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Analysis of Power Delivery to the WTP to Achieve a Minimum of 70MW (76.4MVA)

R. S. Ziegenbein
September 13, 2010
Richland, WA 99352
U.S. Department of Energy Contract DE-AC27-08RV14800

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Abstract: Results of report: BNI WTP Load Flow Analysis was found to be reasonable; BNI Fifth Feeder Study was found to be reasonable; Power factor correction system is not cost effective to implement and a harmonics analysis must be performed prior to implementation of a power factor correction system; Upgrading A6 Substation transformers to 100MVA and switchgear and bus ducts to 4,000A will provide 70MW (76.4MVA) to the WTP; Hanford 230KV has sufficient capacity to feed the WTP and projected loads; and follow transformer manufacturers literature for operating capacity during loss of fan cooling..

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Analysis of Power Delivery to the WTP to Achieve a Minimum of 70MW (76.4MVA)

September 2010

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Washington River Protection Solutions, LLC

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LIST OF TERMS

Terms

MW (MVA). A real power megawatt (MW) figure immediately followed by an apparent power megavolt ampere (MVA) figure is used throughout this report to indicate the power factor of a particular electrical load or demand. Example: a real power of 70MW at a 91.6% lagging power factor gives an apparent power of 76.4MVA, hence 70MW (76.4MVA) This convention is used throughout this WRPS report to aid in aligning discussions of real power, power factor, apparent power, electrical demand and the rated capacity of the transformers which are given in units of MVA.

Rough order of magnitude cost estimate. A rough order of magnitude (ROM) cost estimate has an accuracy range of -30% to +50% and includes the estimated total installed cost (TIC) composed of Engineering, Procurement, Construction and Commissioning (EPCC) estimates. The cost estimates contained within the URS Study are documented with the study and are based on URS Project Execution Procedure (PEP) 301, Estimating Form 301-02(s) and General Estimating Guidelines for Order of Magnitude Estimates.

Rough order of magnitude schedule. A ROM schedule has an accuracy range of -30% to +50%, is based in engineering judgment and includes only EPCC activities. A rough order of magnitude schedule does not include the Department of Energy (DOE) budgetary cycles required to fund and authorize an EPCC project. The ROM schedule begins upon DOE authorization of an EPCC contract.

Transformer capacity ratings. The transformers mentioned within this WRPS report are triple rated forced-air fan cooled. The base stage is self cooled requiring no operations of fans. The second stage is forced-air fan cooled requiring the operation of one set of fans. The third stage is forced-air fan cooled requiring the operation of both sets of fans. The capacity rating of the 37/50/62MVA transformers is a base self cooled rating of 37MVA with two additional forced-air fan cooled stages of 50MVA and 62MVA. The capacity rating of the 60/80/100MVA transformers is a base self cooled rating of 60MVA with two additional forced-air fan cooled stages of 60MVA and 100MVA. Throughout this report transformer capacity rating may show only the third stage forced-air fan cooled maximum rating, i.e. 62MVA or 100MVA.

URS Study. URS Corporation study, Analysis of Power Delivery to the WTP to Achieve a Minimum of 70MW (76.4MVA), Project Name: Analysis of Power Delivery to WTP, Project Number: 29906, URS Study Number: 17-05-110-001, Revision Number: 0, will be referred to as the URS Study throughout this WRPS report.

Worst case scenario. A worst case scenario is defined as the entire WTP load being carried on a single A6 Substation transformer. This equates to a one out of two transformer arrangement. Several options were considered utilizing three or four transformers serving the WTP. These equate to two out of three or two out of four transformer arrangements. For purposes of the URS Study, these alternate arrangements were assumed to meet the intent of a worst case scenario. It must be noted that an option meets the criteria of providing a minimum of 70MW (76.4MVA) capacity to the WTP under a worst case scenario only after construction and commissioning activities have been completed.

Abbreviations and Acronyms

BPA	Bonneville Power Administration
BNI	Bechtel National Inc.
CD	compact disc
DOE	Department of Energy
EPCC	Engineering, Procurement, Construction and Commissioning
ICD	Interface Control Document
IEEE	Institute of Electrical and Electronics Engineers
MSA	Mission Support Alliance
ORP	Department of Energy Office of River Protection
PFCS	power factor correction system
RL	Department of Energy Richland Office
ROM	rough order of magnitude
TF	tank farm
TIC	estimated total installed cost
WRPS	Washington River Protection Solutions
WTP	Waste Treatment and Immobilization Plant

Units

A	ampere
KV	kilovolt
MVA	megavolt ampere
MW	megawatt

EXECUTIVE SUMMARY

Washington River Protection Solutions (WRPS) was directed by the Department of Energy Office of River Protection (ORP) to perform analyses and determine viable options for increasing power delivery up to at least 70 megawatts (MW), under a worst case scenario, to the Waste Treatment and Immobilization Plant (WTP). The scope of the analysis efforts were further refined in letters between WRPS and ORP. URS Corporation was tasked by WRPS to prepare a study to address the scope of work bounded by the letters.

It must be recognized that this WRPS report and the URS Study are not intended to be utilized as design documents. Actions based on recommendations in this WRPS report and the URS Study will require detailed design analyses. A summary of the URS Study recommended options, conclusions and recommendations follows.

RECOMMENDED POWER DELIVERY OPTIONS

The URS Study presents ten power delivery options evaluated in accordance with the approved scope of work. Nine options address delivering a minimum of 70MW (76.4MVA) to the WTP under a worst case scenario without consideration of forecasted tank farm loads, baseline future projects loads and future initiative projects loads. The tenth option was developed to address a wider scope of work to deliver power to a 70MW (76.4MVA) WTP load in combination with forecasted tank farm loads, baseline future projects loads and future initiative projects loads.

Option 1, A6 Substation Electrical Equipment Upgrade, is the recommended option to deliver 70MW (76.4MVA) to the WTP under a worst case scenario without consideration of forecasted tank farm loads, baseline future projects loads and future initiative projects loads. This option consists of upgrading the two transformers to 100MVA and upgrading the switchgear and bus ducts to 4,000 ampere (A). Option 1 is recommended for the following reasons:

- Meets the functionality requirement of providing a minimum of 70MW (76.4MVA) of power under a worst case scenario to the WTP
- Provides up to 95.6MVA of capacity, limited by the 4,000A switchgear and bus ducts
- Maintains the same level of reliability as the current A6 Substation configuration
- Second lowest rough order of magnitude (ROM) estimated total installed cost (TIC) of $12.3 million (M) of the options that meet the 70MW (76.4MVA) requirement
- Shortest implementation time of 2 years.

Option 10, Hanford 230 kilovolt (KV) A6 Substation Expansion, is the overall recommended option to provide power to the WTP in combination with forecasted tank farm loads, baseline future projects loads and future initiative projects loads. Option 10 supplements the current A6 Substation by adding: two 100MVA transformers, two 4,000A bus ducts, two 4,000A switchgear and one switchgear building. Option 10 is recommended for the following reasons:

- Provides the best long term value to ORP and Department of Energy Richland Office (RL) through the efficient use of the A6 Substation and A8 Substation existing electrical equipment.
- Addresses the projected load increases for the WTP as well as the 200 Area electrical load increases supporting the WTP.
- Least likely to impact the WTP project schedule. Existing duct banks feeding the WTP consist of sets of 6” schedule 40 PVC conduit. Two of these existing duct banks must be revised to accept two new Option 10 circuit duct bank/conduit systems that will feed the WTP. These two duct bank/conduit revisions must be completed early in the implementation of Option 10 to minimize operational impacts to achieve the full benefit of low impact to the WTP project schedule.
- The WTP can continue to utilize the current A6 Substation (62MVA), through construction, commissioning, startup and several years of operation on the calculated 53MW (58MVA) WTP electrical load demand.
- Permits a delay in most implementation activities which will enable the design of the waste treatment processes to be refined.
- Facilitates a more efficient sizing of the A6 Substation expansion equipment thereby reducing lifecycle operations costs.

The Hanford 230KV electrical system and the A6 Substation 230KV feeder cables have sufficient capacity to carry the loads imposed by Options 1 and 10.

RESULTS AND RECOMMENDATIONS

HANFORD 230KV ELECTRICAL UTILITY SYSTEM CAPACITY

Results - The Hanford 230KV system capacity is approximately 268MVA, including the A6 Substation feeder lines. The total projected Hanford 230KV system load is approximately 180MVA or 67% of the Hanford 230KV system capacity. The projected Hanford 230KV system load is composed of: 70MW (76.4MVA) projected WTP electrical loads, 78MVA for the Hanford 230KV Baseline Case projected loads, and 22MW for the current Hanford 230KV loads (A7 and A8 Substations).

Recommendation - It can be concluded that no modifications to the 230KV system will be required to deliver 180MVA of projected loading, pending further evaluation and concurrence by Bonneville Power Administration (BPA) which is being pursued by RL.

WTP LOAD FLOW ANALYSIS

Results - The WTP Load Flow Analysis performed by Bechtel National Inc. (BNI), utilized commercially available software (ETAP) with a methodology that follows industry standards. The demand factors utilized in the WTP Load Flow Analysis are within the range of industry standards and the assumptions made show reasonable engineering judgment.

Recommendations - Recommendations are made to revise the Interface Control Document for Electricity (ICD-11) to state: maximum average operational power, operational growth margin, real power and apparent power.

FIFTH FEEDER STUDY

Results - The review of the BNI Fifth Feeder Study finds the document to be reasonable in its methods, assumptions, and conclusions based on the available information presented for review.

Recommendation - The Fifth Feeder is not recommended as a permanent power source for the WTP.

POWER FACTOR CORRECTION SYSTEM

Results - The Hanford 230KV electrical system operates at a 93% leading power factor and will remain leading after the connection of the calculated WTP 53MW load at 91.6% lagging power factor to the Hanford system. Calculations show that by changing the power factor from 91.6% lagging to 97% lagging an additional 3MW of demand can be achieved on a 62MVA transformer.

Recommendations - The installation of a power factor correction system is not recommended on an economic basis because BPA currently does not assess a power factor penalty against the Hanford 230KV electrical utility system, therefore there is no economic benefit to install a power factor correction system. In addition, the design and installation of a power factor correction system is not recommended until harmonic and wave form distortion analyses have been completed.

LOSS OF TRANSFORMER FAN COOLING

Results - The 62MVA and 100MVA transformers are each capable of carrying the self-cooled and forced-air fan cooled ratings under rated ambient temperature and atmospheric conditions for the design lives of the transformers.

Recommendations - If a transformer is to be operated outside of the transformer manufacturer's recommended range of operation, the transformer manufacturer should be consulted and the limitations of Institute of Electrical and Electronics Engineers (IEEE) C57.91, IEEE Guide for Loading Mineral-Oil-Immersed Transformers, Appendix H should be followed.

Recommendations are made to procure transformers with: fan motor watt or current sensing equipment with remote monitoring capability, air flow sensors with remote monitoring capability and spare fans, fan motors, temperature sensors and wiring harnesses. Procedures should also be proactively developed to address the loss of fan cooling system operation.

1.0 INTRODUCTION

Washington River Protection Solutions (WRPS) was directed by the Department of Energy Office of River Protection (ORP) in a March 12, 2010 letter to perform analyses and determine viable options for increasing power delivery up to at least 70 megawatts (MW), under a worst case scenario, to the Waste Treatment and Immobilization Plant (WTP). The scope of the analyses and work were further defined in a April 22, 2010 letter from WRPS to ORP. URS Corporation was tasked by WRPS to prepare a study in keeping with the scope of work bounded by the above letters. Input to the analysis efforts was solicited from Department of Energy Richland Office (RL), Mission Support Alliance (MSA) and the Central Design Authority and Standards group of WRPS. The scope of work was further defined by subsequent correspondence between WRPS and ORP during the conduct of the analyses. The key recommended options, conclusions and recommendations from the URS Study are presented in the Executive Summary.

2.0 SCOPE OF WORK

The scope of work is organized into six general categories that address recommending power delivery options and addressing issues related to providing 70MW (76.4 megavolt ampere (MVA)) of power to the WTP, determining the capacity of the Hanford 230 kilovolt (KV) electrical system, reviewing the WTP load flow analysis, reviewing the fifth feeder study to the WTP, determining benefits of adding power factor correction capacitors to the WTP/Hanford 230KV electrical system and reviewing issues related to the loss of fan cooling in power supply transformers to the WTP. The following sections provide a description of the scope of work with the resultant recommended options, conclusions and recommendations documented in the URS Study.

2.1 VIABLE OPTIONS TO DELIVER A MINIMUM OF 70MW (76.4MVA) TO THE WTP UNDER A WORST CASE SCENARIO

Scope of Work

The following describes the scope of work derived from the WRPS and ORP correspondence:

- Analyze and determine viable options for increasing power delivery beyond the existing 62 MVA single transformer capacity limitation up to at least 70MW (76.4MVA) capacity to the WTP, under a worst case scenario.
- Compare WTP power needs to existing system capabilities.
- Develop alternative methods, including A6 Substation expansion and revised operational scenarios.
- Identify and list possible solutions.

- The inherent vulnerabilities, advantages, disadvantages and limitations of each option shall be documented.
- Weigh options using a cost-benefit analysis.
- Provide rough order of magnitude (ROM) cost estimates and schedules to implement the recommended options.
- Confidence in the cost estimates shall be presented either by a cost range or confidence level.
- The basis of the cost estimates shall be documented.
- Determine the most cost effective approach for increasing power delivery to the WTP.
- Recommend options to deliver at least 70MW (76.4MVA) of power to the WTP.
- Recommend a single option to deliver at least 70MW (76.4MVA) power to WTP under a worst case scenario.
- Verify, or identify impacts, that the Hanford 230KV electrical system and existing A6 Substation 230KV feeders have sufficient capacity to carry the 70MW (76.4MVA) WTP load imposed by the recommended option.

