	Refurb*	Refurb*	Refurb	Refurb	Refurb	New
Shaft Seal & Clean Water System	Refurb*	Refurb*	New*	New*	New*	New

Alternative	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5	Alt. 6
Governor	Reuse	Reuse	Refurb*	Refurb*	Refurb*	New
Draft Tube (conical section)	Reuse	Reuse	New*	New*	New*	New
Motor-Generator						
Stator Windings	New	New	New	New	New	New
Stator Core	New	New	New	New	New	New
Stator Frame	Reuse	Reuse	New*	New*	New	New
Rotor Poles	Reuse	Reuse	New	New	New	New
Rotor Spider	Reuse	Reuse	Reuse	Reuse	New	New
Rotor Rim	Reuse	Reuse	Reuse	Reuse	New	New
Brakes/Jacks and Brake Ring	New	New	New	New	New	New
Starting Motor Shaft and Upper Couplings	Refurb*	Refurb*	Refurb*	Refurb*	New	New
Generator Main Stub Shaft	Refurb*	Refurb*	New	New	New	New
Thrust & Guide Bearings	Refurb*	Refurb*	Refurb*	Refurb*	New	New
Combined Thrust and Guide Bracket	Refurb*	Refurb*	Refurb*	Refurb*	New	New
Upper Guide Bearing and Bracket	Reuse	Reuse	New	New	New	New
Foundation Soleplates	Reuse	Reuse	Refurb	Refurb	Refurb	New
General						
Civil-Structural Works	Reuse	Reuse	Reuse*	Reuse*	Refurb	New
Water Conveyance System	Reuse	Reuse	Reuse	Reuse	Reuse	New
Station Switchyard System						
Station Switchyard	New*	New*	New*	New*	New*	New*
Circuit Breakers	New*	New*	New*	New*	New*	New*
Disconnect Switches	New*	New*	New*	New*	New*	New*

Alternative	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5	Alt. 6
Buses (4 Categories)	New*	New*	New*	New*	New*	New*
High Voltage Cables	Reuse	Reuse	New	New	New	New
Capacitor Power Transformers and Line Traps	New*	New*	New*	New*	New*	New*
Lighting Arresters	New*	New*	New*	New*	New*	New*
Balance of Plant (BoP) Mechanical						
Depression Air System	Reuse	Reuse	Refurb*	Refurb*	Refurb*	New
Cooling Water System	Reuse	Reuse	Refurb*	Refurb*	Refurb*	New
Lubricating Oil System	Reuse	Reuse	Refurb*	Refurb*	Refurb*	New
Plant Drainage System	Reuse	Reuse	Reuse	Reuse	Reuse	New
Unwatering Systems	Reuse	Reuse	Reuse	Reuse	Reuse	New
Fire Protection Systems	Reuse	Reuse	Refurb*	Refurb*	Refurb*	New
BoP Electrical						
Starting Motor Transformers 11, 12, and 13	New	New	New	New	N/A	New
13.8 kV Station Service Bus (Starting Motor Bus)	New	New	New	New	New	New
13.8 kV Station Service Switchgear	New	New	New	New	New	New
Station Service Transformers 1, 2, and 3	New	New	New	New	New	New
Station Service Transformer 4	New	New	New	New	New	New
Station Service Transformer for Unit 4	N/A	N/A	N/A	N/A	N/A	New
480V Station Service Switchgear	Reuse	Reuse	Reuse	Reuse	Refurb	Refurb
Load Centers 1 to 10	Reuse	Reuse	Reuse	Reuse	Refurb	New
Emergency Diesel Generator	New	New	New	New	New	New
125VDC Station Power System	Reuse	Reuse	Reuse	Reuse	Refurb	Refurb

Alternative	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5	Alt. 6
UPS	Reuse	Reuse	Reuse	Reuse	Refurb	Refurb
Protection & Control System	Reuse	Reuse	Refurb	Refurb	Refurb	New
Cables and Raceways (Required for new replacement equipment for Alt 1 to 4, and for new equipment for Alt 5 and 6)	New	New	New	New	New	New
Grounding (Required for new replacement equipment for Alt 1 to 4, and for new equipment for Alt 5 and 6)	New	New	New	New	New	New
Main Bank Transformer						
Main Bank Transformers	New	New	New	New	New	New
Disconnect Switches, Iso Phase Bus, and Exciter Bus						
High Resistance Neutral Grounding Equipment	Reuse	Reuse	Refurb	Refurb	New	New
Excitation System: Exciter Power Potential Transformer (PPT)	New	New	New	New	N/A	New
Excitation System: Excitation Switchgear	New	New	New	New	N/A	New
Starting Equipment: Starting Motor	Refurb	Refurb	Refurb	Refurb	N/A	New
Starting Equipment: 5 kV Starting Bus	Reuse	Reuse	Reuse	Reuse	N/A	New
Starting Equipment: Starting Motor Selector Switches	Reuse	Reuse	Reuse	Reuse	N/A	New
Starting Equipment: Liquid Rheostat A	Refurb	Refurb	Refurb	Refurb	N/A	Refurb
Starting Equipment: Liquid Rheostat B	Reuse	Reuse	Reuse	Reuse	N/A	Reuse
Starting Equipment: Liquid Rheostat Selector Switches	Reuse	Reuse	Reuse	Reuse	N/A	Reuse
Isolated Phase Bus	Refurb	Refurb	New	New	New	New
Phase Reversing Switch (Not needed if Generator-Motor Circuit Breaker is installed)	Reuse	Reuse	New	New	New	New

Alternative	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5	Alt. 6
Generator-Motor Circuit Breakers	future option; not included in cost estimate				New (variable speed unit only)	New (Unit 4 only)

3.1 Alternative 1: No Uprate – Status Quo (83 MW – 404 MW)

Operating Envelope: (83-404 MW)

Discussion:

Alternative 1 is a status quo approach. With this approach the unit would receive a life extension with a new turbine runner (with similar operating characteristics, and without uprate) and refurbishment or replacement of other unit equipment to extend the life of Helms PSP by another 40 years. A new and modern runner and wicket gates with model test and no capacity increase would be specified for this option.

The Helms turbine runner's size is, physically, relatively small for its power output. For that reason, a turbine runner refurbishment option (with equipment refurbishment) is a theoretical option for this alternative. However, this option would carry risks surrounding shop repairs and welding with subsequent heat treatment – and we understand the existing runners have begun to show signs of fatigue cracking. Furthermore, this option still can carry relatively high costs in comparison to replacement or upgrades, however, and is fraught with risk that cracking in the runner blades might reoccur despite best heat treatment efforts. Also, the total length of time for the unit outage must be extended for the duration of the refurbishment because the refurbishment / weld repair period often affects the critical path of the outage. A replacement turbine runner would allow for a shorter critical path if the machining diameters, keyway machining, coupling alignment, crown seal machining, and alignment all went smoothly. Going with a new replacement runner is the best option for mitigating the above concerns and has been considered as 'base scope' for this alternative.

Keeping the pump-turbine the same or very near the same design as the original installation will benefit the plant in terms of extending the unit's life and will likely result in similar reliability of the pump-turbines after replacement. Pump-turbine reliability is, however, dependent on a number of factors and even though the pump-turbine would be kept the same, overall future long-term high reliability cannot be assumed or relied upon. It would be expected that the reliability would be similar to or perhaps better after a replacement or refurbishment, barring no new discoveries or introduced issues.

Replacing the runner, which addresses the current fatigue cracking concerns, also would allow for a modern design that takes advantage of CFD advancements to provide efficiency gains and possibly reduced cavitation risk for the future service life.

Features or Limitations:

Some features or limitations for this alternative or option are discussed below.

- Speed Rise and Pressure Transients
    - The speed of the machine and its overspeed would be kept near the same with a simple runner replacement where the original overall design is kept. Any slight modifications to the design would be expected to have only a minor effect on the overspeed and transient load cases.

- The turbine governor and the auto-control system for start-up and shut-down for pump, generate, and synchronous condense mode would likely not require any major modification or upgrades, with any improvements made then being simply to improve the present system against any known issues.

- Head
  - The unit operating range could be maintained without additional testing or issues related to head losses. The starting time, inertia, and surge performance would require little additional consideration, barring no pre-existing issues.
- Rotor Stator Interaction (RSI)
  - By keeping the unit’s rotating speed the same, as well as the number of turbine blades and wicket gates, while maintaining the same minimum distance between them, there would be little chance of introducing an RSI issue or failure mode.
- Cavitation
  - The rate of cavitation erosion or pitting on the blades per hours of unit operation would likely remain similar, with reports of maintenance being required about every 10 years, for a total of eight shifts of weld repair, or could potentially be improved. Stantec does not have information on how many pounds of weld is needed during this repair period, so we are not able to use the International Electrotechnical Commission (IEC) 60609 Standard to determine the severity for the existing pump-turbine. While a similar hydraulic design would be kept, minor improvements with respect to cavitation could be achieved by incorporating modern design practices that have been improved since the current runner’s 1970s vintage design.
- Partial Load Requirement
  - The ability to continue to operate at historic partial load power outputs would be more or less maintained barring any specific load limitation relating to the seal performance or unit vibration issues.
- Operation range and flexibility
  - One limitation of this alternative is that no uprate or improvement in operational flexibility would be realized.

Merits:

- Can extend the lifespan of the existing unit.
- Does not require turbine distributor or draft tube redesign or modifications.
- Low risk of introducing hydraulic issues such as RSI, higher load rejection penstock pressure, or high power output draft tube whirl.

- Minor improvements in efficiency can be obtained from the new runner for generating and/or pumping operation.
- Potential to optimize the minimization of cavitation erosion on the runner by redesigning the runner to prevent cavitation zones from contacting runner's surface (blades, lower band and runner cone) as part of the redesign. This would however require study, with model testing, to be certain of success.

Demerits:

- No improved changes to capacity factor or load dispatch.
- No performance or system responsiveness improvements.
- Refurbishment of generator and peripheral equipment needed to ensure improved unit reliability.
- Model testing costs. Model testing would be recommended to verify power output targets, cavitation areas, pressure pulsation, etc. for any replacement pump-turbine runner that differed from the original.
- No improvement was made for increasing the time between cavitation erosion repair maintenance done on the turbine runner itself. (Timing in between unit outages for weld repairs to the runner may not be improved.)

Scope of Work:

- General
  - Nondestructive testing and stress and fatigue (remaining life) analyses would be required for most major pump-turbine and generator-motor components to confirm the current assumptions of suitability for then future forty-year plus service life. Additionally, specialized electrical tests of the stator windings, stator core, and rotor poles will be required to confirm the reuse or refurbish recommendations.
- Pump-Turbine
  - The runner is replaced with a new runner, designed for similar ratings as the existing unit. For the purposes of relative comparison, Stantec has assumed a model test is executed with a single supplier in this scenario. New wicket gates and runner seals are similarly provided for an optimized hydraulic design.
  - The condition of the pump-turbine components is not fully known. However, given their age, refurbishment and repair to components would be needed to further extend service life.
  - All turbine components would be inspected, assessed, and refurbished with wear parts (i.e., bushings, seals) replaced. Though it may not be required, it is assumed bearings are rebabbitted.

- In-shop headcover and bottom ring refurbishment and line-boring is assumed for life-extension and for fit-up with new wicket gates, respectively.
- Unit realignment with some level of stationary component site machining would be needed to ensure alignment and erection criteria fulfilled for the remaining service life.

- Motor-Generator
  - The stator frame will be reused. It is expected some level of repair/modification could be required to incorporate the replacement core (and winding).
  - The stator windings will be replaced. U1 and U3 stators were rewound in 2003, and U2 in 2020, and are reportedly currently in good condition. Unit 1 and 3 would otherwise require life extension rewinds during the outage, and Unit 2 continues to have issues related to hot spots and poor thermal performance, and, after discussions with PG&E, it was decided that this alternative would include replacement of all three unit's windings. Foundation soleplates are recommended to be re-doweled for larger diameter to improve the safety factors against torque short circuit events based on Voith's calculation report. Stator center and soleplates foundation leveling corrections may be required.
  - The stator cores will be replaced.
  - The rotor poles will be cleaned, inspected, and reused. An FEA fatigue assessment should be performed for the pole end plates to review the reported coil gap issues.
  - For this alternative, it is assumed the rotor spider can be reused. However, a detailed operations and maintenance instructions (OMI) procedure will be required, and a mitigation plan conducted to identify potential design modifications and reinforcements on the existing spider at the critical locations in the case cracks would be developed along the remaining life of the component.
  - The rotor rim would be reused.
  - Regarding the brake/jacking system, considering the current issues with flatness, hot spots and fixation looseness, it is assumed the brake/jack system would be replaced. It is recommended to investigate electric assisted braking improve the brake performance.
  - The generator main shaft and stub shaft will be refurbished. Some areas may require refurbishment (skim cuts to true flanges) and minor modifications at location of changes in section, based on the FEA and fatigue analysis.
  - Thrust and guide bearings would be refurbished with pads and shoes rebabbitted. Special care on selection of suppliers with experience on water-cooled bearing for the thrust shoes will be required.
  - Bearing brackets will be reused or refurbished based on the results of inspections, NDT, and analyses.

- Generator foundation concrete inspections would be performed to identify signs of potential cracks.

- General
  - Civil-Structural Works
    - At this point, the recommendation is that all civil-structural works can be reused. Detailed assessments and mapping of any observed deteriorated areas will need to be performed and generalized minor repairs (grouting, patching, etc.) will be required in localized areas that have suffered minor deterioration.
  - Water Conveyance System
    - At this point, no significant work has been identified as required on the water conveyance system for Alternative 1.
  - TSV
    - New TSVs, rated at design pressure of 1,088 psi and design flow of up to 4,325 cfs, are currently being procured by PG&E as part of a separate TSV replacement project.
  - Draft Tube Gates
    - The existing draft tube gates require refurbishment due to ongoing reliability issues and a history of in-service failures. It is understood this work is being performed as part of a separate ongoing project.
  - Station Switchyard System
    - The condition of the station switchyard electrical equipment, circuit breakers, disconnect switches, high-voltage buses, capacitor power transformers and line traps, and lightning arresters is not fully known. The 230 kV SF6 type circuit breakers are overhauled and tested for reliable operation every three years, and annually checked for issues. However, given their age and frequent maintenance of circuit breakers, replacement of these equipment is needed to provide the desired future service life .
    - The condition of the existing 230 kV cables that are the primary connection between the powerhouse and the switchyard is not fully known. Absent additional information, the cables are assumed to be in good condition and could be reused as there are no records of cables operated in overloaded condition, having any major repairs or were out of service for extended period.
  - BoP Mechanical
    - For this alternative, since an in-kind replacement should have no/insignificant effect on BoP equipment, it is assumed the existing mechanical BoP equipment can be reused as-is – and no costs have been included for refurbishment or modification of mechanical BoP equipment. Equipment and system refurbishments/replacements would be

addressed as part of plant maintenance and not as part of the uprate/life extension program.

- BoP Electrical
  - The condition of the existing starting motor transformers #11, 12 and 13 is not fully known. Based on PG&E, the dissolved gas analysis (DGA) results show the transformers are healthy, but they cycle a lot when compared with past DGA results. To minimize unplanned outages from transformer failures due to age, and also to extend the service life of the transformers to the desired additional 40 years, it is recommended to replace the transformers as part of the life extension project.
  - It is assumed the 13.8 kV station service bus for units 1 to 3 is currently in good condition. However, it is likely the bus would require extensive modifications to the layout for connections to the new starting motor transformers, station service and exciter power potential transformers and 13.8 kV station service switchgear, so it is recommended to replace the existing bus with newly designed bus. Additionally, the starting motor bus between units should be removed if a new generator breaker is installed, as each unit could be started in pump mode from its own starting motor fed from its own 230kV breaker.
  - The 13.8 kV station service switchgears of units 3, 1 and 2 were replaced during the life extension outages in 2008/2009, 2010/2011 and 2013/2013, respectively. Based on general industry data, the switchgear could potentially have more than 20 years of service life left, and it is assumed they are in good condition and can be reused. However, they would still require replacement during the future desired 40 years service life, so after further discussions with PG&E, it was decided to include replacement of the 13.8 kV station service switchgear of all three units as part of this scope. Additionally, if the starting motor bus is removed, the switchgear of each unit should be re-worked to remove the starting motor breakers as they are not needed.
  - The condition of the existing station service transformers 1 to 4 is not fully known. It is assumed the oil-filled transformers 1 to 3 are in good condition. Based on general industry guidelines, The transformers 1 to 3 could potentially have an estimated 12 years of service life left. The dry type transformer 4 has been primarily used to supply power to the powerhouse loads and it has been in service for more than 38 years. After further discussions with PG&E, it was decided to replace all four transformers to minimize unplanned outages from transformer failures due to age, and to provide the desired 40-year future service life. Additionally, it is also recommended to consider less hazardous dry-type for transformers 1 to 3.
  - The condition of the existing 480V station service switchgear is not fully known. However, the switchgear was replaced in 2005 and may be in good condition and can be reused.

- The condition of the existing load centers 1 to 10 is not fully known. However, the load centers were recently replaced in 2005 and are reportedly in excellent condition and can be reused. The unit's auxiliary starters and contactors in the load centers may have to be refurbished or replaced with larger size and capacity for operation with an uprated unit.
- The diesel generator is in poor condition and was out of service in August 2023. This generator will be obsoleted and replaced with a new generator.
- The condition of the existing 125VDC station power system is not fully known. The vented lead acid (VLA) main and auxiliary battery banks were replaced in 2019. The battery chargers were replaced in 2017. It is assumed that the battery banks and chargers including power distribution panels should be in good condition and can be reused. Based on a preliminary evaluation, The 125VDC station power system should be adequate for the uprate capacity of 460 MW.
- The uninterruptible power supply (UPS) was replaced in 2013 and regularly maintained. The existing UPS should be in good condition and can be reused.
- The existing lighting system has reached the end of its service life and lighting fixtures are old technology and obsolete products. The lighting system should be replaced with energy efficient, environmentally friendly, and longer lifespan LED fixtures.
- The existing protective relays and controls for the units and main bank transformers have been refurbished and can be reused. The 230 kV switchyard protective relays and controls need to be refurbished and separated from the control room. Additionally, the existing protective relays and controls for the units, main bank transformers and switchyard will require modifications to the relay settings, tripping and synchronizing schemes, and control circuits and logic if a motor-generator circuit breaker is installed.

- Main Bank Transformer
  - The condition of the existing main bank transformers is not fully known. It is assumed the transformers are in good condition, as there are no records indicating the transformers were operated in overloaded conditions or having any major problems. Based on general industry guidelines, the transformers have an estimated 12 years of service life left. After further discussions with PG&E, it was decided to replace the transformers as part of life extension project to minimize unplanned outages from transformer failures due to age, and to extend the service life of the transformers to the desired future 40 years.
- Disconnect Switches, Iso Phase Bus, and Exciter Bus
  - The condition of the existing high resistance neutral grounding equipment is not fully known. An average expected service life of high resistance grounding equipment is 50 years and there is no record of the equipment having failed and undergone any major repair work, so it is assumed the equipment is in good condition and can be reused.