Evaluated Power Delivery Options

The URS Study presents ten power delivery options evaluated in accordance with the approved scope of work. Nine options address delivering a minimum of 70MW (76.4MVA) to the WTP under a worst case scenario without consideration of forecasted tank farm loads, baseline future projects loads and future initiative projects loads. Option 10, was developed to address a wider scope of work to deliver power to a 70MW (76.4MVA) WTP load in combination with forecasted tank farm loads, baseline future projects loads and future initiative projects loads. Option 10 is presented in the following Hanford 230KV Electrical Utility System section.

Recommended Power Delivery Option

Option 1, A6 Substation Electrical Equipment Upgrade, is the recommended option to deliver 70MW (76.4MVA) to the WTP under a worst case scenario without consideration of forecasted tank farm loads, baseline future projects loads and future initiative projects loads. This option consists of upgrading the two transformers to 100MVA and upgrading the switchgear and bus ducts to 4,000 ampere (A). Option 1 is recommended for the following reasons:

- Meets the functionality requirement of providing a minimum of 70MW (76.4MVA) of power under a worst case scenario to the WTP
- Provides up to 95.6MVA of capacity, limited by the 4,000A switchgear and bus ducts
- Maintains the same level of reliability as the current A6 Substation configuration
- Second lowest rough order of magnitude (ROM) estimated total installed cost (TIC) of $12.3 million (M) of the options that meet the 70MW (76.4MVA) requirement
- Shortest implementation time of 2 years.

The Hanford 230KV electrical system has sufficient capacity to carry the loads imposed by Option 1. The A6 Substation 230KV feeder cables also have sufficient capacity to carry the loads imposed by this option.

Noteworthy Power Delivery Option

Although Option 1 is recommended, Option 6 provides some interesting features worthy of discussion. Option 6, Warehoused Spare, consists of purchasing and warehousing one 62MVA transformer. This option does not meet the requirement to deliver a minimum of 70MW (76.4MVA) of electrical power under worst case scenario, but does warrant special attention for the following reasons:

- Lowest option ROM TIC of $1.5M, excluding warehouse and storage costs
- Does not change the reliability of the existing design
- Minimizes the reduced operational period of the WTP during transformer replacement to approximately a month or less, assuming work processes and work permits are prepared in advance. Given the year turnaround time on the procurement of this type of transformer, this is a substantial improvement in transformer replacement time.
- Preserves the existing WTP commissioning, operations and contract agreements.

A complete listing of the ten power delivery options analyzed in the URS Study follows. Implementation of any of these options will require some degree of revision to the WTP authorization basis documents. No cost or schedule considerations were made to address revising the authorization basis documents. The ROM construction schedules do not address the duration and types of outages to the WTP inherent with the implementation of each option. Detailed outage information could be a valuable option selection criteria to be used during follow on design efforts, but is outside the conceptual scope of work for the URS Study.

Table 1 Options reviewed to deliver a minimum of 70MW (76.4MVA) to the WTP.

Opt	Description	Functionality	Reliability	Cost/Schedule
1	"A6 Substation Electrical Equipment Upgrade" Upgrade transformers to 100MVA, Upgrade switchgear and bus ducts to 4,000A	Meets 70MW (76.4MVA) requirement	Dual redundant line-up	$12.3M / 2 Yr
2	Upgrade transformers to three winding 100MVA, Add two 3,000A switchgear and bus ducts, Add switchgear building	Meets 70MW (76.4MVA) requirement	Dual redundant line-up	$18.4M / 2 Yr Not considered cost viable, insufficient space in switchgear building
3	"Partial expansion of A6" Add two transformers 62MVA Upgrade switchgear to 4,000A, Add two 3,000A bus ducts, Add switchgear building	Meets 70MW (76.4MVA) requirement	Dual redundant line-up	Cost Not Estimated. Not considered cost viable, insufficient space in switchgear building
4	"62MVA expansion of A6" Add two transformers 62MVA, Add two 3,000A switchgear and bus ducts, Add switchgear building	Meets 70MW (76.4MVA) requirement	Dual redundant line-up	$17.5M / 2 Yr Not considered cost viable, insufficient space in switchgear building
5	"Swing bus" Add one transformer 62MVA, Add two 3,000A bus ducts, Add switchgear building	Meets 70MW (76.4MVA) requirement	Dual redundant line-up	$12.6M / 2 Yr Not considered cost viable, insufficient space in switchgear building
6	"Warehoused spare" Buy/warehouse one transformer 62MVA Allows timely replacement of transformer at minimum cost	Does NOT meet 70MW (76.4MVA) requirement	Dual redundant line-up	$1.5M /1 Yr Not considered viable unable to meet 70MW (76.4MVA) requirement
7	"Direct feed to WTP" Upgrade transformers to three winding 100MVA, Add two 3,000A bus ducts	Meets 70MW (76.4MVA) requirement	Dual redundant line-up	$10.5M /2 Yr
8	Remove the requirement of 100% electrical load operations while on one transformer	Does NOT meet 70MW (76.4MVA) requirement	Single redundant line-up	Not considered viable, ability to overload a single transformer as the result of automatic transfer switch operation
9	Concurrent implementation of fifth feeder and power factor correction system	Does NOT meet 70MW (76.4MVA) requirement	Dual redundant line-up	Not considered viable, unable to meet 70MW (76.4MVA) requirement
10	Hanford 230KV A6 Substation Expansion Supplement A6 Substation by adding: two transformers 100MVA, two 4,000A switchgear and bus ducts and one switchgear building	Meets 70MW (76.4MVA) requirement	Dual redundant line-up	$20.2M / 2 Yr Also addresses projected tank farm loads necessary to support the WTP

Notes:
Cost information is based on URS standard estimating rates and factors.
The basis of the cost estimates are documented within the URS Study.
Schedule information based on engineering judgment.
A = ampere
KV = kilovolt
M = million
MVA = megavolt ampere
MW = megawatt
WTP = Waste Treatment and Immobilization Plant
Yr = year

2.2 HANFORD 230KV ELECTRICAL UTILITY SYSTEM

Scope of Work

The following describes the scope of work derived from the WRPS and ORP correspondence:

- Perform a load flow analysis with forecasted tank farm loads, baseline future projects, future initiative projects, along with projected loads of the WTP and existing loads on the Hanford Site 230KV electrical system.
- The analysis shall verify the adequacy of the electrical capacity of the A8 Substation and its 13.8KV distribution system and Hanford 230KV system or identification of impacts to the Bonneville Power Administration (BPA).
- The original project scope required the power flow modeling of the 230KV systems to be performed utilizing SKM Power Tools for Windows software. Due to technical issues with the SKM data files, the scope of work was revised to allow the use of a manual computation to determine the capacity of the Hanford 230KV system.
- Determine the most beneficial and cost effective option for increasing the power capabilities to the WTP along with projected and existing loads of the tank farms and future projects.
- The inherent vulnerabilities, advantages, disadvantages and limitations of the option shall be documented.
- Provide ROM cost estimate and schedule to implement the recommended option.
- Confidence in the cost estimate shall be presented either by a cost range or confidence level.
- The basis of the cost estimate shall be documented.

Results

The available Hanford 230KV electrical utility system files were missing key electrical system component information which precluded the ability to perform the SKM Power Tools® for Windows® software analysis as described in WRPS and ORP tasking letters. As a compensatory means of answering the question "Does the Hanford 230KV system have sufficient capacity to support the 70MW (76.4MVA) WTP electrical loads, the Hanford Site projected loads, and current Hanford site loads?" a manual computation was completed in the URS Study. The Hanford 230KV system capacity is approximately 268MVA, including the A6 Substation feeder lines. No modifications to the 230KV system will be required to deliver 70MW (76.4MVA) to the WTP, pending further evaluation and concurrence by BPA which is being pursued by RL.

The projected Hanford 230KV system load is composed of:

- 70MW (76.4MVA) projected WTP electrical loads
- 78MVA for the Hanford 230KV Baseline Case projected loads
- 22MW for the current Hanford 230KV loads (A7 and A8 Substations).

The total projected Hanford 230KV system load is approximately 180MVA or 67% of the Hanford 230KV system capacity. No modifications to the 230KV system will be required to deliver 180MVA of projected loading, pending further evaluation and concurrence by BPA which is being pursued by RL.

Overall Recommended Power Delivery Option

Since nearly all of the Hanford 230KV electrical system projected loading is either directly or indirectly supporting the WTP, it is the recommendation of the URS Study that a solution addressing the entire projected Hanford 230KV system load growth be considered in place of the options that provide 70MW (76.4MVA) to the WTP without consideration of forecasted tank farm loads, baseline future projects loads and future initiative projects loads. The Hanford 230KV A6 Substation Expansion, Option 10, presented by RL, satisfactorily addresses the specific WTP present and future project electrical demands as well as the other 200 Area electrical loads that are presently being developed to support the WTP. Since Option 10 addresses the criteria outlined in the commission of the URS Study for the WTP electrical load demands as well as the projected electrical load demands of the Hanford Site 200 Area, Option 10 is the overall recommended option to provide electrical power to the WTP and the projected tank farm loads.

Option 10, Hanford 230KV A6 Substation Expansion, is the overall recommended option to provide power to the WTP in combination with forecasted tank farm loads, baseline future projects loads and future initiative projects loads. Option 10 supplements the current A6 Substation by adding: two 100MVA transformers, two 4,000A bus ducts, two 4,000A switchgear and one switchgear building. Option 10 is recommended for the following reasons:

- Provides the best long term value to ORP and Department of Energy Richland Office (RL) through the efficient use of the A6 Substation and A8 Substation existing electrical equipment.
- Addresses the projected load increases for the WTP as well as the 200 Area electrical load increases supporting the WTP.
- Least likely to impact the WTP project schedule. Existing duct banks feeding the WTP consist of sets of 6” schedule 40 PVC conduit. Two of these existing duct banks must be revised to accept two new Option 10 circuit duct bank/conduit systems that will feed the WTP. These two duct bank/conduit revisions must be completed early in the implementation of Option 10 to minimize operational impacts to achieve the full benefit of low impact to the WTP project schedule.
- Permits a delay in most implementation activities which will enable the design of the waste treatment processes to be refined.
- Facilitates a more efficient sizing of the A6 Substation expansion equipment thereby reducing lifecycle operations costs.

The Hanford 230KV electrical system has sufficient capacity to carry the loads imposed by Option 10. The A6 Substation 230KV feeder cables also have sufficient capacity to carry the loads imposed by this option.

2.3 WTP LOAD FLOW ANALYSIS

Scope of Work

The following describes the scope of work derived from the WRPS and ORP correspondence:

- Review and comment on Bechtel National Inc. (BNI) calculation Power System Load Flow Analysis, 24590-WTP-E1C-MVE-00004, Rev E.
- Review all items within: Section 2.3, Acceptance Criteria; Section 5.0, Methodology; and Section 6.0, Assumptions, with additional attention to; non-running standby loads determination; maximum power demand parameters; and power demands of continuous, intermittent, spare equipment/loads.
- Review design growth and potential changes in Section 8.1, Maximum Power Demand from DOE Substation for Operation of RPP-WTP Plant.
- Review data provided by BNI, including loads and required contingencies, redundancies and operability.

Results

The WTP Load Flow Analysis performed by BNI, utilized commercially available software (ETAP) with a methodology that follows industry standards. The demand factors utilized in the WTP Load Flow Analysis are within the range of industry standards and the assumptions made show reasonable engineering judgment.

Recommendations

Based on the review of the WTP Load Flow Analysis and on the current A6 Substation configuration, the URS Study recommends that the Interface Control Document for Electricity (ICD-11) be revised to reword the first paragraph of section 1.4.2 to modify the requirements for future margin, as follows: The maximum average operational power for the WTP is limited to 95.6MVA. For the purpose of design, a 30% operational growth margin shall be maintained to the point of construction complete for calculating the maximum average electrical power utilized for WTP facility operations. If electrical losses are not accounted for in the software utilized to calculate the maximum average operational electrical power requirements, an additional 5% electrical loss margin shall be included. The first sentence of this recommendation is based on Option 1 of the power delivery options studied for increasing system capacity to 70MW (76.4MVA). Should an option with a different maximum MVA be selected, a corresponding maximum MVA value should replace the 95.6MVA currently proposed. This recommendation is based on ORP's directions to BNI and on the industry standard, Institute of Electrical and Electronics Engineers (IEEE) 141, section 2.4.1.4 Forecasting and Planning, for projected load growth of an operational facility with a projected 40 year life span.

The 53MW (58MVA) electrical demand calculated in the WTP Load Flow Analysis and an IEEE 141 recommended 30% operational load growth results in 69MW (75MVA) of expected load through the life of the WTP. The current A6 Substation single transformer capacity of 62MVA is not expected to support the electrical needs over the 40 years of WTP operations.

The URS Study also recommends that ICD-11 specify electrical design or operational power limitations in terms of apparent power (MVA) or that power limitations be specified in terms of real power (MW) including a minimum power factor.

2.4 FIFTH FEEDER STUDY

Scope of Work

The following describes the scope of work derived from the WRPS and ORP correspondence:

- Comment on BNI study Feasibility Study to Use the Present 13.8KV Construction Power as the Fifth Feeder to WTP, 24590-WTP-ES-E-09-001, Rev 0.
- Review data provided by BNI, WRPS and MSA.

Results

The review of the BNI Fifth Feeder Study finds the document to be reasonable in its methods, assumptions, and conclusions based on the available information presented for review. However, converting the A8 Substation construction 7MW (7.6MVA) feeder for permanent use of WTP does not, by itself, meet the requirement to provide 70MW (76.4MVA) to the WTP.