- The condition of the existing oil-filled PPT for each unit is not fully known. Based on general industry guidelines. each unit's PPT's have an estimated 12 years of service life left. It is assumed the PPT's are in good condition, as there are no records indicating the transformers were operated in overloaded conditions or having any major problems. After further discussions with PG&E, it was decided to replace the PPT's as part of life extension project to minimize unplanned outages from PPT failures due to age, and to extend the service life of the PPT's to the desired future 40 years.
- The condition of the existing excitation system switchgear for each unit is not fully known. However, the excitation system switchgear for unit 1 was replaced in 2012, for unit 2 in 2013, and for unit 3 replaced in 2009. There is no record of the excitation system having failed or undergone any major repair work after they were replaced, so it is assumed the equipment is in good condition. Based on general industry guidelines, the controller and power electronic components have 15 to 20 years of service life. After further discussions with PG&E, it was decided to replace the excitation system switchgear as part of the life extension project to minimize unplanned outages from excitation system controller, power converter or other components failure due to age, and to extend the service life of the excitation system to the desired goal of a future 40 years.
- Each unit's starting motor has been in service for 38 years and its condition is not fully known. The starter motor stator coil should be replaced as it has reached the end of its service life. The rotor coil should be inspected and tested according to the testing methodology defined in the IEEE to verify if it needs to be refurbished or replaced. The remaining components of the starting motor should be inspected to verify if any repair work is needed to extend the service life of the starting motor to another 40 years.
- The condition of the existing 4.76 kV non-segregated phase bus for the starting equipment is not fully known. It is assumed the 4.76 kV bus is in good condition. The bus has an estimated 12 years of service life left. While the average expected service life of a medium voltage non-segregated phase bus is 50 years, as long as the bus is maintained properly and not operated in overloaded condition, the bus typically lasts longer. The ampere rating of the bus is 150% of the required maximum load, so it was never operated in overloaded condition. The bus was energized for less than 11 minutes during the unit's pump mode start-up and then had a lot of time to cool down until the next pump mode start-up. Based on the above, it is assumed the bus is in good condition and can be reused.
- The condition of each unit's starting motor medium voltage motor operated selector switch is not fully known. The Unit 2 starting motor selector switch had caught on fire in 2018 when opened with voltage on it. The switch was opened due to a ground issue in the control circuit. While the average expected service life of a medium voltage motor operated switch is 35 years, as long as the switch is maintained properly and not operated with the bus energized, it typically lasts longer. Since the ampere rating of the switch is 150% of the maximum current it carries, and it is operated with the bus de-energized, it is assumed the switch is in good condition and can be reused. However, it is recommended, as an option, to

consider replacing the switches with breakers to provide safe and reliable operation during faults on the bus.

- The condition of the existing liquid rheostats A and B for the starting equipment is not fully known. The service life of a liquid rheostat is between 20 to 40 years dependent on manufacturer and maintenance. MKS Anlasser- und Elektrotechnik Gesellschaft mit beschränkter Haftung (GmbH) liquid rheostat may last 40 years while American Industrial Motor Service and HECO liquid rheostats have a 20-year service life. Liquid rheostat A at Helms was manufactured by GE and has been in service for 38 years and is reported to be in good condition and can be reused. Liquid rheostat B was manufactured by Pape & Olbertz GmbH and it was installed in 2015 so it should be in good condition and can be reused.
- The condition of the existing medium voltage motor operated selector switches for liquid rheostats A and B is not fully known. While the average expected service life of a medium voltage motor operated switch is 35 years, as long as the switch is maintained properly and not operated with the bus loaded, it typically lasts longer. Since the ampere rating of the switch is 150% of the maximum current it carries, and it is operated with the bus unloaded, it is assumed the switch is in good condition and can be reused. However, it is recommended, as an option, to consider replacing the switches with breakers to provide safe and reliable operation during faults on the bus.
- The condition of the existing isolated phase bus is not fully known. While the average expected life of an isolated phase bus is 50 years, as long as the bus is maintained properly and not operated in overload condition, it typically lasts longer. The bus will require minor modifications and refurbishments for connections to the new starting motor transformers. The bus layout will have to be modified if a motor-generator circuit breaker is installed. Based on the above, the bus should be refurbished if a motor-generator circuit breaker is installed.
- The phase reversal switches for units 1 and 2 were refurbished in 2014 and for Unit 3 refurbished in 2013 and it is assumed that they are in good condition and can be reused. The phase reversal switches may not be needed if a motor-generator circuit breaker is installed for each unit (see immediately below) as the breakers could provide the reversing of phases during generator and pump mode operations.
- The existing units do not have a motor-generator circuit breaker between the motor-generator unit and main bank transformer. It is recommended to install a motor-generator breaker between each motor-generator unit and its respective main bank transformer, as it will increase the reliability (protection of generator against system fed fault currents and step-up transformer against generator fed fault currents) and availability of starting motor for dynamic braking during generator shut-down, and power to station service equipment by keeping the 230 Kv switchyard unit breaker closed. Refer to the 13.8 kV station service bus, isolated phase bus, and phase reversal sections above for refurbishments and replacements required to this equipment if a motor-generator circuit breaker is installed.

Costs:

See section 5.0 for a detailed breakdown of the OPCC. The estimated total cost for alternative 1 is shown in Table 7 below.

Table 7. Estimated Total Cost for Alternative 1

		Total Cost Estimate (2023 million USD w/ allowance)
Alternative 1	low	142.4
	mid	**203.5**
	high	305.2

Relative Rankings:

- Construction Cost: Low (Rank: 1st)
- O&M Cost Consideration: Medium (Rank: 3rd)
- Outage Duration: Low (Rank: 1st)
- Expected Reliability: Low (Rank: 5th)
- Risks: Low (Rank: 1st)
- Best Technical Solution: Medium (Rank: 4th)
- Amount of Integration Work: Low (Rank: 1st)
- Expected Benefit: Low (Rank: 6th)

3.2 Alternative 2: Status Quo – Wider Operating Range (<83 MW – 404 MW)

Operating Envelope: (73-404MW)

Discussion:

This alternative is identical to alternative 1 in many ways, but it attempts to widen the existing operating range by lowering the lower limit below 83 MW. An enhanced pump-turbine runner design that has a lower minimum operating range and similar or near higher maximum power output operating range may be feasible. Enabling the Helms units to operate more stably at lower power outputs while avoiding excessive cavitation and excessive radial shaft vibration and/or pressure pulsations would be the main objective. A turbine OEM could conduct a CFD study or apply their internal expertise using similar units to determine feasibility. Once verified, model testing and a hydraulic study would be needed to finalize a suitable replacement design. Implementation would be similar to Alternative 1, with potentially additional schedule time needed for additional studies / design.

Limits:

Same as alternative 1 except for the following:

Recent work on conventional Francis units has allowed operation down to or near speed-no-load, but requires additional study, testing (i.e., specialty strain gauge measurement on both model and prototype runners), and a more robust design. However, Stantec is not aware of reversible Francis pump-turbines with similar size/head to that of Helms that allow continuous operation down to these low outputs; even the 20% output that Helms currently operates to is quite impressive – but very unusual, in our experience. As such, narrowing of the pump-turbine runner's current performance issues in terms of the rough zone and draft tube vortex at off-design operation, while extending downward the low load operating limit will require significant study – technical analyses including fluid dynamics, stress, and fatigue, and comprehensive physical model testing. It is possible that after the study, however, there may be little or no gains to be made for lowering further the operating power output below 83 MW. Regardless, any operation at these low loads (likely even the current operations) will include operation through interblade vortices and increased vibrations, increasing overall wear and tear. Based on preliminary review, a nominal improvement of 73 MW has been assumed for this alternative, however this will need to be confirmed by the OEM through CFD analysis and model testing.

Merits:

- Potential to increase the unit's annual capacity factor from expansion of the turbine's operating envelope (generate mode only). This is also subject to market demand.
- Similar to Alternative 1, potential to optimize the replacement runner design for cavitation performance.

Demerits:

- Would not be adding additional power to the grid in terms of maximum net demonstrated power output for the plant.
- Model testing costs. Model testing would be required to verify power output targets, cavitation areas, pressure pulsation, etc. for any replacement pump-turbine runner that differed from the original.
- It is difficult to guarantee that lower power output limits could be achieved. Existing minimum output levels (~20% max output) would be already considered low in comparison to typical pump-turbine operation. There is a possibility that redesign could restrict unit operations at other partial load power output levels that are not presently restricted. (Higher vibration or shaft peak-to-peak run out possible at higher partial loads.). Additionally, as part of the changes needed to lower the minimum operating output, suppliers may impose lower or more restrictive limits on maximum outputs, offsetting or negating the benefits of lower power outputs.

Scope of Work:

- Pump-Turbine
  - Pump-Turbine model testing with objective of expanding the operating envelope. A study to determine probable lower operating limit would be required, unless the turbine manufacturer had a demonstratable way to show its feasibility like with a similar unit in terms of head, and power in their internal unit catalog, or reference projects. Suppliers may suggest additional model testing efforts, including instrumentation of model runner with strain gauges (and again in field on prototype) to study effect of deep part load operation.
  - For this alternative, pump-turbine scope of work for Alternative 2 is assumed identical to Alternative 1. Given the aims of this alternative, the following might reasonably be considered by OEMs, but have not been considered in the cost estimate.
    - The turbine manufacturer might recommend modifications to the turbine inlet geometry, including possibly the spiral case, the turbine distributor (stay ring and stay vanes), and wicket gates for a larger operating envelope. Modifications to the discharge ring, the head cover, the draft tube, and the turbine runner may also be needed.
    - Draft tube modification may still be required despite no large power output gains in turbine mode. Anti-vibration air system modification may be required to help lower the minimum range; however, it would be largely unverified until expensive testing was completed.
- Motor-Generator
  - Scope of work is identical to Alternative 1.
  - Review the rotor dynamics calculations with the updated new hydraulic loads (radial and axial).

- General
  - Civil-Structural Works
    - Scope of work is identical to Alternative 1.
  - Water Conveyance System
    - Scope of work is identical to Alternative 1.
  - TSV
    - Scope of work is identical to Alternative 1.
  - Draft Tube Gates
    - Scope of work is identical to Alternative 1.
  - Station Switchyard System
    - Scope of work is identical to Alternative 1.
  - BoP Mechanical
    - Maintaining the existing maximum power output of the turbine should permit the existing BoP equipment to be maintained or reused with minimal modifications needed. Therefore, as done for Alternative 1, no specific project costs related to the BoP mechanical equipment are included for this alternative.
  - BoP Electrical
    - Scope of work is identical to Alternative 1.
- Main Bank Transformer
  - Scope of work is identical to Alternative 1.
- Disconnect Switches, Iso Phase Bus, and Exciter Bus
  - Scope of work is identical to Alternative 1.

Costs:

See section 5.0 for a detailed breakdown of the OPCC. The estimated total cost for alternative 2 is shown in Table 8 below.

Table 8. Estimated Total Cost for Alternative 2

		Total Cost Estimate (2023 million USD w/ allowance)
Alternative 2	low	142.4
	mid	**203.5**
	high	305.2

RELATIVE RANKINGS:

- Construction Cost: Low (Rank: 1st)
- O&M Cost Consideration: Medium (Rank: 3rd)
- Outage Duration: Low (Rank: 2nd)
- Expected Reliability: Low (Rank: 6th)
- Risks: Low (Rank: 2nd)
- Best Technical Solution: Low (Rank: 6th)
- Amount of Integration Work: Low (Rank: 2nd)
- Expected Benefit: Low (Rank: 5th)

3.3 Alternative 3: Uprate to Maximum Feasible Capacity (83MW to 450-460 MW)

Operating Envelope: (83 MW to 450-460MW)

Discussion:

With a redesign of the turbine runner, turbine power output at Helms can be progressively increased with modifications to the runner hydraulic design, turbine discharge diameter and upper draft tube diameter. It may also be possible to maintain (or nearly keep) the present minimum power output with these modifications, if the design is made along the lines of the "Hitachi Plan A" methodology.

Model testing, to determine the power operating envelope and hydraulic turbine characteristics will be required to realize and validate the design with confidence and to investigate hydraulic phenomena that could be encountered if the uprate is not carefully planned and designed (RSI, overload surge, cavitation).

With a unit uprate per the Hitachi Plan A, it is expected that the turbine power output could be increased perhaps up to around 450-460 MW. Construction time for performing this option is nearly optimized compared to other options in that major concrete and civil modifications to the plant are primarily focused on the draft tube and bracket sole plates, and the existing spiral case and turbine inlet diameter can be held without major demolition and reconstruction. It should be reasonable to complete such an outage within about one (1) year to one and half (1.5) years of construction. The construction phase will be dependent on resources and pre-planning activities, as well as extent of pump-turbine embedded part modification.

The advantage of this option is that the size and shape of the inlet and distributor, which are the parts that control the flow of water into the turbine, do not need to be changed. The theoretical work done by Hitachi shows that the units could perhaps achieve a turbine power increase to around 450-460 MW by just changing the outlet and draft tube geometry. This means that we can also minimize any modifications and changes to the turbine head cover also (other than modifications required for improved runner seals).

As part of the engineering design phase, the design would need to be tested on a model to make sure its power output and hydraulics would be as predicted (i.e. measurement of the power operating envelope at different water flows and head ranges). Measurement of the hydraulic pump and turbine characteristics, which are the performance indicators of the machine, such as efficiency, pressure pulsation and fluctuation, axial thrust, cavitation, draft tube discharge whirl, etc. would all be done as part of the model testing to validate acceptable operation over the new, expanded range.

Turbine manufacturers may recommend turbine distributor design modification to permit a more powerful turbine. Potential modifications include: the stay ring, stay vanes, wicket gates, discharge ring and upper draft tube design. With a new turbine geometry, the headcover, and lower runner band diameters, as well as the seal design might be altered for Helms such that the turbines discharge diameter is increased slightly.

Limits:

- Maximum Power Output
  - The maximum power output from the turbine will be dependent on the turbine blade optimization, discharge outlet diameter, seal modifications and modifications made to the draft tube for power recovery. The extent of draft tube modification with the new turbine runner blade profiles will govern largely the max. power achieved. It is expected that the maximum power from the turbine will be around 450-460 MW.
  - Model testing is required to confirm the power output is achievable.
  - Depending on the manufacturer, modification to the stay vanes may be recommended to prevent cavitation erosion issues on the turbine, and for small power output improvement (efficiency gain). As such, one of the key limitations is turbine inlet geometry.
- Flow
  - Increasing power output of Units 1 to 3 by approximately 45 to 55 MW each will require an increase in flow going through the turbines. Maintaining the present penstock diameters as they are now while increasing the power output toward a higher value will require increases in the water velocity through the penstock. The turbine OEM will need to verify maximum feasible power output against the conveyance system friction losses for the higher flows while keeping the turbine centerline elevation at its present value.
- The management of the net head between Courtright Lake and Lake Wishon will limit the possible turbine design parameters. Historic operations and reservoir management will be a limiting factor in the redesign of the system.

Merits:

- Increase in power and net demonstrated capacity for plant.
- Potential for reduced construction costs and work schedule duration because of compatibility for upgraded turbine runner to work with existing spiral case and distributor geometry (per Hitachi reported options A or B). Note however that other OEMs may recommend distributor modification.
- Depending on the final design, it may be possible to improve turbine efficiency at strategic operating power outputs.
- Renewed lifespan and reliability for replaced components.
- Minor equipment modification costs for shaft system and generator relative to complete replacements if the turbine’s power output is kept under 460 MW range.

Demerits:

- Initially the upfront project cost can be higher because of the expense for model testing, however once completed the plants higher net demonstrated power output would offset this cost and provide opportunity for increased power generation revenue.
- Modification to the draft tube and discharge ring is likely necessary to accommodate new turbine outlet diameter and discharge flows, which can increase project outage duration relative to Status Quo (Alternative 1) approach.

Scope of Work:

- Pump-Turbine
  - Competitive model test.
  - Manufacture of a new pump-turbine hydraulic design, different than the original with a slightly larger runner discharge diameter and revised turbine blade depth and profiles, and new wicket gates with optimized hydraulic profiles .
  - Modification of the discharge ring and draft tube, with an assumption of modification to the upper draft tube, similar to Hitachi Plan A methodology. It is not expected that modification of the elbow and horizontal section of the draft tube would be economical and is not considered.
  - Turbine Guide Bearing modification may be required.
  - Lower runner band seal with lower runner band drainage piping and valve modifications.
  - While it is possible the existing shaft may be reused and refurbished (as done for Alternative 1), a new shaft is considered for increased torque requirements and to reset fatigue life. Subsequently, a new shaft seal is included in this alternative.
- Motor-Generator
  - The scope of work is similar to Alternative 1 for the proposed components to be reused/refurbished: rotor spider and rotor rim, main shaft, thrust and guide bearings and combined thrust bracket. Special considerations on the reused/refurbished components and new generator components required to reach the new uprated power are described below.
  - Some of those components with critical areas identified by FEA would be MT and UT inspected. Repairs, modifications, reshaping and design improvements may be necessary to reset and extend the fatigue life considering the higher loads due to achieve the targeted upgrade.
  - Bearings would be refurbished and rebabbitted.
  - The new stator windings would be designed based on the U2 electrical design improvements with the same quantity of copper cross section. Dielectric distances would be improved with circular shape stator winding circuit rings instead of polygonal shape. Special

FEA is required to avoid induction heating at the terminal regions and may require magnetic shield against metallic parts on the stator frame. FEA calculations would be performed to ensure no harmful vibrations at the winding's overhangs. Verify possibility to reduce the weight of the bar water couplings and connections. Review the cooling water hydraulic circuit with the new proposed design by Voith and confirm the new layout for the water distribution manifold around the stator.

- The new stator core and clamping system would be designed to allow free thermal expansion, to keep clamping pressure, avoid buckling. Perform natural frequencies and resonance analysis to confirm no harmful vibration may occur. Design improvements regarding material grade and air gap. Preferably, the core would be continuously stacked. A study on the powerhouse space availability is required, identifying lifting device, work platforms and to establish the logistic plan.
- A new stator frame was recommended/assumed for this alternative. However, rehabilitated versus new stator frame options could be investigated for this alternative. Recent experiences with modernization projects reveal significant benefit/justification for new stator frames due to high construction and risk costs for refurbishment of stator frames to accommodate an uprate. The stator frame design will accommodate the new core clamping system and the new interfaces with the newly proposed upper bracket design.
- New poles are proposed to overcome the existing temperature limits of the existing field coils and the damper windings, also to resolve the existing issues with the gaps at the pole end plates and paper migration. New air baffles would be placed between adjacent poles to improve the ventilation similar in concept with the original Westinghouse solution to ensure temperature under allowable limits. New V-blocks are required to limit the coils tangential deformation, designed to facilitate maintenance, and would allow a pole to be removed without removal of the rotor. New damper windings would be designed to allow the required thermal expansion.
- New brake segments would be designed with thicker thickness to replace the existing ones with an improved fixation system and to be assembled considering the existing rotor spider and rim. Brake calculations with the new turbine hydraulic curves and optimization studies would be performed to validate electrical assisted braking operation to reduce the excessive heating on the brake segments and the overall braking time. New brake jacks are recommended with technical and economic advantages over refurbishing of the existing ones.
- Review the rotor dynamics calculations with the updated new hydraulic loads (radial and axial). The existing vibration levels are in the upper boundary limits. Therefore, a new upper guide bracket and supporting system is recommended for the uprate condition to improve rotor dynamics.