Recommendation

However, it should be noted that in terms of a standby power source for designated WTP project loads, the BNI estimated $5.5M for BNI Fifth Feeder Study Option 4 is a cost effective alternative to achieve 7MW (7.6MVA) of electrical power versus the utilization of standby diesel generators. In other words, should additional loads be required to be supported, i.e., the HLW and LAW melters, the Fifth Feeder would be a cost effective method to do so. It should also be understood that implementing the Fifth Feeder as a standby power source, still does not protect the designated WTP loads from a loss of both of the BPA 230KV power sources, Midway Substation and Ashe Tap.

2.5 POWER FACTOR CORRECTION SYSTEM

Scope of Work

The following describes the scope of work derived from the WRPS and ORP correspondence:

- Evaluate the effect of the WTP load on the 230KV power factor and additional capacity achieved by increasing the power factor to 97%.
- The evaluation shall include a ROM cost estimate for increasing the power factor to 97% (e.g. adding capacitors).
- Evaluate if BPA will impose any penalty and the magnitude of the penalty if the power factor is less than 97%.
- Identify and recommend preferred power factor correction options and the inherent vulnerabilities with each option.

Results

Information received from MSA indicates that the Hanford 230KV electrical system operates at a 93% leading power factor and would remain leading even after the connection of a calculated WTP 53MW load at 91.6% lagging power factor to the Hanford system.

Calculations show that by changing the power factor from 91.6% lagging to 97% lagging an additional 3MW of demand can be achieved on an A6 Substation 62MVA transformer.

Recommendations

Power factor correction can be implemented with any of the power delivery options reviewed in the URS Study. However, it is not recommended to install a power factor correction system (PFCS) solely for the purposes of power factor correction. BPA currently does not assess a power factor penalty against the Hanford 230KV system. However, should BPA decide to assess the penalty based on BPA Transmission Services, 2010 Transmission and Ancillary Services Rate Schedule, the URS Study still does not recommend implementation of a PFCS solely for the purpose of power factor penalty avoidance.

Two concerns have been noted. A detailed harmonic analysis must be performed prior to implementation of a PFCS due to resonance that may occur between the PFCS and reactive WTP loads. IEEE 519 compliance is called out in both the WTP Basis of Design and the WTP Electrical Design Criteria. IEEE 519 recommends current distortion limits resulting from loads such as variable frequency drives and uninterruptible power supplies. Depending on the results of a harmonic analysis of the WTP loads, a filter bank PFCS may be required. The WTP project is scheduled to complete an electrical load harmonic analysis in December of 2010. Upon completion of the WTP electrical load harmonic analysis, should a filter bank be required to comply with the recommendations of IEEE 519, harmonics and power factor correction can be addressed simultaneously. The analysis necessary to perform this type of design is a specialty and is usually performed by the filter bank vendor on an operating plant, due to the risk of damage to both the filter bank and plant reactive loads.

The following table summarizes the power factor correction systems that were evaluated in the URS Study.

Table 2 Power factor correction systems reviewed for the WTP.

Description	Comments	Cost/Schedule
Passive or Fixed PFCS	Passive or Fixed system is not well suited for a single overall WTP PFCS	Not considered since this option is not suitable to WTP
Active/Automatic PFCS using Capacitor Banks	Detailed harmonics and distortion analyses must be performed prior to implementation	$1.3M / 18 months
Active/Automatic PFCS using Filter Banks	Detailed harmonics and distortion analyses must be performed prior to implementation	$2.1M / 18 months

M = million
PFCS = power factor correction system
WTP = Waste Treatment and Immobilization Plant

2.6 LOSS OF TRANSFORMER FAN COOLING

Scope of Work

The following describes the scope of work derived from the WRPS and ORP correspondence:

- Perform an evaluation on the capabilities of the existing A6 Substation 37/50/62MVA transformers to operate continuously at the second stage fan cooling rating of 62MVA and the effects of losing one or both stages of fan cooling.
- The evaluation will also cover similar situations on a 60/80/100MVA transformer.
- The review of applicable technical literature shall be documented.
- Recommendations shall be made on the capacities of the transformers with full and partial fan operations.
- Recommendations shall also be provided to mitigate the effects of loss of fan cooling.

Results

The nameplate rating of the existing A6 Substation transformers is 37/50/62MVA, which documents that the full load rating of the transformer is the base self cooled rating of 37MVA and two additional forced-air fan cooled stages of 50MVA and 62MVA. The 60/80/100MVA transformers referenced in Option 1 reflect a full load rating of a base self cooled rating of 60MVA and two additional forced-air fan cooled stages of 80MVA and 100MVA. These transformers are capable of carrying each rating for the design life of the transformer under rated ambient temperature and atmospheric conditions.

Recommendations

The forced-air fan cooled stage ratings require the fan systems to be fully functional. If the fan systems are not functioning, the transformer manufacturer's directions for transformer loading should be followed. If the transformer is to be operated outside of the transformer manufacturer's recommended range of operation, the transformer manufacturer should be consulted. In addition to the manufacturer's recommendation, IEEE C57.91, IEEE Guide for Loading Mineral-Oil-Immersed Transformers, Appendix H Section H.3 states the following:

- For a multistage fan cooled transformer (ONAN/ONAF/ONAF), the loss of a single stage of fan cooling would drop the maximum transformer rating to the first stage of fan cooling rating.
- The loss of both stages of fan cooling reduces the maximum transformer rating to the base transformer rating.

With 70MW (76.4MVA) required to operate the WTP, utilizing 60/80/100MVA transformers in Option 1, the WTP could operate at full capacity on a single A6 Substation transformer with one stage of fan cooling lost. If the second stage of fan cooling was lost, either the plant would have to operate at a reduced capacity ensuring that the electrical power consumption was less than 60MVA, or implement the IEEE Guide for Loading Mineral Oil Transformers, C57.91 section 9.5 Longtime Emergency Loading or section 9.6 Short-time Emergency Loading.

The URS Study recommends procuring the 60/80/100MVA transformers with:

- Fan motor watt or current sensing equipment with remote monitoring capability
- Air flow sensors with remote monitoring capability
- Spare fans, fan motors, temperature sensors and wiring harnesses.

With the above instrumentation, the performance of the transformer fan cooling components can be monitored in addition to transformer operating temperatures. The thermal time period of a transformer is large and by the time a transformer over-temperature condition is noticed the recovery options are greatly limited. The monitoring of transformer fan cooling components, will facilitate timely troubleshooting or replacement of faulty equipment before a transformer over-temperature condition is reached.

The URS Study also recommends that plans and procedures be proactively developed to address the loss of fan cooling system operation:

- Procedures on replacing defective components with spare components
- Procedures on removing components from the out of service transformer for replacing defective components
- Procedures to periodically test the fan systems.

3.0 DELIVERABLES

The following describes the deliverables derived from the WRPS and ORP correspondence:

- A written engineering report shall be prepared and submitted to ORP. The report shall have:
    - A table of contents, purpose, scope, background, acceptance criteria, results, input data, assumptions, method of analysis, and executive summary
    - Details of the options studied, methodologies, and alternatives
    - Cost estimates for implementing the studied options
    - Advantages, disadvantages and limitations of options studied
    - Listing of identified options
    - Recommendation of preferred options.
- Two electronic copies of all input, reports, analyses, and calculations shall be provided to ORP, on two compact discs (CD) unencrypted for future use with:
    - Complete system information, such as cables, raceway, transformers load/classification, utility, etc., shall be provided in the report files.
    - All electronic media shall be prepared in Hanford Site standard software format (i.e., Microsoft Office).
- The final engineering report shall be stamped/sealed, signed and dated by a currently licensed Washington State Registered Professional Engineer.

APPENDIX A

URS STUDY

Title: Analysis of Power Delivery to the WTP to Achieve a Minimum of 70MW (76.4MVA)

Project Name: Analysis of Power Delivery to WTP

Project Number: 29906

URS Study Number: 17-05-110-001

Revision Number: 0

Date: September 02, 2010

number of pages 126

Project Name: Analysis of Power Delivery to WTP

Project Number: 29906

URS Study Number: 17-05-110-001

WRPS Report Number: RPP-RPT-46992

ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW (76.4MVA)

PREPARED FOR

Department of Energy, Office of River Protection

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STUDY REVISION PAGE

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ACRONYMS

AHJ – Authority Having Jurisdiction

ASD - Adjustable Speed Drive

BNI – Bechtel National, Inc.

BOD – Basis of Design

BOF – Balance of Facility

BPA – Bonneville Power Administration

CCN – Correspondence Control Number

DOE – Department of Energy

EPC – Engineering, Procurement, and Construction

EPC&C – Engineering, Procurement, Construction, and Commissioning

EU- Hanford Electrical Utility

HLW – High Level Waste

ICD – Interface Control Document

IEEE- Institute of Electrical and Electronic Engineers

LAW – Low Active Waste

MSA – Mission Services Alliance

NEMA – National Electrical Manufactures Association

ORP – Office of River Protection

PEP – Project Execution Procedure

PFCS – Power Factor Correction System

PSAR – Preliminary Safety Analysis Report

PWM - Pulse Width Modulated

ROM – Rough Order of Magnitude (-30% to +50% accuracy)

SLD – Single Line Diagram

TF – Tank Farm (Hanford 200 Area)

TIC – Total Installed Cost

UPS – Uninterruptible Power Supply

VFD – Variable Frequency Drive

WRPS – Washington River Protection Solutions

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WTP – Waste Treatment and Immobilization Project

ABBREVIATIONS

Bldg – Building

kV – Kilovolts

MVA - Megavolt Ampere

MW – Megawatts

OA/FA/FA – Oil Immersed Air Cooled (Natural Convection), with two stages of fans for forced air cooling

pf – Power Factor

Swgr – Switchgear

Xfmr – Transformer

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EXECUTIVE SUMMARY

Washington River Protection Solutions (WRPS) has been contracted by the Department of Energy (DOE) Office of River Protection (ORP), to perform a study that includes the following:

1. Review and comment on the Waste Treatment Plant (WTP) Power System Load Flow Analysis, 24590-WTP-E1C-MVE-00004 Rev. E (Ref. #1), hereafter referred to as the "WTP Load Flow Analysis."
2. Review and comment on the Feasibility Study To Use The Present 13.8kV Construction Power As The Fifth Feeder To WTP, 24590-WTP-ES-E-09-001 Rev 0 (Ref. #2), hereafter referred to as the "Fifth Feeder Study."
3. Develop a Rough Order of Magnitude (ROM), of -30% to +50% accuracy, cost benefits analysis and ROM schedule for implementation of a power factor correction system (PFCS) on the WTP based on Bonneville Power Administration's (BPA) power factor penalties.
4. Perform a Load Flow Analysis using SKM software, with corresponding files fully populated with existing site data to assess the Hanford 230kV system's capability to handle the 70MW (76.4MVA) WTP electrical loads, Hanford Site Expected Projected Loads, and current Hanford site loads.
5. Provide viable options - with ROM Total Installed Cost (TIC) to include Engineering, Procurement, Construction, and Commissioning (EPC&C) and ROM schedule - to increase electrical power delivery up to a minimum of 70 megawatts (MW) at 91.6% lagging power factor (76.4MVA), via a single power source, to the WTP.
6. Evaluate the operational impacts of loss of fan cooling for multistage fan cooled transformers; i.e., 60/80/100MVA ONAN/ONAF/ONAF transformers.

SUMMARY OF RESULTS

This is a high level conceptual study that is not intended to be a design document.

WTP Load Flow Analysis

The WTP Load Flow Analysis was performed utilizing commercial software (ETAP) with a methodology that follows industry standards. The demand factors utilized in the WTP Load Flow Analysis are within the range of industry standards and the assumptions made show reasonable engineering judgment.

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Based on the review of the WTP Load Flow Analysis and on the current A6 Substation configuration, this study recommends that Interface Control Document for Electricity (ICD-11, Ref. #3) be revised to reword the first paragraph of section 1.4.2 to modify the requirements for future margin, as follows:

> *"The maximum average operational power for the WTP is limited to 95.6MVA. For the purpose of design, a 30% operational growth margin shall be maintained to the point of title III complete for calculating the maximum average electrical power utilized for WTP facility operations. If electrical losses are not accounted for in the software utilized to calculate the maximum average operational electrical power requirements, an additional 5% electrical loss margin shall be included."*

The first sentence of this recommendation is based on Option 1 of the alternatives studies for increasing system capacity to 70MW. Should a different maximum MVA option be selected that maximum MVA value should replace the 95.6MVA currently displayed.

This recommendation is based on DOE's direction to BNI in CCN 194415 (Ref. #7), CCN 200152 (Ref. #5) and on the industry standard, IEEE 141, section 2.4.1.4 Forecasting and Planning, for projected load growth of an operational facility with a projected 40 year life span.

This study also recommends that ICD-11 specify electrical design or operational power limitations in terms of Apparent Power (MVA or kVA) or that power limitations be specified in terms of Real Power (MW) including a minimum power factor.

With the existing 53MW calculated in the Power System Load Flow Analysis (Ref. # 1 Section 8.1) and IEEE 141 recommended 30% operational load growth results in 69MW of expected load through the life of the WTP, the present A6 substation capacity is not expected to support the electrical needs for the life of the plant.

<u>Fifth Feeder Study</u>

This study's review of the Fifth Feeder Study finds the Study to be reasonable in its method, assumptions, and conclusions; based on the available information presented for review. However, converting the A8 construction 7MW (7.6MVA) feeder for permanent use of WTP does not, by itself, meet the requirement to provide 70MW at 91.6% power factor (76.4MVA) as required by DOE in the commissioning of this study. The Fifth Feeder would only bring the total WTP electrical power capacity to approximately 62MW (67.7MVA) based on the stated 55MW (60MVA) of available capacity from the A6 Substation.

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Power Factor Correction System Cost/Benefit Analysis

This study does not recommend the implementation of a PFCS solely for the purpose of power factor correction since BPA does not currently charge the Hanford 230kV Utility Operator a power factor correction penalty (Att. #8).

Hanford 230kV Electrical Utility System

The Hanford 230kV electrical utility system SKM files that were provided for review were missing key electrical system component information that precluded the ability to perform the required system analysis.