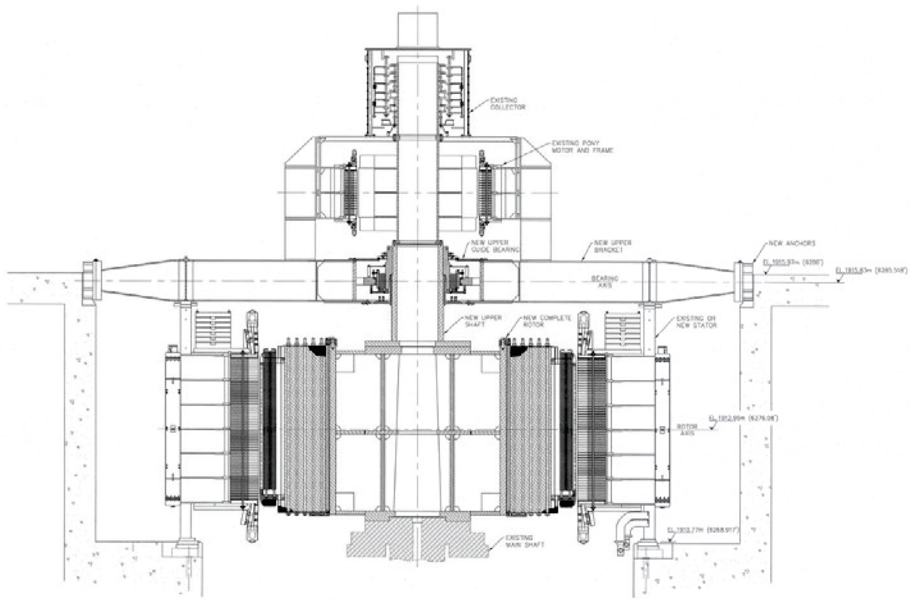


Figure 13. New Upper Bracket and Upper Guide Bearing

- New upper bracket and guide bearings would be designed to be on top of the stator frame to reduce the bearing center line to the magnetic centerline distance. A special supporting system would be designed to avoid excessive thermal forces on the concrete while increasing the dynamic stiffness response to the generator loads in all operating conditions. A detailed FEA study would confirm the expected performance of the newly proposed layout.
- New stub shaft to accommodate the new proposed layout for the upper guide bearing to improve the shaft dynamics.
- Integrate and harmonize the required modifications on the slip rings, excitation leads, pony motor and civil structure to accommodate the new upper bearing layout.
- Additionally, refer to the Engineering Assessment Report for detailed recommendations.

- General
    - Civil-Structural Works – In general, civil-structural works will be reused. However, specific localized refurbishment or strengthening may be required to accommodate larger dimensions and-or higher loads as itemized below.
        - It is necessary to evaluate the concrete around embedded draft tube sections that require widening.
        - Structural evaluations of existing foundations for all equipment that require upgrade will need to be performed.

  - New foundations may need to be added for any new machining tools required to complete on-site refurbishment such as lathe or cutting equipment.
  - New compressors may require new mounts or pedestals.
  - It will be necessary to evaluate the increase of existing stator sole plate pockets for addition of new radial dowels.
  - In case of isophase bus uprates it will likely be necessary to replace duct mounting and internal stand of pedestals.
  - Existing TSV concrete pedestals need to be evaluated for new TSV loads. This scope of work is already covered in the TSV replacement project.
  - It is recommended to evaluate and analyze the existing intake / discharge structure trash racks for higher flows as well as to perform existing intake / discharge structures concrete condition assessment and concrete scour potential evaluation, in consideration of increased flows.
  - It is recommended to perform a detailed condition assessment of the existing Tunnel 1 Gate Shaft.
  - It is recommended to perform a detailed condition assessment of existing gate to determine gate remaining life.
  - It is necessary to perform gate hydraulic pull-down or transient uplift force analysis against new flows as well as gate loading ability to drop under full load in emergency gate drop situation.
  - It is recommended to perform gate gains and roller path checks.
  - The intake gate hoist floor should be evaluated for higher hydraulic downpull forces.
- Water Conveyance System
  - The scope of work for the water conveyance system is limited to engineering scope (e.g., analysis & condition assessment) to confirm higher uprate flows can safely be achieved.
  - No work to the existing water conveyance system is expected for this alternative.
- TSV
  - Scope of work is identical to Alternative 1.
- Draft Tube Gates
  - Scope of work is identical to Alternative 1.
- Station Switchyard System
  - Scope of work is identical to Alternative 1 except for the following:

        - The existing capacity of the 230 kV oil-filled paper-insulated cables connecting the generator step-up (GSU) transformers to the switchyard will not be adequate for the uprate capacity of 460 MW / 511 MVA and should be replaced.

  - BoP Mechanical

    - The current recommended scope is general refurbishment with select minor modifications. However, with increased turbine and thus generator power output, there will be additional generator heat produced at the core winding (what is sometimes referred to as the I^2R losses). This added heat is absorbed with the stator's surface air coolers, and winding cooling water system. As such, the cooling water system used for cooling the generator stator, and the thrust and radial guide bearings will need to be evaluated for cooling capacity. The available, and anticipated water temperature and flowrate will need to be confirmed and compared to the anticipated new cooling water requirements. Also, cooling for the excitation system, transformer, and liquid rheostat will also need to be evaluated. From discussions with PGE, we understand there is ample reserve cooling water supply (standby pumps) that could be utilized if required. It is possible that cooling water pump, filter and piping systems may need to be modified to accommodate the increased demand for cooling from the new unit and supporting equipment.
    - In consideration of the existing issues (e.g. aging pumps/piping) that would be addressed regardless of alternative, only a minor cost allowance is assumed for this alternative, to account for potential modifications to piping servicing the unit as required by changes to associated P-T / M-G components (i.e. bearing cooling, stator coolers, depression air, fire piping to generator).

  - BoP Electrical

    - Scope of work is identical to Alternative 1 scope of work except for the following:

      - The existing protective relays for the units and main bank transformers may require modifications to the relay settings for an uprated unit.

- Main Bank Transformer

  - The existing main bank transformers will be replaced with a higher MVA rating required for the uprated units.

- Disconnect Switches, Iso Phase Bus, and Exciter Bus

  - Scope of work is identical to Alternative 1 scope of work except for the following:

    - The size of the neutral grounding transformer and resistor will be evaluated to verify if they need to be refurbished for operation with uprated unit, which will have higher zero-sequence capacitive reactance, and to meet the duration of the short-time overload factor in the original design criteria.

- The existing isolated phase bus will be replaced with a higher ampere rating required for the uprated units.
- The existing phase reversing switch will be replaced with a higher ampere rating required for the uprated units. The phase reversal switches may not be needed if a motor-generator circuit breaker is installed for each unit as the breakers could provide the reversing of phases during generator and pump mode operations.

Costs:

See section 5.0 for a detailed breakdown of the OPCC. The estimated total cost for alternative 3 is shown in Table 9 below.

Table 9. Estimated Total Cost for Alternative 3

		Total Cost Estimate (2023 million USD w/ allowance)
Alternative 3	low	218.2
	mid	**311.8**
	high	467.7

RELATIVE RANKINGS:

- Construction Cost: Medium (Rank: 3rd)
- O&M Cost Consideration: Low (Rank: 1st)
- Outage Duration: Medium (Rank: 3rd)
- Expected Reliability: High (Rank: 1st)
- Risks: Medium (Rank: 4th)
- Best Technical Solution: Medium (Rank: 3rd)
- Amount of Integration Work: Medium (Rank: 3rd)
- Expected Benefit: Medium (Rank: 4th)

3.4 Alternative 4: Uprate to Maximum Feasible Capacity with Wider Operating Range (<83 MW to 450-460 MW)

Operating Envelope: (83 MW to 450-460 MW)

Discussion:

The feasibility of lowering the lower operating limit while at the same time increasing the upper operating limit is deemed unlikely. This is due to inherent hydraulic design limitations in a single hydraulic design that must accommodate both pumping and generation. Steep efficiency drop-offs, rough operating zones, and potential four-quadrant operational limitations across the operating range of heads constrain the ability to widen the operating range at both ends. It is not expected that it is possible to lower the current lower limit below 83 MW. Hence, this alternative was excluded from further study early in the process. The below discussion is intended to provide a high-level summary and explanation for why this alternative is deemed not feasible.

Expansion of the operating envelope with a runner redesign will alter the unit's rough zone or Rough Load Zone (RLZ), which is the range of power output where additional turbine vibration and pressure pulsation occurs which are translated to and felt in the turbine and shaft system axially and radially. Typical rough zone instability can occur between the 30 to 50% partial load range and in some instances up into the 70% region. Presently the units can be operated at around 83 MW for low load operations – which is reflective of the [redacted] paper[1] mentioning that there is a "no-Run zone" below 80 to 100 MW (depending on head) defined by inlet turbulence. The paper further describes the extent of the typical rough zone between approximately 150-230 MW (i.e., about 40-60% load), and notes that "the runner is "happy" at about 300 MW in the Gen direction, basically at its "Design Point". In the "overdrive" section of the curve, between about 330-400MW, the unit behaves like a Francis runner operating above its design point wicket opening, with increased turbulence throughout."

From discussions with Hitachi in September 2023, it was understood if an option such as their Plan A was undertaken then it might be possible to maintain a minimum power output near 83 MW. It was also mentioned that in going with a power output larger than 460 MW using the current runner's inlet dimensions, that a high load draft tube torch would occur and prevent smooth operation of the unit despite a theoretical upper power limit.

Shifting the design point "upwards" with a replacement turbine with increased power outputs may then result in reduced range or options for low load operations.

Lowering the stable minimum power output while increasing the maximum power output is unlikely, but verification of this is difficult to determine outside of model (and prototype) testing. Also, by attempting to totally maximize the power output other operating regions which the plant typically operates at might be eliminated, reduced, or shifted by the new replacement design.

[1] [redacted] "HELMS CREEK MECHANICAL HISTORY 1984-2018". May 12, 2020.

Limits:

- A maximum power output for the turbine bordering around 450-460 MW is noted by Hitachi if the present inlet geometry is kept due to high load draft tube whirl introduction (also referred to as high load draft tube torch effect).

Merits:

- Increased unit and plant maximum power output.
- Increased efficiency for pump mode and generate mode with new analysis applied.
- Improved stability for a minimum load power output for each unit.
- Widening of operating envelope for plant in general. (*Noting that there may be new power output regions however which are not utilizable due to the new RLZ range.)

Demerits:

- Additional study required by turbine OEM to determine low load limit power output and new RLZ.
- Possibility for the introduction of new hydraulic operating phenomena such as RSI, and or expansion of the RLZ.

Scope of Work:

- Pump-Turbine
  - General scope is identical to Alternative 3.
- Motor-Generator
  - Scope of work is identical to Alternative 3.
- General
  - Civil-Structural Works
    - Scope of work is identical to Alternative 3.
  - Water Conveyance System
    - Scope of work is identical to Alternative 3.
  - TSV
    - Scope of work is identical to Alternative 1.
  - Draft Tube Gates
    - Scope of work is identical to Alternative 1.
  - Station Switchyard System

    - Scope of work is identical to Alternative 3.
  - BoP Mechanical
    - Sope of work is identical to Alternative 3.
  - BoP Electrical
    - Scope of work is identical to Alternative 3.
- Main Bank Transformer
  - Scope of work is identical to Alternative 3.
- Disconnect Switches, Iso Phase Bus, and Exciter Bus
  - Scope of work is identical to Alternative 3.

Costs:

See section 5.0 for a detailed breakdown of the OPCC. The estimated total cost for alternative 4 is shown in Table 10 below.

Table 10. Estimated Total Cost for Alternative 4

		Total Cost Estimate (2023 million USD w/ allowance)
Alternative 4	low	218.2
	mid	**311.8**
	high	467.7

RELATIVE RANKINGS:

- Construction Cost: Medium (Rank: 3rd)
- O&M Cost Consideration: Low (Rank: 1st)
- Outage Duration: Medium (Rank: 4th)
- Expected Reliability: High (Rank: 2nd)
- Risks: High (Rank: 5th)
- Best Technical Solution: Low (Rank: 5th)
- Amount of Integration Work: Medium (Rank: 4th)
- Expected Benefit: Medium (Rank: 3rd)

3.5 Alternative 5: Variable Speed Unit

Operating Envelope: (190-460 MW)

Discussion:

A variable speed pump-turbine unit has advantages over fixed speed pump-turbines in that it can provide ancillary services to the grid such as frequency regulation, voltage support, and load regulation or following during pump mode, as well as improved efficiencies, a smaller rough operating zone, and slightly improved operating range during turbine mode. A variable speed unit will have higher equipment costs than the other options (initial investment cost) for Helms for the additional procurement and placement for the electrical equipment needed for the variable speed control systems. Additional civil costs will be incurred due to the heavy civil work required to excavate space to accommodate the large bank of new electrical variable speed equipment.

Preliminary variable speed data for the expected operating range and speed range have been provided previously in a Helms II pre-dimensioning presentation by GE and is in line with our understanding of the project goals and typical variable speed performance – and has been assumed for this alternative analysis. For incorporation of a variable speed unit into the existing turbine casing at Helms, the unit will need to be designed in consideration of the desired operating criteria, existing pump-turbine setting, and head and tailwater ranges, to determine the nominal and range of operating speeds and allowable continuous operating range in turbine and pump modes.

Variable speed operation can be accomplished by using a fully fed frequency converter with a conventional synchronous salient pole unit or through a DFIM with an AC excitation system.

Typically, a full converter with synchronous machine is used for lower output range while DFIM with AC excitation is used on high output range. Currently, the breakeven point between those options is in the range of 120MVA-150MVA. The largest plant with full converter and synchronous machine in operation is Grimsel 2, in Switzerland rated 100MVA and went in commercial operation in 2013. Since then, several others pumped storage plants with full converter were commissioned, all below 100MVA output. For instance, Limberg (2 x 81.5MVA) in 2018, and Malta Oberstufe (2 x 86MVA) in 2022, among others. Several new units are scheduled to be installed in the next several years with outputs up to 130MVA.

Although converter manufacturers claim that full converters up to 300MVA are possible by connecting several units in parallel, this is not a proven concept yet and requires substantial space.

DFIM with AC excitation is a proven technology in operation since the 1990s. In the last 20 years, the lowest output for a DFIM with AC excitation was Nand-De-Drance in Switzerland (175 MVA) and the highest output was Kazunogawa in Japan (475 MVA).

A Helms variable speed unit with 460 MW output falls at the installed limit for DFIM with AC excitation and would be outside of the current experience with full converter and conventional synchronous machine.

Limits:

- Variable speed pumped storage units with DFIM and AC excitation are typically larger in size than the corresponding synchronous motor-generator, which means a DFIM unit of the same size as a synchronous motor-generator will produce less power. The typical derating range is 10% to 15%. Thus, if Helms generator components are reused, such as stator frame, rotor spider, etc., in comparison to a 460 MW fixed speed unit, the output will be derated to 390 MW for a variable speed unit. This condition does not meet the PG&E goal of uprating the Helms facility.
- To maintain the desired increase in power output, the motor-generator will have to be replaced and most likely the new unit rotor will be longer and heavier, and will have a three-phase collector ring assembly substantially taller than the existing collector ring assembly.

Merits:

- Ancillary Services such as the ability to load follow in pump mode. (i.e., ability to operate at a range of power inputs for pump mode)
- Possibility for improved hydraulic efficiency.

Demerits:

- The elevation of the runner may need to be lowered to optimize Net Positive Suction Head (NPSH) and for cavitation reasons if the design chosen is permitted to incorporate a higher speed than the existing synchronous speed. There have, however, been fixed-to-variable speed conversions that maintain existing unit centerline. For this study, it is assumed the existing centerline is maintained and the existing embedded components are reused.
- Increased maintenance costs for units.
- Heavier and taller rotor that may require bridge crane upgrade.
- Large room for AC excitation equipment and excitation transformers.
- Isolated phase bus for field winding excitation.

Scope of Work:

- Pump-Turbine
  - Scope of work is nearly identical to Alternative 3, with a few caveats as follows.
  - One unit would be converted to variable speed, while the other two remain fixed speed. On the pump-turbine side, the design could be identical such that the same hydraulic design is provided for each of the three units, such that future conversion to variable speed would be possible for the two fixed speed units.
  - Competitive pump-Turbine model testing would be completed and would be slightly more extensive to investigate variable speed performance.

- Motor-Generator
  - Scope of work for two units would be identical to Alternative 2.
  - For the third unit, a complete new variable speed DFIM motor-generator would be provided.
- General
  - Civil-Structural Works
    - Existing concrete demolition
    - Concrete works
    - New equipment foundations
    - Excavation of room for AC excitation equipment and excitation transformers.
  - Water Conveyance System
    - Scope of work is identical to Alternative 3.
  - TSV
    - Scope of work is identical to Alternative 1.
  - Draft Tube Gates
    - Scope of work is identical to Alternative 1.
  - Station Switchyard System
    - Scope of work is identical to Alternative 3.
  - BoP Mechanical
    - Scope of work would be the same as Alternative 3, except that additional flows would be required to service the new variable speed electrical equipment.
  - BoP Electrical
    - Scope of work is identical to Alternative 3 scope of work except for the following:
      - Starting motor transformer is not applicable for this alternative.
      - The existing 480V station service switchgear will be refurbished or replaced to include loads for a variable speed unit.
      - The existing load centers will be refurbished or replaced to include loads for a variable speed unit.
      - The existing 125VDC station power system will be refurbished or replaced to include loads for a variable speed unit.

        - The existing UPS will be refurbished or replaced to include loads for a variable speed unit.

- Main Bank Transformer
    - The scope of work is identical to Alternative 3.
- Disconnect Switches, Iso Phase Bus, and Exciter Bus
    - Scope of work is identical to Alternative 3 scope of work except for the following:
        - A new high resistance neutral grounding equipment is needed for operation with variable speed unit, which may have higher zero-sequence capacitive reactance, and to meet the duration of the short-time overload factor in the original design criteria.
        - A new AC excitation transformer and converter is needed for variable speed unit.
        - Starting equipment indicated for other alternatives is not applicable for variable speed unit.
        - A new isolated phase bus for field winding excitation connecting the three-phases collector rings to the AC excitation system.

Costs:

See section 5.0 for a detailed breakdown of the OPCC. The estimated total cost for alternative 5 is shown in Table 11 below.