Based on the preliminary analysis completed by this study, the Hanford 230kV system capacity is approximately 268MVA, which includes the A6 substation feeder lines.

Based on the prior statement, no modifications to the 230kV system would be required in order to deliver 70MW (15MW more than what is currently allocated) at 91.6% pf (76.4MVA) to WTP as was contracted in this study; pending further evaluation and concurrence by BPA.

The Hanford projected electrical load is approximately 180MVA or 67% of the Hanford 230kV system capacity.

> *Since nearly all of the Hanford 230kV system projected electrical loading is either directly or indirectly supporting the WT, it is the recommendation of this study that a solution addressing the projected Hanford 230kV system load growth be considered in place of the narrow scope contracted in this study - to evaluate options that provide 70MW @ 91.6% pf to the WTP.*

The Hanford 230kV A6 Substation Expansion option presented by DOE-RL in the review meeting (Ref. #26) for this study (held on July 22, 2010) and presented in this study, satisfactorily addresses the specific WTP present and future project electrical demands as well as the other 200 Area electrical loads that are presently being developed to support the WTP project.

> *Since this option addresses both the criteria outlined in the commission of this study for the WTP electrical load demands as well as the projected electrical load demands of the Hanford site 200 Area, this option is the overall recommended option of this study to provide electrical power to the WTP and the projected Tank Farm Loads.*

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Viable Options to Deliver a Minimum of 70MW (76.4MVA) to the WTP

The recommendation of this section is solely to comply with the original scope of the contract that requires a recommended option for the supply of a minimum 70MW (76.4MVA) of electrical power to the WTP. This section, therefore, does not account for the deficiency of the Hanford 230kV system in handling projected loads. Both issues must ultimately be handled concurrently so that an efficient solution (technically and economically) can be provided. Hence, the overall recommended option reported in the SUMMARY OF RESULTS section should receive a higher priority by DOE.

This Study presents 10 options for evaluation; 9 options specific to WTP plus 1 option that addresses both WTP and the projected Tank Farm (TF) Loads. Of the 10 options presented Option 1 - A6 Substation Electrical Equipment Upgrade (Two 60/80/100MVA transformers and two 13.8kV, 4,000A switchgear), is the recommended option.

Option 1 is recommended for the following reasons:

- Option 1 meets the functionality requirement of providing a minimum of 70MW (76.4MVA) of electrical power.
- It provides up to 95.6MVA (limited by the 4,000 amp switchgear).
- It maintains the same level of reliability as the current electrical configuration. second highest of the options reviewed.
- It offers the second lowest ROM TIC ($12.3M) of the options that meet the 70MW (76.4MVA) requirement.
- It has the shortest time for implementation of 2 years.

Option 7 was the lowest cost option at $10.5M TIC and the option with the highest reliability due to fewest components. However, there are jurisdictional issues associated with Option 7, which would place four of the switchgear in Building 87 under two different contractual authorities resulting in greater schedule and cost risk. Since Option 1 maintains the same electrical configuration as is currently employed in the A6 Substation, maintaining the same jurisdictional boundaries that exist in the current operations contracts and WTP Project contract, Option 1 eliminates both the cost and schedule risks that are associated with Option 7. It should also be pointed out that both Option 7 and Option 1, in terms of cost, fall within the ROM -30% +50% accuracy of the estimate. The basis for selecting Option 1 over Option 7 is discussed further in the conclusion of this study.

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Loss of Transformer Fan Cooling

The transformer manufacturer's directions for transformer operations (loading) should be followed. If the transformer is to be operated outside of the transformer manufacturer's recommended range of operation, the transformer manufacturer should be consulted. In addition to the manufacturer's recommendation, IEEE C57.91 Appendix H Section H.3 states the following:

- For a multistage fan cooled transformer (ONAN/ONAF/ONAF), the loss of a single stage of fan cooling would drop the maximum transformer rating to the first stage of fan cooling rating.
- The loss of both stages of fan cooling reduces the maximum transformer rating to the base transformer rating.

With 70MW at 91.6% power factor (76.4MVA) required to operate the WTP, utilizing 60/80/100MVA transformers (Option 1) at the A6 Substation, the WTP could operate at full capacity on a single A6 Substation transformer with one stage of fan cooling lost. If the second stage of fan cooling was lost, either the plant would have to operate at a reduced capacity ensuring that the electrical power consumption was less then 60MVA, or implement the IEEE Guide for Loading Mineral Oil Transformers, C57.91 section 9.5 Long-time Emergency Loading or section 9.6 Short-time Emergency Loading.

This study recommends procuring the 60/80/100MVA transformers with:

1. fan motor watt or current sensing equipment with remote monitoring capability
2. air flow sensors with remote monitoring capability
3. spare fans, fan motors, temperature sensors and wiring harnesses.

   With the above instrumentation, the performance of the transformer fan cooling components can be monitored in addition to transformer temperatures. The thermal time period of a transformer is large and by the time a transformer over-temperature condition is noticed the recovery options are greatly limited. By monitoring the transformer fan cooling components, this will facilitate timely troubleshooting replacement of faulty equipment before an over-temperature is achieved.

   Plans and procedures should be proactively developed to address the loss of fan cooling system operation.

4. Procedures on replacing defective components with spare components
5. Procedures on removing components from the out of service transformer for replacing defective components.
6. Procedures to test the fans frequently

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Basis for Cost and Schedule Estimate

The power factor correction unit pricing and fabrication schedule are based on a vendor, NEPSI, budgetary pricing quote (Att. #1).

The transformer and switchgear pricing information and fabrication schedules are based on a vendor, ABB, verbal budgetary pricing quote.

The remaining pricing information is based on URS standard estimating rates and factors (Att. #2); with the schedule information based on engineering judgment.

Table 1 Options Reviewed to Deliver a Minimum of 70MW (76.4MVA) to the WTP

Option	Description	Functionality	Reliability	Cost/Schedule
1	Upgrade Transformers, 60/80/100MVA; Upgrade Switchgear A-6 Substation; 4,000A	Meets the 70MW requirement, with 91.6% pf	Dual redundant line-up	$12.3M / 2 Yr
2	Upgrade Transformers; 60/80/100MVA; add two 3,000A Switchgear & 1 new Switchgear building.	Meets the 70MW requirement, with 91.6% pf	Dual redundant line-up	$18.4M / 2 Yr Not Considered Cost Viable, due to insufficient space in A6 Substation switchgear building
3	Add two Transformers; 37/50/62 MVA; upgrade A-6 Substation ; 4,000A Switchgear	Meets the 70MW requirement, with 91.6% pf	Dual redundant line-up	Cost Not Estimated. Not Considered Cost Viable, due to insufficient space in A6 Substation switchgear building

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4	Add two Transformers; 37/50/62 MVA; and associated new switchgear; add two 3,000A Switchgear & 1 new Switchgear building.	Meets the 70MW requirement, with 91.6% pf	Dual redundant line-up	$17.5M / 2 Yr Not Considered Cost Viable, due to insufficient space in A6 Substation switchgear building
5	Add one Transformer; 37/50/62 MVA; and associated new switchgear vertical sections with 3,000A breakers; add 230kV primary breakers; add two 3,000A busduct.	Meets the 70MW requirement, with 91.6% pf	Dual redundant line-up	$12.6M / 2 Yr Not Considered Cost Viable, due to insufficient space in A6 Substation switchgear building
6	Warehoused Spare 37/50/62MVA Transformer. Allows timely replacement of transformer at minimum cost.	Does NOT meet the 70MW requirement, with 91.6% pf	Dual redundant line-up	$1.5 M /1 Yr
7	Upgrade Transformers, 60/80/100MVA with 3 windings; Eliminate A6 Switchgear & direct feed power from transformers.	Meets the 70MW requirement, with 91.6% pf	Dual redundant line-up	$10.5 M /2 Yr
8	Remove the requirement of 100% Electrical Load Operations while on one Transformer.	Does NOT meet the 70MW requirement, with 91.6% pf	Single redundant line-up	Not Considered Viable, due to ability to overload a single transformer as the result of automatic transfer switch operation.

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9	Concurrent implementation of 5th feeder and capacitor banks	Does NOT meet the 70MW requirement at 91.6% pf.	Dual redundant line-up	Not Considered Viable, due to inability to meet 70MW requirement.
10	Hanford 230kV A6 Substation Expansion	Meets the 70MW requirement @ 91.6% pf plus addresses projected TF Loads necessary to support the WTP.	Dual redundant line-up	$20.2M / 2 Yr

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I. PURPOSE

There are six distinct but interrelated purposes of this study, listed below:

1. To validate the results of the WTP Load Flow Analysis, issued by the WTP project, to confirm if the electrical utilities power source (A6 Substation) to the WTP is undersized based on the current calculated load and the DOE required 15% contingency and 15% Design margin.
2. To validate the results of the Fifth Feeder Study, issued by WTP project, as a means to mitigate the overload condition of the A6 Substation. Additionally, to evaluate the cost effectiveness of this option against the other options presented in this study.
3. To determine if a PFCS is cost effective to implement on the WTP project based on BPA power factor correction penalty of 97%.
4. To verify the Hanford 230kV system is capable of handling the 70MW (76.4MVA) WTP electrical loads, Hanford Site Projected Loads, and current Hanford site loads.
5. To recommend a reliable, cost effective means to provide a minimum of 70MW at 91.6% pf (76.4MVA) of electrical power to the WTP while operating on a single A6 Substation power source (Train A or Train B).
6. For a transformer with two stages of forced air cooling, to specify the maximum transformer operating MVA rating during a loss of each stage of cooling.

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II. SCOPE

This study will perform the 6 actions commissioned by DOE as described below.

A. Review and Comment on the WTP Load Flow Analysis

The review the WTP Load Flow Analysis (Ref. #1) will be limited to the below sections as specified per scope of work attached to the letter to Ms. S.E. Bechtol, Contracting Officer, U.S. Department of Energy, Office of River Protection, Contract number DE-AC27-08RV14800, document number WRPS-1000326 R2.

1. Section 2.3 Acceptance Criteria

2. Section 5.0 Methodology

3. Section 6.0 Assumptions

4. Section 8.1 Maximum Power Demand

B. Review and Comment on the Fifth Feeder Study

This study will review and comment on the Fifth Feeder Study (Ref. #2) for technical accuracy, compliance with industry standards, and consistency with standard engineering practices in assessing the options reviewed and recommendation of the study. Additionally, the study will assess the use of the Fifth Feeder both as an independent option and in conjunction with other options presented.

C. WTP Power Factor Correction

Evaluate the economics of implementing a PFCS on the WTP. Perform a cost benefit analysis based on the Hanford Site Electrical Utility operators billing information, as it pertains to a power factor penalty for operating below a lagging 97% pf. The cost benefit analysis will include TIC ROM (per URS Project Execution Procedure (PEP) 301 Estimating Form 301-02(s) General Estimating Guidelines for Order of Magnitude Estimates) cost, schedule, and additional system capacity obtained as the result of implementing a PFCS. This study will also comment on the feasibility of implementation of a PFCS in conjunction with the options reviewed to achieve a minimum of 70MW (76.4MVA) of electrical power to the WTP.

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D. Hanford 230kV Electrical Utility System

This study will assess the Hanford 230kV system for capability to handle the 70MW (76.4MVA) WTP electrical loads, Hanford Site Projected Loads, and current Hanford site loads.

E. Options to Provide a Minimum of 70MW (76.4MVA) of Electrical Power to the WTP

This study will evaluate several electrical design options to provide a minimum of 70MW (76.4MVA) of electrical power to the WTP based on the worst case condition of maintaining plant operations on a single A6 transformer. The review of each of the presented options will include a discussion covering the below areas:

- Functionality - Ability to meet the minimum 70MW (76.4MVA) requirement
- Reliability - A comparison of the reliability of each option to the reliability of the current design
- Risk – As compared to the current A6 Substation configuration
- ROM Cost Estimate - Expense of implementing the option
- ROM Schedule - Time required for Engineering, Procurement, Construction, and Commissioning. It does not include the DOE budgetary cycle.
- Advantages – Benefits of one option over another
- Disadvantages – Drawbacks of one option over another

Additionally, this study will recommend one of the options reviewed, based on the selection criteria outlined above.

F. Loss of Transformer Fan Cooling

For a two staged cooled ONAN/ONAF/ONAF transformer, this study will specify the IEEE C57.91 (Guide for Loading Mineral-Oil-Immersed Transformers) permissible loading allowance for the loss of a single stage of transformer forced air cooling and for a loss of both stages of transformer forced air cooling.

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III. CODES AND STANDARDS

A. American National Standards Institute (ANSI)

ANSI C84.1-2006 American National Standard for Electrical Power Systems and Electrical Equipment – Voltage Ratings (60Hz)

B. Institute of Electrical and Electronic Engineers (IEEE) Standards

IEEE Std 100 Standard Dictionary of Electrical and Electronic Terms

IEEE Std 141 Recommended Practice for Electric Power Distribution for Industrial Plants (Red Book)

IEEE Std 142 Recommended Practice for Grounding of Industrial and Commercial Power Systems (Green Book)

IEEE Std 241 Recommended Practice for Electric Power Systems in Commercial Buildings (Gray Book)

IEEE Std 242 Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems (Buff Book)

IEEE Std 399 Recommended Practice for Industrial and Commercial Power Systems Analysis

IEEE Std 493 Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (Gold Book)

IEEE Std 519 IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

IEEE Std 739 Recommended Practice for Energy Management in Industrial and Commercial Facilities

IEEE Std C57.91-1995 Guide for Loading Mineral Oil Immersed Transformers

C. National Electrical Manufactures Association (NEMA) Standards

NEMA MG-1 Motors and Generators

D. National Fire Protection Agency (NFPA) Standards

NFPA 70-1999 National Electric Code

E. National Electrical Safety Code

ANSI/IEEE C2-2007 National Electrical Safety Code (NESC), 2007 Edition

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IV. BACKGROUND

The WTP is a radioactive waste processing facility, located at the DOE Hanford site in Washington State, which is currently being designed and built with an approximate forecasted design completion date of 2013. The 2013 date is based on the DOE EM Construction Project Review, Overview and Assessment, presented by Frank Russo on May 3, 2010.