Table 11. Estimated Total Cost for Alternative 5

		Total Cost Estimate (2023 million USD w/ allowance)
Alternative 5	low	267.5
	mid	**382.2**
	high	573.3

RELATIVE RANKINGS:

- Construction Cost: High (Rank: 5th)
- O&M Cost Consideration: High (Rank: 5th)
- Outage Duration: High (Rank: 5th)
- Expected Reliability: Medium (Rank: 3rd)
- Risks: High (Rank: 6th)
- Best Technical Solution: High (Rank: 2nd)

- Amount of Integration Work: High (Rank: 5th)
- Expected Benefit: High (Rank: 2nd)

3.6 Alternative 6: Addition of New Unit 4

Operating Envelope: (45 MW to 204 MW)

Discussion:

The Unit 4 alternative for Helms would be an option to install a new reversible pump-turbine with the intent to increase overall plant capacity by a target of 150 to 180 MW. Preliminary selection for the new unit 4 pump-turbine indicates a maximum capacity of approximately 204 MW, for a unit sized to achieve 150 MW generator output at minimum head. This turbine could be a single-speed or a variable speed pump-turbine. This alternative would be the most expensive alternative in that extensive civil works (excavation, tunneling, and concrete work) would need to be completed to install the 4th unit. Integration of the fourth unit, sized at a smaller power output would have advantages such as additional load following flexibility, optimization for low load turbine generation power output, and increased total spinning reserve capacity.

Limits:

- Licensing and internal capability for project development and management.
- Environmental assessment and social economic approvals.

Merits:

- Asset management: A new pump-turbine unit can enhance the asset value and life cycle of the power plant by providing partial redundancy and backup for the existing units. A new unit can also extend the service life and reduce the wear and tear of the existing units by taking on operations for low load power output. It could also theoretically reduce the number of start-stop cycles on the other units for the lower power output unit calls. A new unit can also increase the revenue and profitability of the power plant by increasing the generation capacity and availability.
- Hydraulic efficiencies: A new pump-turbine unit can improve the performance and flexibility of the power plant overall if the scheme is designed in a way that water resource use is the focus for the design basis.
- Diversified generate mode power dispatch options, with the ability to potentially provide loads in the 40 to 50 MW range depending on manufacturer design basis.

Demerits:

- Significant incremental high upfront capital investment cost, including design and construction costs for modified conveyances and hydraulics and cavern design.
- Permitting and licensing requirements and extended development/execution period relative to present FERC margins for the existing unit uprate options.
- Alternative would require a full plant outage to incorporate a fourth unit, and associated costs of lost generation.

Scope of Work:

- General
  - Studies for the new unit location, required civil works, grid requirements and plant hydraulic analysis including transient studies with a fourth unit will need to be performed, as well as studies to select the best sizing and ratings of the new pump-generate equipment.
  - Major civil excavations and construction are required for the underground penstock and tailrace conveyance, machine hall, transformer gallery, and surge chamber. The adding of a fourth unit would be the largest upfront capital costs option. Essentially the excavation and placement of an entire new unit and water passageway, as well as supporting galleries and cable shafts / tunnels would be needed for this option.
- Pump-Turbine
  - The scope of work for the existing units (U1, U2 and U3) is identical to Alternative 1, but with an additional Unit 4 pump-turbine of reduced capacity installed at a similar unit centerline setting as the existing units.
- Motor-Generator
  - The scope of work for the existing units (U1, U2 and U3) is identical to the Alternative 1.
  - Complete new generator considering electrical optimizations to complement the expected generation with the existing units.
- General
  - Civil-Structural Works
    - Extend powerhouse rock chamber (rock drilling method and expansive demolition grout method)
    - Extend transformer rock chamber (rock drilling method and expansive demolition grout method)
    - Extend existing powerhouse crane rails (new rock anchors, new concrete and new steel rails)
    - Existing concrete demolition works
    - Concrete works for new unit
    - Structural steel works for new unit
  - Water Conveyance System
    - The existing water conveyance system would need to be extended on both the high pressure as well as low pressure sides by adding an additional bifurcation and associated piping to connect the new Unit 4

        - Build new pressurized steel lined penstock tunnel
        - Build new steel lined draft tube extension
    - TSV
        - A new Unit 4 TSV would be required for the addition of a new unit.
    - Draft Tube Gates
        - A new Unit 4 DTG would be required for the addition of a new unit.
    - Station Switchyard System
        - Scope of work is identical to Alternative 1 scope of work except for adding HV cables and switchyard equipment for the new unit.
    - BoP Mechanical
        - New BoP systems would be required for the new unit, including cooling water for the transformer and pump-turbine/motor-generator, a fire suppression system, underground air exchange, HVAC, and drainage systems. New switchyard BoP systems would also be needed as well.
    - BoP Electrical
        - Scope of work is identical to Alternative 1 scope of work except for the following:
            - A new starting motor transformer is needed for new unit.
            - A new 13.8 kV station service bus is needed for new unit.
            - A new 13.8 kV station service switchgear is needed for new unit.
            - A new station service transformer will be needed for new unit.
            - A new load center is needed for new unit.
            - The existing 125VDC station power system will be refurbished or replaced to include loads for new unit.
            - The existing UPS will be refurbished or replaced to include loads for new unit.
            - A new protection and unit control system is needed for the new unit and main bank transformer.
- Main Bank Transformer
    - Scope of work is the same as Alternative 1, except that a new main bank transformer is also needed for the new unit.
- Disconnect Switches, Iso Phase Bus, and Exciter Bus
    - Scope of work is identical to Alternative 1 scope of work except for the following:

- A new isolated phase bus duct is needed for new unit.
- A new high resistance neutral grounding equipment is needed for new unit.
- A new excitation system PPT and switchgear is needed for new unit.
- A new starting motor is needed for new unit.
- A new starting bus is needed for new unit.
- A new stating motor selector switch is needed for new unit.
- A new phase reversing switch is needed for new unit. The phase reversal switch may not be needed if a motor-generator circuit breaker is installed for new unit as the breaker could provide the reversing of phases during generator and pump mode operations.
- A new motor-generator circuit breaker is needed for new unit.

Costs:

See section 5.0 for a detailed breakdown of the OPCC. The estimated total cost for alternative 6 is shown in Table 12 below.

Table 12. Estimated Total Cost for Alternative 6

		Total Cost Estimate (2023 million USD w/ allowance)
Alternative 6	low	329.9
	mid	**471.3**
	high	707.0

RELATIVE RANKINGS:

- Construction Cost: High (Rank: 6th)
- O&M Cost Consideration: High (Rank: 6th)
- Outage Duration: High (Rank: 6th)
- Expected Reliability: Medium (Rank: 4th)
- Risks: Medium (Rank: 3rd)
- Best Technical Solution: High (Rank: 1st)
- Amount of Integration Work: High (Rank: 6th)
- Expected Benefit: High (Rank: 1st)

4.0 Opinion of Probable Construction Cost

This task consisted in estimating prices for the main scope items identified for each of the alternatives analyzed in this alternatives analysis report. As noted in Table 6, each component was assigned one or more of the following alternatives: refurbish, replace with new (new equipment), or reuse (in the case of equipment that was not recommended for major rehabilitation or replacement).

The OPCC estimates are considered Class 5 estimates as defined by AACE International in Recommended Practice 69R-12 ("Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industry"); Class 5 estimates are typically used for strategic business planning purposes, such as evaluation of alternatives, project screening, evaluation of resource needs and high-level budgeting, and long-range capital planning and is typically based on a design level of 2% or less. The accuracy range is typically between -20% to -50% in the low end, and +30% to +100% in the high end.

The OPCC is considered a 'snapshot in time' estimate. Portions of the cost estimate are based on historical data (i.e. equipment supply costs), which does include some more recent data points from the past couple of years (including some recent, post COVID period data). Of particular note are the general conditions that are prevalent now, as the economy comes out of the pandemic constraints, and the international supply chain challenges. Also notable are the uncertainties of the infrastructure investments that will occur as a result of recent legislation and pricing from climate change initiatives. These and many other factors contribute to a particularly volatile background to construction cost estimating at the time of writing.

Table 13. Opinion of Probable Construction Costs (Class 5)

Alternative	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5	Alt. 6
Lower Operating Limit (MW)	**83**	**73**	**83**	**<83**	**190**	**U4: 45 U1-3: 83**
Upper Operating Limit (MW)	**404**	**404**	**450 - 460**	**450 - 460**	**460**	**U4: 204 U1-3: 404**
Price Characteristics (2023, million USD)						
Pump-Turbine	35.40	35.40	47.57	47.57	48.37	46.75
Motor-Generator	42.50	42.50	70.25	70.25	100.26	57.61
Civil-Structural Works	0.23	0.23	2.48	2.48	5.24	55.00
TSV & Draft Tube Gates	0.00	0.00	0.00	0.00	0.00	15.90
Station Switchyard System	3.32	3.32	22.86	22.86	22.86	10.63

Alternative	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5	Alt. 6
BoP Mechanical	0.00	0.00	1.50	1.50	1.75	10.07
BoP Electrical	5.90	5.90	5.96	5.96	6.53	12.62
Main Bank Transformer	33.00	33.00	33.00	33.00	33.00	36.80
Disconnect Switches, Iso Phase Bus, and Exciter Bus	6.03	6.03	10.06	10.06	19.40	10.79
Subtotal	**126.37**	**126.37**	**193.67**	**193.67**	**237.39**	**256.17**
Installation and Testing Alt 1 - 5: 15% Alt 6 : 20%	18.96	18.96	29.05	29.05	35.61	38.43
Direct Construction Cost	**145.33**	**145.33**	**222.72**	**222.72**	**273.00**	**294.59**
Owner's Engineering Allowance Alt 1 - 5: 10% Alt 6 : 15%	14.53	14.53	22.27	22.27	27.30	44.19
PG&E's Internal Cost Alt 1 - 5: 10% Alt 6 : 15%	14.53	14.53	22.27	22.27	27.30	44.19
Scope Allowance & Contingency 20%	29.07	29.07	44.54	44.54	54.60	88.38
Total OPCC	**203.46**	**203.46**	**311.81**	**311.81**	**382.20**	**471.35**
Cost Adjustment of -30% for CBA Sensitivity Analysis	142.42	142.42	218.27	218.27	267.54	329.94
Cost Adjustment of +50% for CBA Sensitivity Analysis	305.18	305.18	467.72	467.72	573.31	707.02

The preliminary OPCC is provided in 2023 USD and includes sufficient detail to allow comparison of various alternatives. Additional details may be accounted for during more advanced planning phases with higher level of project definition to incorporate revised scope and contracting strategy decisions. Escalation to expected contract(s) award or construction midpoint is not included.