The WTP plant is intended to be supplied electrical power via the A6 Substation from the Hanford 230kV Electrical utility system, which is supplied electrical power from the BPA via two paralleled independent 230kV power sources, Midway Substation and the Ash Tap (Att. #5). The Hanford 230kV electrical utility system is administered by Mission Services Alliance (MSA) for the DOE.

The existing DOE A6 (251E) (Ref. #10 & Ref. #11) Substation is powered from the Hanford 230kV electrical utility system and is configured in a double ended electrical line-up. The two existing redundant A6 Substation transformers have a maximum continuous rating of 62MVA each at the second stage of forced air (fan) cooling, i.e., the transformers are rated as follows: 37/50/62MVA OA/FA/FA, 230-13.8kV, 3 PH, 60 Hz (Ref. #4 & #8). The two existing A6 Substation 13.8kV switchgear have a maximum continuous ampere rating of 3,000 amps or a maximum of 71.7MVA of electrical load carrying capability. Each utility substation transformer and associated load group switchgear feeders are 100% redundant, i.e., sized to provide power to the entire WTP plant electrical load if the other utility substation transformer or load group switchgear is unavailable (Ref. #15, section 8.2.1). The A6 Substation is solely intended for supplying permanent plant electrical power to the WTP. The A6 Substation is energized, but is currently only feeding the A6 Substation building services. The A6 Substation is forecasted for utilization by the WTP in the fourth quarter of 2011, per ICD-11 section 1.4.4.2 (Ref. #3).

For the electrical one lines associated with the Hanford 230kV electrical distribution system, the A6 Substation, and the WTP 13.8kV interfacing switchgear, refer to Ref. #4, #8, #9, and Att. #5.

BNI issued an updated revision of the WTP Load Flow Analysis (Ref. #1) on September 29, 2009; which stated in Section 8.1.1,

> *"The maximum power demand from the DOE substation for operation of RPP-WTP plant is determined to be 50.498MW @ pf of 91.6%, <u>excluding design growth and contingencies.</u>"(Ref. #1).*

Based on this calculated maximum power demand and DOE's direction to utilize 15% design growth and 15% Contingency (Ref. #7); results in a maximum electrical demand load of 71.7MVA on a single transformer. This calculated WTP electrical demand exceeds the 62MVA maximum electrical load capacity of the existing DOE A6 Substation transformers supplying power to the WTP.

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Taking action to address the calculated electrical over demand of the A6 Substation, the DOE commissioned the WTP project to evaluate options for utilizing the 7MW of electrical power from the A8 Substation for permanent plant use; here after referred to as the Fifth Feeder. As directed, the WTP project issued the Fifth Feeder Study which made a recommendation to utilize the 7MW of electrical power from the A8 Substation in support of the WTP standby load bus (MVE-SWGR-87003A & MVE-SWGR-87003B); for an estimated TIC of $5.5M.

The DOE A8 Substation supplies the WTP with temporary construction power per ICD-11 (Ref. #3 Table 1 item 3) which states,

> *"The Waste Treatment Plant Contractor Shall Consume up to 7MW of construction power at the defined interface point. Based on this project criteria the DOE A8 (251W) Substation is supplying a maximum of 7MW of electrical power at 13.8kV, via a single electrical feed on an overhead transmission line, to the WTP for temporary construction power."*

The A8 Substation is also supplied electrical power from the Hanford 230kV electrical power electrical utility system, similar to the A6 Substation.

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V. ASSUMPTIONS

A. WTP Load Flow Analysis

No assumptions made in the review of the calculation.

B. Fifth Feeder Study

No assumptions made in the review of the study.

C. WTP Power Factor Correction

Based on an email from MSA, the Hanford 230kV System Administrator, to DOE dated June 3, 2010 12:28 PM (Att. # 8) BPA does not charge the Hanford 230kV System a power factor penalty.

However, should BPA charge the Hanford 230kV system per the BPA Transmission Services, 2010 Transmission and Ancillary Services Rate Schedule (Ref. #19); the following assumptions were made to analyze the cost effectiveness for implementing a PFCS.

1. For a bounding condition and to determine the shortest time to return on investment, a lagging power factor of 80% is assumed at the full 70MW (87.5MVA) of electrical load.

2. For comparison purposes, an additional study was run assuming that the currently calculated pf of 91.6% lagging will exist at the full 70MW (76.4MVA) of WTP electrical loads. The 91.6% pf is assumed based on the WTP Load Flow Analysis (Ref. #1, Section 8.1.1).

3. The recommended placement of the automatic PFCS assumes that the utility metering point, for assessing the power factor, is the four 13.8kV, 2,000A, A6 switchgear feeder circuits to WTP.

   In theory, if the metering point was electrically upstream of the A6 switchgear, the PFCS could be interfaced at the A6 switchgear. This would need to be looked at closely due to physical space limitations within the A6 switchgear building. There is no physical space to add two new vertical sections to the existing switchgear; however, it appears that the existing switchgear has a single vertical section for a small station services transformer of 75kVA. It may be possible to change this one-high vertical section into a two-high vertical section with a 1200 amp frame breaker, in each switchgear, to interface the two required automatic PFCS.

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4. This study assumes that there are no significant harmonic interactions with the Capacitor Bank Automatic PFCS

   Adding capacitor banks may lead to adverse interactions with electrical systems containing non-linear loads due to the amplification of voltages at the system resonant frequency. This should be verified with a WTP load Harmonic analysis. The WTP Harmonic Load Analysis has not been completed at this time. It is forecasted to be completed on December 30, 2010 (Ref. #12).

   a) If the WTP Harmonic Load Analysis, shows harmonics to be an issue with the use of capacitor banks for power factor correction, automatic PFCS using tuned or partially tuned filters can be optimized to address IEEE 519 requirements as well as power factor correction. This is specialty work typically performed by the PFCS vendor on an operating facility.

   b) The cost estimate for implementation of the automatic PFCS assumes that the WTP switchgear MVE-SWGR-87001A, MVE-SWGR-87001B, MVE-SWGR-87002A, and MVE-SWGR-87002B have spare 1,200 amp frame breakers to interface the automatic PFCS. This assumption is based on the Switchgear Building 13.8kV Switchgear MVE-SWGR-87001A & 87001B Single Line Diagram (Ref. #13) and the Switchgear Building 13.8kV Switchgear MVE-SWGR-87002A & 87002B Single Line Diagram (Ref. #14), but needs to be validated with the WTP project.

5. The cost/benefit analysis assumes that the Hanford site electrical utility would charge the same power factor penalty as the BPA Transmission Services, 2010 Transmission and Ancillary Services Rate Schedule (Ref. #19)

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6. The cost/benefit analysis assumes a worst case lagging power factor of 80%. This is bounding, based on the current calculated lagging power of 91.6% (Ref. #1, section 8.1.1). The analysis also assumes a maximum electrical load of 70MW (87.5MVA), no PFCS operational cost, and no time value of money for determining the time for return on investment. These assumptions will result in the shortest possible time to return on investment. For the purpose of determining if the utilization of PFCS is economical, these are the bounding assumptions.

D. Hanford 230kV Electrical Utility System

Each of the below assumptions should be verified by the Hanford 230kV electrical utility operator.

1. This study assumes that should BPA use the 230kV system to "wheel" through power to customers outside of the Hanford 230kV system that BPA will ensure that the Hanford 230kV system capacity is not exceeded irrespective of the Hanford 230kV system loads in operation at the time that the wheeling of power occurs. Based on both BPA's knowledge of the Hanford 230kV system operational limitations and the power monitoring of the Hanford 230kV system, BPA is aware of the Hanford 230kV system loads at all times. As such, it is BPA's responsibility to ensure that the Hanford 230kV system is maintained within design parameters during power wheeling events.

2. Based on the information available for review of the Hanford 230kV system, this study assumes that the most limiting component is the Egret 636 MCM overhead transmission line (Ref. #20 and Ref. #21), with a base current rating of 798A per (Att. #9) and a site specific current rating of 673A per (Ref. #23).

E. Options to Provide a Minimum of 70MW (76.4MVA) of Electrical Power to the WTP

This study assumes that the assumptions made for the Hanford 230kV Electrical Utility System, Section V.D, are also valid for the options to provide a minimum of 70MW (76.4MVA) of electrical power to the WTP.

F. Loss of Transformer Fan Cooling

No assumptions made.

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VI. REVIEW AND COMMENT

A. WTP Load Flow Analysis

1. Section 2.3 Acceptance Criteria

a) Section 2.3.1 Power Demand

b) There is some ambiguity over the maximum average load demand for the WTP project, specifically relating to ICD-11. ICD-11, section 1.4.2 states,

> *"For planning purposes, the average electrical power for all the facility operations of the WTP is calculated at 41MW. Allowing for an estimated 5% electrical losses, 15% contingency, and 15% design growth, the final power requirement for full production is 55MW maximum average."*

The 5% electrical losses, 15% contingency, and 15% design growth, for the purposes of this study, will hence forth be called design margins.

The term "For planning purposes" is ambiguous and does not clearly state if the design margins are even required or at what point in the project they are required at. If the design margins are required, the phrase "For planning purposes" should be changed to "For the purposes of design". Additionally, the point in the project that these design margins are required should be specified; i.e., design complete, construction complete, start-up, etc.

Within the WTP Load Flow Analysis (Ref. #1), section 2.3.1 Power Demand, only partially quotes ICD-11, section 1.4.2,

> *"the final power requirement for full production is 55MW maximum average."*

This is also consistent with ICD-11 table 1 item 4. Neither of these statements indicates a requirement for a design margin to be included in the final WTP Load Flow Analysis.

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c) 2.3.2 Equipment Loading and 2.3.3 Voltage Regulation Limits

The review of these sections indicated that the criteria provided are appropriate and consistent with the reference material listed in the calculation, with a minor anomaly in the Range B Maximum voltage percents for 120 V, 480 V, and 4.16kV. The calculation shows a value of +5%, while ANSI C84.1, Table 1 has a value of +5.8% for each of these voltage levels. This is a minor issue and the values used in the WTP Load Flow Analysis are more conservative.

2. Section 5.0 Methodology

a) The methodology described and utilized in the WTP Load Flow Analysis are consistent with IEEE 399 Recommended Practice for Industrial and Commercial Power Systems Analysis for the overall development of the calculation.

b) The calculation implements section 2.4.1 Load Diversity of IEEE 141 Recommended Practice for Electric Power Distribution for Industrial Plants; specifically implementing section 2.4.1.3 Demand, which states the following,

> *"The sum of the electrical ratings of each piece of equipment will give a total connected, non-coincident load. Because some equipment operates at less than full load and some intermittently, the resultant demand upon the power source is always less than the total connected load, so appropriate load diversity considerations should be considered in the analysis. In general, equipment diversities range from slightly less than 100% for continuous process to as low as 2% to 5% for certain types of press and welding operations. The diversity expectation associated with each type of equipment should be used to develop a specific, total, actual expected load. An appropriate diversity should then also be applied to each large grouping of equipment and to the entire load to reflect randomness and physical reality, based on experience."*

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The WTP Load Flow Analysis used a 91% diversity factor, based on engineering judgment and defends the use in section 6.2 of the calculation. This study concurs that this factor is conservative as well; since a 91% diversity factor would be appropriate for a continuous process, yet both the HLW and LAW facilities have a batch type processes (non-continuous).

It should also be pointed out that load flow studies for large electrical distribution systems are typically conservative. This is due to the utilization of the diversity factor at each level of distribution; i.e., first at the panel board, then the Motor Control Center, then Local Switchgear, and finally the site switchgear. In terms of electrical power flow, as you go closer to the utility the probability of having 91% of the loads operating at the same time is less and less likely.

c) Loading Factors, Diversity Factors, and Standby Loading Factors were based on the Authority Having Jurisdiction (AHJ) approval (Ref. #17).

(1) Loading Factor

The AHJ has approved the loading factor as being defined as the designed Breaking Horsepower divided by the motor name plate rating. This factor is taking credit for the difference in the designed power needed for mechanical operation and the next available standard size larger motor to drive the mechanical load. This is an industry standard practice for calculating electrical load; as such, this study concurs with this method.

(2) Diversity factor

The diversity factor was approved by the AHJ for the same reasons previously discussed in section b) above.

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(3) Standby Loading Factor

The AHJ approved a 0% standby loading factor. This is effectively a 0% duty cycle for the spare/redundant loads. This factor is reasonable based on industry standard operations for standby/spare equipment. Operations does not typically operate standby/spare equipment in parallel with the in service equipment, other than to momentarily (few minutes) switch in service equipment to balance run time between in service and standby/spare equipment. Ultimately, the diversity factor utilized in the Load Flow Analysis, discussed in section b) above, accounts for this momentary paralleling of mechanical loads.

3. Section 6.0 Assumptions

a) For the Loading Factors, Diversity Factors, and Standby Loading Factor that were approved by the AHJ (the legal authority to make this decision); these are inputs to the calculation and not assumptions. The AHJ has reviewed and approved the basis for the various factors applied to the list of loads and provided them to the project for use for this calculation.

b) The WTP Load Flow Analysis shows reactive load for electrical loads with non-linear power supplies i.e., VFD, ASD, UPS, etc. For the loads having Pulse Width Modulated (PWM) power supplies, they would have nearly a unity power factor and little to no reactive load. If in the interest of conservatism, the benefit of the high power factor of PWMs should have been mentioned in the calculation.

Using the motor power factor and not taking credit for the nearly unity power factor for the PWM VFD will result in a higher load current and overall higher Apparent Power requirement for the electrical system.

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However, the larger melter power supply loads do take credit for being PWM power supplies, yet the smaller motor loads with VFD and UPSs do not. Since there is relatively a small number of loads with PWM power supplies, both in terms of quantity and kVA loading, this may only result in a minimal change in the overall plant power factor and MVAR loading.

c) There is no discussion in the calculation regarding the basis for the power factor chosen for the lumped loads. Attachment A-3, ETAP Input Data Lump Loads, included Mechanical Package Power Panels (Ref. #1) that lists 486 assorted loads all with a 85% pf. Without having more information on these loads it is impossible to say if this is a bounding assumption. However, one must realize that the given information is in terms of kVA; in other words, the total current is not going to change for these loads, but only the ratio of real versus reactive currents. This would impact the total WTP power factor and if required, the sizing of a PFCS.

4. Section 8.1 Maximum Power Demand

a) Based on CCN 19611 (Ref. #6) from the WTP Project Manager to DOE, dated Apr. 09, 2009 stated in part,

> *"The Total electrical power demand of 55MW stated in Interface Control document (ICD)-11 (Reference 3) was an estimate based on electrical load analysis performed in 2002. This corresponded to a calculated electrical load of 41MW and reflected the approved scope and maturity of the design at that point in time. Since the procurement of plant process equipment was in the preliminary stage and the number of confirmed electrical loads was limited, a conservative contingency of 15% and allowance for design growth of 15% were applied to determine the total electrical power demand."*

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This would indicate that in approximately 7 years the total calculated load has gone from 41MW to 50.5MW or has increased by ~23%. This equates to an approximate annual load growth of 3.3%. Assuming a design completion date of 2013 or another 4 years from the time of the current revision of the WTP Load Flow Analysis and a linear load growth in electrical loads (or another 13.2% load growth), this would equate to a final project load of 57.2MW.

Typically, a project's load growth does not grow linearly over the life of a project, but is a function that decays asymptotically towards the final design complete load. In the case of WTP, with the number of years left to go prior to design complete and with the technical issues outstanding and yet to be resolved, the 15% design growth factor still seems prudent.

As further support for the 15% design growth, IEEE-141 section 2.4.1.4 Forecasting and Planning, section a) states,

> *"Impact of nominal load growth over time. Typically, some slight growth in kilowatt demand will be experienced over time. This may be upwards of ½ to 1% per year."*

With the expected life of the plant to be 40 years and using the ½% load increase, $P = 57.2\text{MW} * (1 + .005)\text{^}40$ =69.8MW or another 22% load growth over the operational life of the project.

B. Fifth Feeder Study

The Fifth Feeder is the name given by the WTP project to the temporary construction power feed from the DOE A8 Substation, currently provided to the WTP for up to 7MW of temporary power for utilization during construction of the WTP facility (Ref. #3, Section 1.4.4). The Fifth Feeder Study analyzes the possible use of the temporary power feeder as a permanent supply to help reach the expected needed capacity.

The 13.8kV WTP temporary construction power is laid out in a ring configuration around the WTP site with 16 transformers taping off supporting the construction electrical power needs of the WTP project (Ref. #2 Appendix A, 24590-BOF-FSK-CON-E-05-005 Rev. 2, Field Sketch 13.8kV Temporary Power Distribution Single Line).

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1. Review Comments

a) ICD-11 Section 1.4.4, first paragraph, second sentence (Ref. #3), in reference to the Fifth Feeder states,

> *"Temporary construction power will not have redundant source."*

Additionally, it was identified that both the Fifth Feeder and WTP train A are fed from the A8 Substation. Thus, there is the potential to lose both the Fifth Feeder and the Train A portion of Substation A6. However, the Hanford site 230kV network is operated in a loop configuration, such that it would take more than one event to cause the loss of both the Fifth Feeder and the A6 Substation train A power source. Refer to Att. #5, Ref. #8, Ref. #9, and Ref. #18

b) Option 1 – Fifth Feeder Supplying Electrical Power to the Existing pad-mounted construction power transformers and cabling to power non-process related supporting facilities

Under Section 2 Recommendations, Option 1 was eliminated,

> *"because of its inability to utilize the 7MW capacity added to the system."*

Yet, only B51 Administration Building, B52 Warehouse Building, and B56 Combo Shop (approximately 15% of the 20+ BOF buildings.) were chosen as loads for this option. Appendix A of the Fifth Feeder Study (Ref. #2) shows 16 temporary construction transformers throughout the WTP site potentially able to support many more of the Balance of Facility buildings. This would imply that additional electrical loads (BOF building) could have been chosen to approximately meet the total 7MW load demand required in the evaluation criteria; however, the executive summary, under Option 1, implies that these loads were chosen since they were "non-process related supporting facilities". Yet this criterion was not listed in the Criteria section, section 3.1, and this same criterion was not made for any of the other 3 options presented in the study. This leads directly to the next point.

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c) Option 2 – Routing the "fifth power feeder" to the Pretreatment Facility (PTF) and connecting it to the PTF 13.8kV switchgear.

Appendix F, of the Fifth Feeder Study (Ref. #2), indicates that the normal electric plant configuration for this option has the WTP loads normally fed from the A6 Substation with a feeder from A8 interlocked to supply backup power to either bus. With the abnormal condition, i.e., loss of either A6 Substation transformer A or B, the PTF bus MVE-SWGR-10001A&B would be transferred to the Fifth feeder from the A8 Substation. This option provides flexibility for using the Fifth Feeder to supply an additional 7MW on loss of either transformer.

d) Option 3 & 4

As BNI indicated in the study, electrically both options are essentially the same, with only physical differences in implementation.

Option 3 – Routing the "fifth power feed" to the BOF 13.8kV switchgear building B87 and connecting it to the standby power switchgear. This option requires new outdoor switchgear to be installed near the building.

Option 4 – An alternate of Option 3. This alternate eliminates the new outdoor switchgear and retrofits the existing and installed standby switchgear to accept the "fifth power feed".

(1) Neither Option 3 Appendix G or Option 4 Appendix H or the Fifth Feeder Study states what is intended to be the normal configuration for either of these options. This would leave the following two possibilities

(a) A6 as the normal line-up and the A8 (Fifth Feeder) as the alternate line-up for MVE-SWGR-87003A&B

(i) This effectively makes the Fifth Feeder a standby power source, only being utilized during a loss of one of the two A6 power sources. This essentially removes 7MW of load off of the remaining A6 power feed; or put in another way, allows 7MW of additional power to be supplied to the WTP during a loss of one of the A6 Substation feeds.

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(ii) Another scenario is possible from this configuration that is not discussed in the Fifth Feeder Study; the possibility of losing both A6 feeds (i.e., fire in the A6 switchgear building) to the WTP facility, while still maintaining the Fifth Feeder. This would allow additional insurance for the standby loads, above the current capacity of the standby diesel generator.

(b) Fifth Feeder (A8 Substation) as the normal line-up and the A6 Substation as the alternate line-up for MVE-SWGR-87003A&B

In this configuration, loss of the Fifth Feeder would cause a partial loss of power in HLW, LAW, and BOF. Specifically, HLW MVE-SWGR-30002A&B, LAW LVE-SWBD-20101 & LVE-SWBD-20102, and BOF LVE-LC-91004 would lose power for the duration of time necessary to switch from the Fifth Feeder back to the A6 Substation feeders. LVE-LC-91004 supplies electrical power to the Glass Former Storage Facility, the Cooling Tower, Water Treatment Facility, The Non-Dangerous/Non-Radioactive Effluent Facility, Ammonia Facility, the South Fire Water Pump House, and the Fuel Oil Facility. The WTP production processes would have to be reviewed, but based on the loss of each of these loads; it would likely necessitate a complete shutdown of the WTP in order initiate an organized restart.

2. Fifth Feeder Interactions with 70MW (76.4MVA) Options

The Fifth Feeder can be implemented with any of the options reviewed. In itself, the Fifth Feeder cannot meet the 70MW (76.4MVA) requirement as specified by DOE for this study. However, used as a standby power source, this option can increase the plant operational power to 62MW (67.7MVA) (55MW + 7MW; current ICD power allowances) during a loss of one of the A6 transformers or switchgear.

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VII. POWER FACTOR CORRECTION

Based on an email from MSA, the Hanford 230kV System Administrator, to DOE dated June 3, 2010 12:28 PM (Att. # 8) BPA does not charge the Hanford 230kV System a power factor penalty. As long as this agreement exists between BPA and the Hanford 230kV System Administrator, there is no cost benefit to implementing a PFCS. The below cost analysis was performed should this agreement change, to evaluate the implementation of a PFCS based on the BPA Transmission Services, 2010 Transmission and Ancillary Services Rate Schedule (Ref. #19). The rest of the analysis and statements in Section VII are based on BPA assessing a power factor penalty.

Power Factor is defined as the ratio of Real Power to Apparent Power and should be accompanied by a description of leading or lagging; referring to a primarily capacitive or inductive electrical load system, respectively and from the perspective of the user (versus the generator). In practice, most industrial plants are inductive in nature and it has become common to drop the lagging descriptor when discussing power factor; unless the electrical load is capacitive or leading at which time the power factor would be called out as leading.

Power Factor Correction is the use of capacitive or inductive reactance (in various configurations such as capacitor switching) to obtain a desired power factor. This is desired to minimize the reactive current flowing in an electrical distribution system, which does no real work and limits the amount of real current or real power that can be provided to the electrical loads. In many cases, the electrical utility provider will assess a power factor penalty on a customer if the customer does not maintain the plants power factor above a specified value; in the case of BPA, 97% (Ref. 19).

Power Factor Correction can be implemented at the load or at the service entrance on the load side of the utility metering point. Generally, correcting the power factor as close to the source of reactive load minimizes the amount of reactive current that is flowing in the electrical distribution system, thus minimizing the size of the associated electrical equipment. For this study, Power Factor Correction will only be reviewed for applicability at the electrical service entrance of WTP (Building 87). Power Factor Correction at each reactive load would have to have been accounted for in the equipment layout of the plant to provide adequate space for the power factor correction equipment.

A. PFCS Sizing

1. Calculation to Determine the Capacitive Load Required to obtain a 97% lagging pf on the WTP Electrical Distribution System at Current Electrical Loads.

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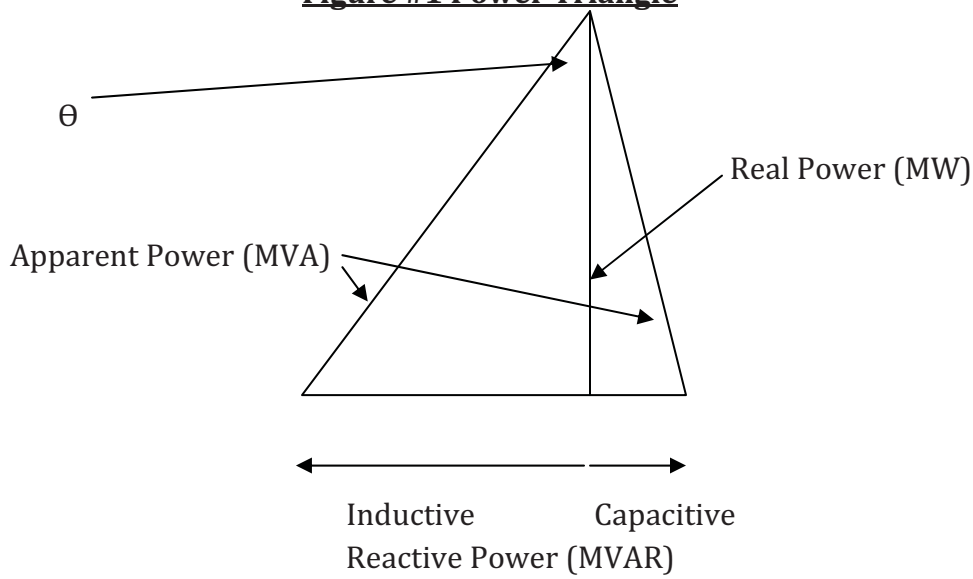
Figure #1 Power Triangle



a) Equation #1

$$pf = \cos\theta = \frac{Real\ Power\ (MW)}{Apparent\ Power\ (MVA)}$$

b) Equation #2

$$Apparent\ Power\ (MVA) = \sqrt[2]{\left(Real\ Power\ (MW)\right)^2 + (Reactive\ Power\ (MVAR))^2}$$

c) Using the 50.498MW at a lagging pf of 91.6% (Ref. #1, section 8.1.1). Determine plant MVAR at 91.6% lagging pf

$$Reactive\ Power\ (MVAR) = Real\ Power\ (MW) * tan\ (cos^{-1}(p.f.))$$

$$Reactive\ Power\ (MVAR) = 50.498MW * tan\ (cos^{-1}(.916))$$

Reactive Power = 22.116MVAR

d) Determine plant MVAR at 97% lagging pf

$$Reactive\ Power\ (MVAR) = Real\ Power\ (MW) * \tan\ (\cos^{-1}(p.f.))$$

$$Reactive\ Power\ (MVAR) = 50.498MW * \tan\ (\cos^{-1}(.97))$$

Reactive Power = 12.7MVAR

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e) Size of Capacitor Bank(s) required to achieve 12.7MVAR lagging

MVAR of Capacitor Bank = MVAR at 91.6% lagging pf – MVAR at 97% lagging pf

MVAR of Capacitor Bank = 22.1MVAR – 12.7MVAR= 9.4MVAR

B. Capacitor Bank Sizing

Determine the size of the capacitive bank(s) needed for the PFCS at 70MW (76.4MVA) of plant electrical load, assuming the current 91.6% lagging power factor. This is only an estimate for discussion purposes. For a more accurate calculation of the power factor at 70MW (76.4MVA), the "electrical" location and type of expected load must be input into the calculation.