The following assumptions were made in preparation of the OPCC:

It is assumed an experienced OEM would be contracted for the supply, refurbishment, and disassembly/ installation of the pump-turbine / motor-generator and auxiliary equipment.

While it is assumed MBOP components can be reused as-is for Alternatives 1 and 2, an allowance of 0.5 MM per unit is assumed for minor system rework such as routing and duty modifications with uprated units (Alternatives 3 to 5). Any other cleaning, inspection, replacement efforts for the MBOP systems are assumed to be covered under separate plant maintenance efforts. The extent of integration for a new Unit 4 into the Mechanical Balance of Plant (MBoP) systems is extremely difficult to estimate at this stage – an allowance value of value of ~8.5MM was included for this item, consistent with parametric price estimates for essential mechanical system for a new unit of comparable size.

Please note that while Alternatives 1 through 5 could be staged such that only one unit is in extended outage at a time, Alternative 6 would require a full plant outage to incorporate the 4th unit water passages. This additional cost of lost generation (not included in the scope of the OPCC) is expected to be quite significant to the overall cost of implementing the alternative.

Percentages of the rolled-up Direct Construction Cost were used to estimate PG&E and Owner's Engineer Services, as well as for scope contingency, in line with previous experience in similar refurbishment works.

Owner's engineer services may include the following services over the course of the project: condition assessment, project scoping, preparation of bid documents, bid evaluation, support during contract negotiations, vendor submittal/RFI review, and on-site oversight during commissioning and performance testing. An allowance equal to 10% of the OPCC subtotal was added to the base cost estimate to account for these services during procurement, fabrication, and construction. A 15% markup for Alternative 6 to cover additional studies and design efforts for incorporation of the 4th unit.

Similarly, PG&E internal costs (i.e., project management, internal engineering, plant support) have been assumed as a 10% markup to the subtotal. Markup was increased to 15% for Alternative 6, again for Unit 4 additional efforts.

Finally, a 20% scope contingency has been applied to each alternative considering only high level desktop engineering studies have been completed at this time, and to account for unforeseen conditions. As with any work that considers rehabilitation or reuse of components, there will be issues that arise throughout the course of the project, and thus an allowance has been added to account for unforeseen conditions. Given the significant uncertainty for powerhouse excavation scope and how best to incorporate an additional unit, a 30% contingency has been added to Alternative 6.

Further discussions with plant personnel, and a thorough condition assessment of the units will be critical in establishing the final project scope; however, as the project progresses, additional work related to unforeseen conditions is to be expected or mitigated. For pump-turbine / motor-generator components identified in the engineering assessment that could be reused, they will be disassembled, cleaned, inspected dimensionally and via non-destructive examination, and evaluated for reuse. It is not uncommon to discover issues such as cracks, out-of-tolerance dimensions, excessive pitting, etc. during unit rehabilitation, which cannot be discovered until after the unit is disassembled. Resolution of these issues constitutes out-of-scope work for the contractor. Procurement of new parts mitigates such risk, but at this time, some level of reuse for the various pump-turbine / motor-generator components is expected for all alternatives.

At this level of the project assessments and estimates, the OPCC is essentially the same for alternatives 1 and 2, as well as for 3 and 4 – as the only difference is operating range of the pump-turbine and is a function of the hydraulic design. Stretching the operating range as far as possible may have future effects as it relates to O&M costs and additional wear and tear on the machine. OPCC for Alternative 6 comes in the highest of the alternatives, and should end up with an even greater cost difference to the other alternatives once the relative loss of revenue due to a complete plant shutdown is considered.

5.0 Conclusion

The Alternatives Analysis indicates that Alternative 3 is the preferred alternative among the six alternatives reviewed by Stantec. Although other alternatives scored higher in some individual categories of the evaluation, Alternative 3 scored better in the most weighted categories including technical solution, reliability, and cost. While Alternatives 5 & 6 provide more operational flexibility and increased capacity respectively, the construction cost, outage duration, and amount of integration work necessary for these two alternatives are significantly higher than Alternative 3. Alternatives 5 & 6 also require significant modifications to the existing structure.

Alternative 1 is a valid second option to the preferred alternative 3 due to its proven track record and simplicity of its scope of work. However, alternative 1 fails to meet the uprate objective of this project. Most existing equipment is at the end of its original design life and a lifetime extension project for Helms is imminent. Since this lifetime extension project will require refurbishment and replacement of major components of the plant, as described in the scope of work for alternative 1, uprating these components for alternative 3 makes sense. The incremental cost increase for the uprate is expected to be outweighed by the expected benefits coming from the increased unit capacity.

Stantec recommends that PG&E use the cost and operational information from the alternatives and review the cost vs. benefit for the viable alternatives and determine the overall net benefits. Stantec has only reviewed the technical benefits due to the lack of information on power pricing and cost of ancillary services, that PG&E, due to confidentiality reasons, could not provide.

Stantec has developed an opinion of probable construction cost for each alternative based on the scope of work detailed in each alternative. The costs have been developed based on historical data from similar equipment and parametric pricing curves. Future pricing is very uncertain due to the prevailing volatility in market conditions. We recommend that the cost estimates be used for comparison of the alternatives and a detailed project cost estimate be developed after selecting the preferred alternative and refining the scope of the project.

6.0 References

Stantec Consulting Services Inc. September 2023. *Engineering Assessments Report.*

[redacted] "Helm Creek Mechanical History 1984-2018". May 12, 2020.

Appendix 1 – Potential Additional Alternative – “Alternative 7”

Alternative 7: Subsequent to development and agreement that the Alternatives Analysis would include the six alternatives detailed above, PG&E identified a seventh alternative that PG&E believes may be beneficial and worthy of consideration. This alternative is outside the scope of this Alternatives Analysis report, but is described here and documented for potential future consideration. This alternative consists of the addition of new variable speed Units 4 and 5 along with addition of synchronous condenser capability for the existing units 1, 2, and 3. This alternative also includes removal of the existing 13.8kV system including starting motor by means of additional 18kV Generator Breakers to be located in the area of the Phase Reversal Switches and Static Frequency Converter(s) to be located in the area of the existing Liquid Rheostats. This is basically an adder to Uprate option 3 with the addition of adding synchronous condense mode for the turbines, which would be designed for the reduction in head due to two additional new units at a size of approximately 100MW each.

Though costly, two new smaller variable speed converter fed units could allow capturing all the available power from the water conveyance tunnel. The Variable Speed converter fed units could be synchronous machines that utilize the limit of variable speed technology. According to the B&V study, there is potentially approximately 400 MW additional available power capacity available in the hydraulic capacity of the existing water conveyance tunnel. This plan could provide maximum flexibility for load in both pump and generate and along with the existing unit's 1-3 new synchronous condense capability, could effectively sell all at spinning reserve. It would add 350-400 additional Megawatts, allow for improved optimization of the sizing of the new runners for the existing units, and use all the existing hydraulic power capacity from the tunnel. It also softens the blow for annual, extended planned, and forced outages of single units. Rough estimates appear to show this could add a benefit at about 2.2 Million dollars per Megawatt of new storage. It could be constructed in phases with little multi unit outage impact. Coordination with the new draft tube gate is important as design feature of the new gates could include the ability to close draft tube gate and TSV, draining the water out of the runner area, to synchronous condense.

The existing crane, access tunnel and other powerhouse equipment could support new units if located in the bypass tunnel area where the underground rock is mapped more heavily than nearly anywhere on (in) earth. The new units could have a fairly small cable or bus shaft drilled rather than driven to the surface.

Removal of the 13.8kV starting motor system greatly simplifies the project with regard to component overhaul. For example: Existing method to start the pump is to have a different unit available to source the starting motor, energize the 13.8kV bus from a large aux transformer, utilizing medium voltage switchgear, start the motor, using the secondary 4.2kV bus to regulate the speed via a liquid rheostat once the 1R switch is closed for the unit in start. All these components can be eliminated by the following: 1. Add 18kV parallel or back-to-back breakers at the reversing switch area. One breaker for Gen mode and one breaker for pump mode. This eliminates the reversing switch replacement and adds benefit by: additional protection particularly the GSU transformer, brings the heavy maintenance of the 230kV breakers in the switchyard into the powerhouse where year-round access is available and a crane, along with easy monitoring by operations. The pump breaker would get the most use and in turn need more service, but the gen breaker would last potentially 20,000 cycles before major overhaul. The isophase bus is necessary to be replaced anyway for the uprate so the cost of modification to it is small. Modern Generator breakers for PS plants include an SFC starting switch which allows the unit being started (its own source since the GSU is already energized) to start itself by activating the SFC in pump start. This eliminates the need for the entire 13.8kV system. The 13.8kV bus, Aux transformers 11, 12, 13, phase reversal switch, medium voltage starting motor switchgear, both liquid rheostats, the problematic 1R rotor bus switches, and the starting motors all go away. This allows a clean upper generator design for a new bearing without need for starting motor. It would require replacing the starting motor rotor bus with a bus for the SFC. Overall, extremely clean solution and many components removed for few components re-installed. Other benefits of adding a generator breaker include consolidating the PTs and CTs into the breaker space and reducing the start/stop cycles on the GSU transformers.