1. Calculation to Determine the Capacitive Load Required to Obtain a 97% lagging pf on the WTP Electrical Distribution System at 70MWs.

a) Using the 70MW at a lagging pf of 91.6%, determine plant Reactive Power (MVAR).

$$Reactive\ Power\ (MVAR) = Real\ Power\ (MW) * \tan\left(\cos^{-1}(p.f.)\right)$$

$$Reactive\ Power\ (MVAR) = 70MW * \tan\left(\cos^{-1}(.916)\right)$$

Reactive Power = 30.7MVAR

b) Determine plant MVAR at 97% lagging pf

$$Reactive\ Power\ (MVAR) = Real\ Power\ (MW) * tan\left(cos^{-1}(p.f.)\right)$$

$$Reactive\ Power\ (MVAR) = 70MW * tan\left(cos^{-1}(.97)\right)$$

Reactive Power = 17.5MVAR

c) Size of Capacitor Bank(s) required to achieve 17.5MVAR lagging

MVAR of Capacitor Bank = MVAR at 91.6% lagging pf – MVAR at 97% lagging pf

MVAR of Capacitor Bank = 30.7MVAR – 17.5MVAR= 13.2MVAR

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C. Passive or Fixed PFCS

A fixed PFCS is the use of a single bank of capacitors sized specifically for a fixed operating inductive (motor) load or group of inductive loads to obtain a desired power factor. This form of power factor correction is most effectively used when electrically connected, in terms of power flow, downstream of the point of electrical motor load isolation. The point of electrical connection is such that when the motor loads are not operating the capacitor bank is also not operating. This form of power factor correction is not well suited for single overall plant PFCS.

1. Advantage

Having the capacitor bank located at the load minimizes the electrical components that are subjected to the additional reactive current that will oscillate between the inductive motor loads and the capacitor bank.

2. Disadvantage

a) Fixed PFCS are not well suited for a single overall plant PFCS, especially when the electrical system is supporting a batch process system, such that the motor loads will statistically change severely over time.

b) A fixed capacitor bank for each load requires substantially more floor space as compared to a single active PFCS.

c) PFCS may create adverse harmonic voltage interactions with non-linear loads.

3. Cost

Since this option is unsuitable for the WTP, pricing information was not obtained.

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4. Schedule

Since this option is unsuitable for the WTP, a schedule was not developed.

5. Recommendation

The Passive or Fixed PFCS is not recommended for the WTP, mainly because the WTP uses a batch process system. In addition, the WTP has an automatic load transfer system that makes it more complex, and less effective to use fixed size capacitor banks as an overall plant PFCS; since the loads on any given bus can automatically be shifted from one bus to another.

D. Active/Automatic PFCS Using Capacitor Banks

An automatic PFCS is made up of power monitoring relays, a control system, switching devices (breakers, contactors, etc.), and multiple banks of capacitors. Capacitor banks are automatically switched to maintain the desired power factor. This type of system can be designed to be interfaced with the electrical system at the service entrance, electrically below the utility metering point. In the case of the WTP, with four 13.8kV buses with load group A & B tie breakers and lower level automatic tie breakers; four (4) automatic power factor correction units would be expected. Each power factor correction unit will need to be sized to correct half of the full WTP plant electrical reactive load; one per 13.8kV bus, i.e., switchgear MVE-SWGR-87001A, MVE-SWGR-87001B, MVE-SWGR-87002A, & MVE-SWGR-87002B.

1. Advantage

a) This type of system is able to handle changing reactive loads in order to maintain a specified power factor within the step size (band) of an individual capacitor bank.

b) Comparably smaller required foot print as compared to a fixed capacitor system applied to each inductive load throughout a plant.

c) Less capital and maintenance cost than an automatic filter system (see section E below)

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2. Disadvantage

   a) This system may amplify harmonic voltages generated from non linear loads. See assumption IV.C.3.

   b) More capital and maintenance costs than a fixed capacitor bank

   c) More complicated to design and implement than a fixed capacitor bank

3. Cost

   The ROM TIC is going to be on the order of $1.3M (Att. #4)

4. Schedule

   Project Duration - 18 months from initiation of EPC&C contract. 5 months for engineering and procurement, 4 months for Fabrication and Delivery from award for the Automatic Power Correction unit. 6 months for Construction to install and 3 months for Startup to test and commission.

5. Recommendation

   A recommendation for a PFCS should not be made prior to completing a harmonic analysis study.

E. Active/Automatic PFCS Using Filter Banks

An automatic PFCS is made up of power monitoring relays, a control system, switching devices (breakers, contactors, etc.), and multiple banks of filters. Filter banks are automatically switched to maintain the desired power factor. This type of system can be designed to be interfaced with the electrical system at the service entrance, electrically below the utility metering point. In the case of the WTP, with four 13.8kV buses with load group A & B tie breakers and lower level automatic tie breakers; four (4) automatic power factor correction units would be expected. Each power factor correction unit will need to be sized to correct half of the full WTP plant electrical reactive load; one per 13.8kV bus, i.e., switchgear MVE-SWGR-87001A, MVE-SWGR-87001B, MVE-SWGR-87002A, & MVE-SWGR-87002B.

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1. Advantage

   a) This type of system is able to handle changing reactive loads in order to maintain a specified power factor within the step size (band) of an individual capacitor bank.

   b) Comparably smaller required foot print as compared to a fixed capacitor system applied to each inductive load throughout a plant.

   c) A partially tuned filter can be utilized for THD correction per IEEE 519, as well as power factor correction.

2. Disadvantage

   a) More costly then a capacitor bank PFCS

   b) Filters must be tuned to specific frequencies and loads requiring additional work. Changes in the type of loads and total load may require modification.

   c) Complicated design and implementation

3. Cost

   The ROM TIC is going to be on the order of $2.1M. (Att. #4)

4. Schedule

   Project Duration – 18 months from initiation of the EPC contract. 5 months for engineering and procurement, 4 months for Fabrication and Delivery from award for the Automatic Power Correction unit. 6 months for Construction to install and 3 months for Startup to test and commission.

5. Recommendation

   Based on assumption V.C.4, an automatic PFCS using filters would not be economical as compared to one using capacitors.

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It should also be noted that the Electrical Basis of Design (Ref. #15, Section 8.1.1.1) and Electrical Design Criteria (Ref. #16, Section 2.1.2) both call out IEEE 519 Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems as an implementing standard. Should the Harmonic analysis show noncompliance with IEEE 519 recommendations, the automatic filter can be utilized to address both power factor and harmonics. The WTP Harmonic Load Analysis is forecasted to be completed on December 30, 2010 (Ref. #12).

F. PFCS Cost-Benefit Analysis

The power factor penalty information is from BPA Transmission Services, 2010 Transmission and Ancillary Service Rate Schedules (Ref. #19). The capacitor bank and filter bank pricing information is from a budgetary quote from Northeast Power Systems Incorporated (Att. #1).

Power Factor penalty will be assessed at a rate of $0.28 per kVAR beyond a 97% pf (Ref. #19, page 86); However, the power factor penalty will only be assessed 61% of the time based on Low Load Hours (LLH) defined as 11pm to 6am Monday thru Saturday and all hours on Sunday (Ref. #19, page 101). i.e., 1-(66 hours/168 hours in a week) = 0.607 or ~ 61% of the time.

From Att. #4, the estimated ROM TIC for a capacitor bank is $1.3M and for a filter bank is $2.1M.

The fastest return on investment would occur with the WTP running at the worst possible power factor.

For the purposes of this estimate a lagging power factor of 80% will be used. Based on the current calculated lagging power factor of 91.6% (Ref. #1 Section 8.1.1), this is a conservative value to utilize. This will result in 25MVAR per month assessed with the BPA power factor penalty of $280 per MVAR or $6,995 per month (Att. #6); however, with BPA not assessing the power factor penalty for lagging power factors during the LLH (Ref. #19, page 101), which by definition represents 39% of the time, the monthly charge will be reduced to $4,267 per month or 61% of the gross power factor penalty. Not accounting for the rate of return on money or the operational maintenance cost of the PFCS, it would take approximately 25 years to obtain a return on investment for the capacitor bank PFCS and approximately 41 years for a filter bank PFCS. See Attachment 6 for Power Factor Correction Cost Benefit Analysis Estimate Worksheet; which also shows a range of results for varying percent electrical plant loading.

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Utilizing the current calculated lagging power factor of 91.6% (Ref. #1 Section 8.1.1), it would take approximately 56 years (Att. #7) to obtain a return on investment for the capacitor bank PFCS and approximately 93 years for a filter bank PFCS.

1. PFCS Recommendation

Based on the above analysis, this study does not recommend the utilization of a PFCS solely for avoidance of the power factor penalty as assessed by BPA. However, pending the results of the WTP Harmonic analysis, should a filter be required to meet the recommendations of IEEE 519, it may still be economical to install a filter bank that corrects WTP current waveforms per IEEE 519 and corrects the WTP power factor to 97%.

G. Power Factor Correction Interactions with 70MW (76.4MVA) Options

With assumption V.C.3, that the utility metering point is the A6 feeders to WTP, the power factor correction units would have to be physically interfaced with the WTP Building 87 MVE-SWGR-87001A&B and MVE-SWGR-87002A&B. None of the 70MW (76.4MVA) options presented in this study physically affect Building. 87, thus a PFCS could be implemented concurrently.

H. Power Factor Correction and Fifth Feeder

Power Factor Correction could be implemented in conjunction with the Fifth Feeder and using the existing 62MVA transformers. Assuming the Fifth Feeder was operating as an alternate source of power to MVE-SWGR-87003A&B and the PFCS was maintaining a 97% pf, then 60MW (62MVA) of power could be supplied from an existing transformer, with the additional 7MW of power supplied from the A8 Substation; for a total of 67MW (73.1MVA) of electrical power.

The total installed cost is estimated on the order of $6.8M. $5.5M estimated by BNI for Option 4 (Ref. #2), plus $1.3M for the power factor correction system (Att. #4)

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VIII. ACCEPTANCE CRITERIA

This section pertains only to the evaluation of the various design options to provide 70MW (76.4MVA) of power to the WTP.

A. Functionality

Can the option being reviewed provide the 70MW (76.4MVA) @ 91.6% lagging power factor (before any power factor correction) of power on a single electrical power source (one transformer/switchgear load group set operating normally) required by DOE in the commission of this study? This is a pass/fail criterion.

B. Reliability

For the purposes of this study, a double ended electrical line-up is considered the most reliable. 2 out of 3 operations are considered the next most reliable electrical line-up. The least reliable electrical line-up is a radial design.

C. Risk

This will be a comparative discussion between the current design requirements, of 100% plant operations with one out of two transformers failed.

D. Cost

A Total Installed Cost (capital, engineering, construction, & commissioning costs) including any demolition cost will be ranked from highest to lowest based on their TIC.

E. Final Recommendation

Of the options reviewed, the option that is recommended to DOE will be able to provide a minimum of 70MW (76.4MVA), will have the highest reliability for the most cost effective price. Cost risk will be factored into the selection process as well.

Schedule was excluded as a selection criterion, since the transformer procurement time is the schedule critical path, which is essentially the same for each option.

Should two different options be technically acceptable with the estimated cost being statistically the same, the option with the lowest cost risk will be selected.

The order of precedence, in the event that an option reviewed has a lower cost, but is less reliable, the more reliable option will be recommended.

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IX. METHOD OF ANALYSIS

A. WTP Load Flow Analysis

Will be evaluated against industry standards listed in this study.

B. Fifth Feeder Study

Will be evaluated against industry standards listed in this study.

C. WTP Power Factor Correction

A cost-benefit analysis will be performed to determine if it is cost effective to implement a PFCS based on the BPA power factor penalty rates.

D. Hanford 230kV Electrical Utility System

The Hanford 230kV electrical utility system SKM files that were provided for review at the time of this study were missing key electrical system component information that precluded the ability to perform the required system analysis (Ref. #25). However, as a compensatory means of answering the question, "Does the Hanford 230kV system have sufficient capacity to support the 70MW (76.4MVA) WTP electrical loads, the Hanford Site Projected Loads, and current Hanford site loads?" a preliminary analysis was performed on the available Hanford 230kV system based on the 230kV transmission line sizes.

E. Options to Provide a Minimum of 70MW (76.4MVA) of Electrical Power to the WTP

This section pertains only to the evaluation of the various design options to provide 70MW of power to the WTP. The option to address the TF projected loads is addressed in the Hanford 230kV Electrical Utility System.

1. Functionality

Can the option being reviewed provide the 70MW (76.4MVA) of power on a single electrical power source (one transformer/switchgear load group set operating normally) required by DOE in the commission of this study? This is a pass/fail criterion.

2. Reliability

A double ended electrical line-up is considered the most reliable. 2 out of 3 operation is considered the next most reliable electrical line-up. The least reliable electrical line-up is a radial design.

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3. Cost

A Total Installed Cost (capital, engineering, construction, & commissioning costs), including any demolition cost, will be ranked from highest to lowest based on their TIC.

F. Loss of Transformer Fan Cooling

For the purposes of this study IEEE Guide for Loading Mineral-Oil-Immersed Transformers, IEEE C57.91, will be consulted for maintaining transformer operation with reduced stage(s) of cooling capability. The transformer manufacturer should also be consulted prior to utilizing a transformer outside of its intended design conditions.

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X. HANFORD 230KV ELECTRICAL UTILITY SYSTEM

The Hanford 230kV electrical utility system SKM files that were provided for review at the time of this study were missing key electrical system component information that precluded the ability to perform the required system analysis.

As a compensatory means of answering the question, "Does the Hanford 230kV system have sufficient capacity to support the 70MW (76.4MVA) WTP electrical loads, the Hanford Site Projected Loads, and current Hanford site loads?" a preliminary analysis was performed on the available Hanford 230kV system information.

The following documents were used as a basis for the preliminary assessment:

- Electrical Hanford Plant High Voltage Lines, H-5-255, Rev 13 (Ref. #20)
- Electrical 230kV Single Line Switching Diagram, H-5-102, Rev 36 (Ref. #21)
- 230kV Impedance Diagram, H-6-13436 Rev 5 (Ref. #23)

Based on the information in these documents (maximum rated current = 673A based on Egret Transmission Cable rating) and the assumptions called out in section V.D of this study, it can be ascertained that the maximum Hanford 230kV system electrical capacity is approximately 268MVA.

With the projected Hanford 230kV system loading as follows:

- 70MW @ 91.6% pf (76.4MVA) projected WTP Electrical Loads
- 78MVA for the Hanford 230kV Baseline Case projected loads (Att. #11)
- 22MW (Att. #10) for the currently operating Hanford 230kV loads (A6, A7, & A8 Substations)

The resulting total projected Hanford 230kV loads is approximately 180MVA or 67% of the Hanford 230kV system capacity.

Only the A8 and A6 Substations are physically located in the approximate vicinity of the projected loads. Between these two substations, the existing maximum electrical capacity is 95MVA; half of the projected loading.

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It should also be pointed out that the 78MVA Hanford 230kV Baseline Case projected electrical loading is supporting the WTP Project. The entire 180MVA of projected loads will need to be supported by the Hanford 230kV electrical system at the same time. In a review meeting of this study, held on July 22, 2010 (Ref. #26); this issue was brought up. It was pointed out that the best option to address WTP's 70MW loading was not necessarily the best option to address the entire Hanford site electrical loads. In addition to this, EU stated that they would prefer not to impact the existing substations; since the A8 Substation had recently been upgraded and the A6 Substation had been built specifically for the WTP project and never been utilized. Based on this criterion, DOE-RL presented an option to expand the Hanford 230kV A6 Substation Expansion (See Figure #2). Below the dashed line is the existing A6 substation with the new substation shown above the dashed line.

This option is favorable for the following reasons.

- This option addresses the projected Hanford 230kV electrical load increases for the WTP project as well as the 200 Area electrical load increases supporting the WTP project.
- This option is the least likely to impact the WTP project schedule if provisions are made in the existing ductbank to interface the new substation circuits feeding the WTP. The WTP project can continue to utilize the existing A6 Substation (62MVA), based on the current calculated WTP electrical load demand (53MW or 58MVA); without operational load growth factors applied.
- This option could allow more time to pass (several years), if a delayed implementation of the second substation was chosen, to refine the TF waste handling process that are going to be utilized in support of the WTP, thus allowing more time to refine the required electrical load demand. This would allow for a more efficient sizing of the A6 expansion and thereby reducing lifetime operational costs of the new substation. Note: Delaying the implementation of the second substation would not technically meet the 70MW requirements of this study.
- This option could support the WTP electrical needs through project turnover to the TF Operator and potentially for several years of operations.
- The A6 expansion could be utilized for both the WTP operational load growth as well as the additional TF loads.

For the purpose of comparison to the other 9 options presented in this study to address only the WTP 70MW @ 91.6% pf electrical loading, the below analysis is provided.

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1. Functionality

   This option will provide the WTP and the TF Loads the same level of functionality as is currently designed for in the existing A6 Substation.

2. Reliability

   This option is essentially a 2 out of 4 configuration, which would be considered slightly lower in reliability as compared to a 1 out of 2 configuration.

3. Risk

   This option has the lowest level of risk of any options with regard to cost and schedule. There would be no impact to the WTP project, as long as the ductbank interface necessary to tie the expansion A6 substation feeders with two of the existing A6 Substation WTP feeder circuits was completed prior to energization of Building 87.

4. Cost

   ROM TIC = $20.2M (Att. #3 and Att. #4)

5. Schedule

   The transformers and switchgear are long lead items. The transformer has a 1 year turnaround time from the time of award. This would make the schedule for implementation from time of award of contract to be approximately 2 years.

6. Advantages

   Meets the 70MW (76.4MVA) electrical power delivery objective and does not impact the original operational intent of the double ended line-up that the A6 Substation was originally designed with.

   Allows for the greatest load capacity.

   This option will preserve the existing operations and WTP project contract agreements.

   Except for modification to 230kV bus and bus and transformer differential circuits and redirecting some tip circuits, does not require modification to A6 substation controls, 13.8kV systems, or the control bldg.

   New substation expansion will have enough capacity to accommodate waste feed and tank farm loads

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Maintains use of 3,000A switchgear inside existing A6 substation – no increase in bus capacity

Operational Interface is clean, follows established guidelines for interface control (TWRS; BPA)

Separation of ownership of hardware is clean

Follows established controls of the auxiliary equipment, such as 13.8kV feeder protection schemes and communication systems and interface is well understood and controlled.

Hanford SCADA system design and communications and operations will remain similar

Access to EU medium voltage equipment is limited to qualified Utility personnel

Agrees with current contract infrastructure services

Customer relays and protection schemes do not trip open the 230kV loop.

Configuration control maintained by the site utility.

Continued use of Utility existing lock and tag program.

No cost until WTP load growth approaches 62MVA

7. Disadvantages

This option also requires breaking into the existing WTP ductbank to interface with the new switchgear building ductbank and the installation of an additional building.

Will require new connections or changes in connection to WTP loads.

Additional discussion needed with BPA for any impacts to regional loads and BPA operations.

Note: It should be pointed out that a full electrical system study by the Hanford 230kV Utility Operator should be conducted to validate that the Hanford 230kV system can support this system change.

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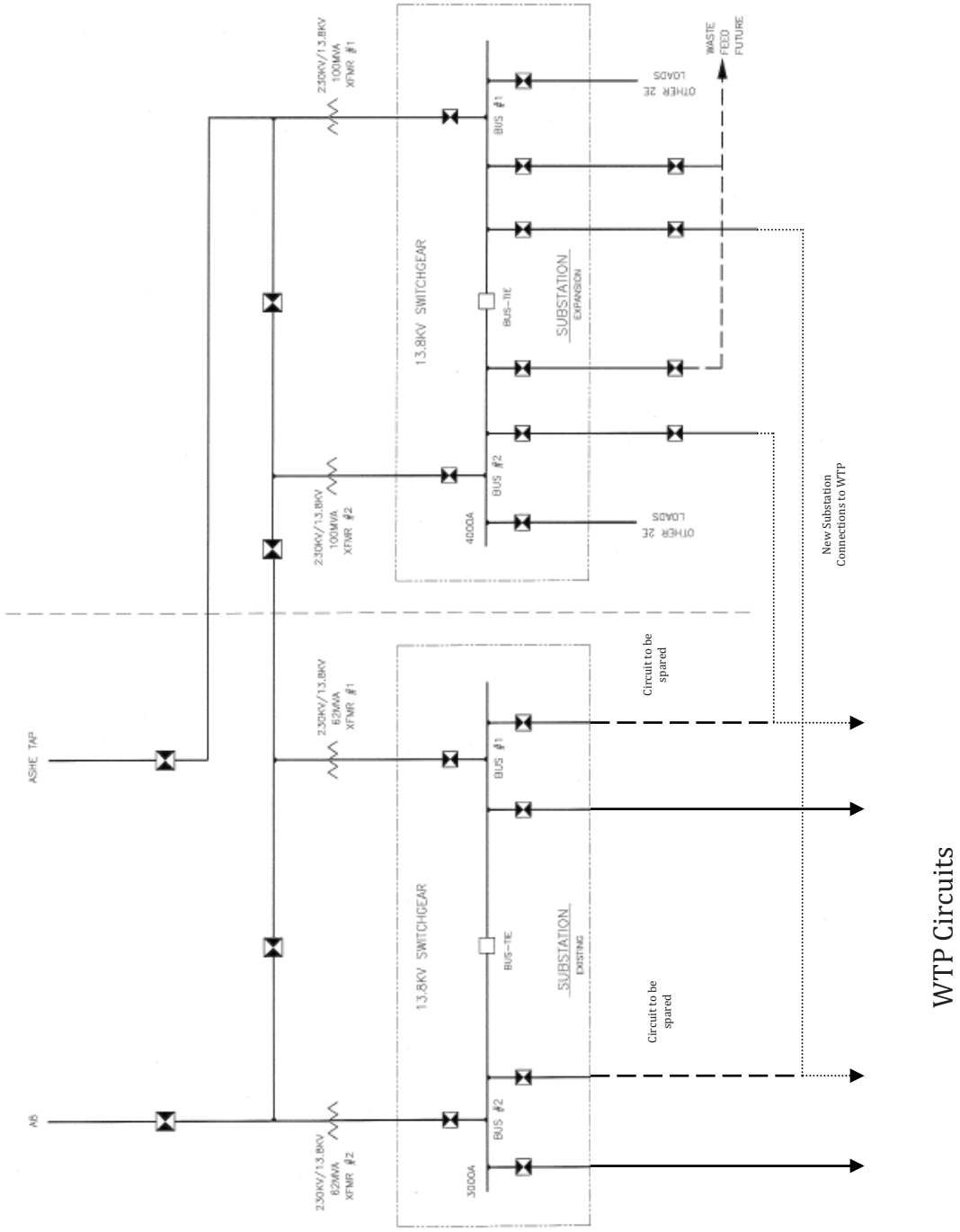
Figure #2 Hanford 230kV A6 Substation Expansion



XI. OPTIONS REVIEWED FOR PROVIDING A MINIMUM OF 70MW (76.4MVA) OF ELECTRICAL POWER TO THE WTP

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As of the present, the WTP 13.8kV switchgear in B87, the electrical service entrance for the WTP project, have not been energized from the A6 Substation, so no interruption in operations is assumed in the review of each option.

A. Current A6 Electrical Equipment Configuration

The A6 Substation is a standard double ended lineup, Main-Tie-Main configuration, with 3 feeder breakers per load group, one feeder per load group feeds building services with the other two feeders supporting the WTP. The primary 230kV network is a loop configuration with the Main-Tie-Mains normally closed. (Ref. #8)

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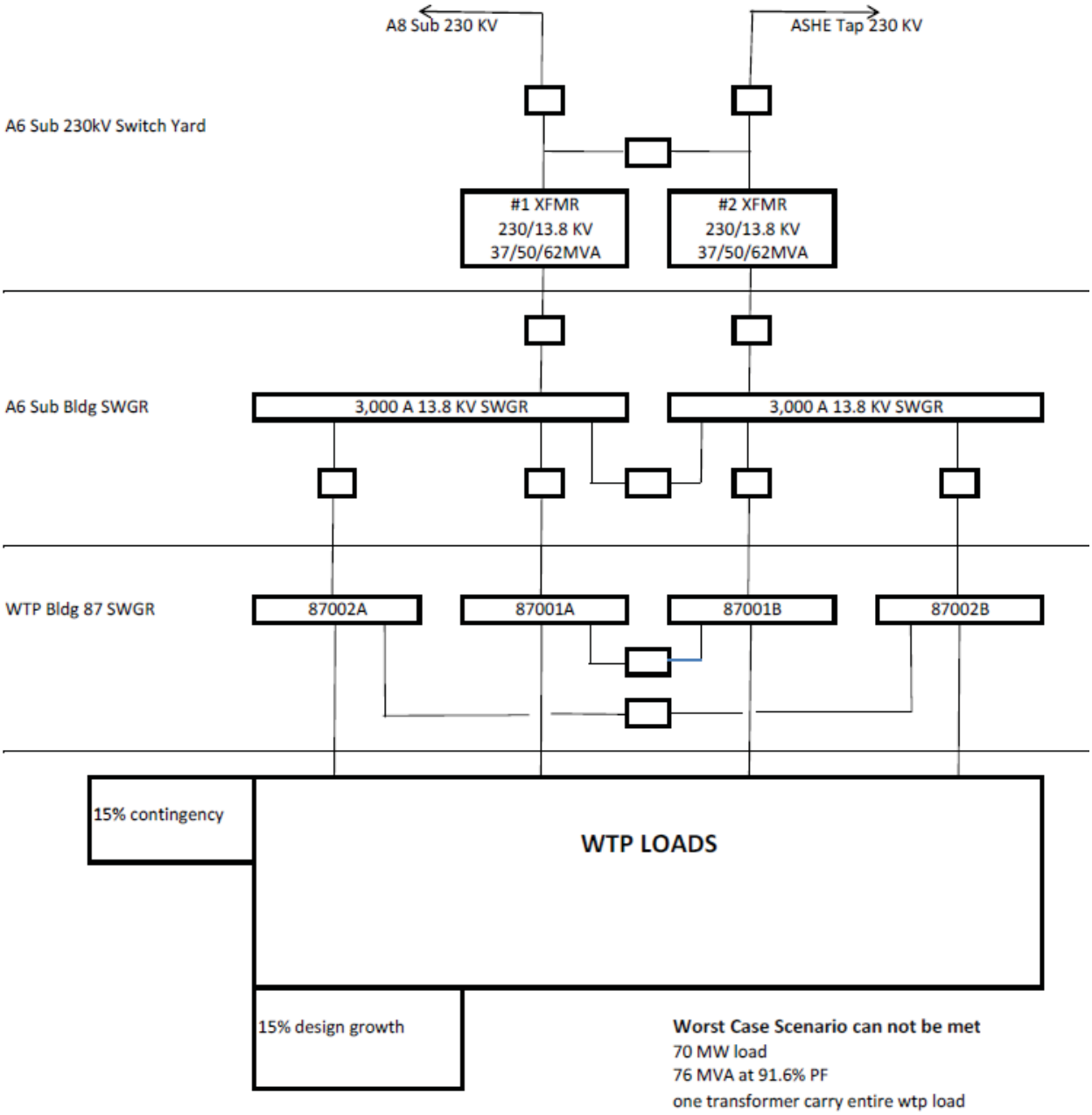
Figure #3 - 37/50/62MVA XFMRs and 3kA Swgr



EXISTING TWO 62 MVA TRANSFORMERS & 3,000 A BUS

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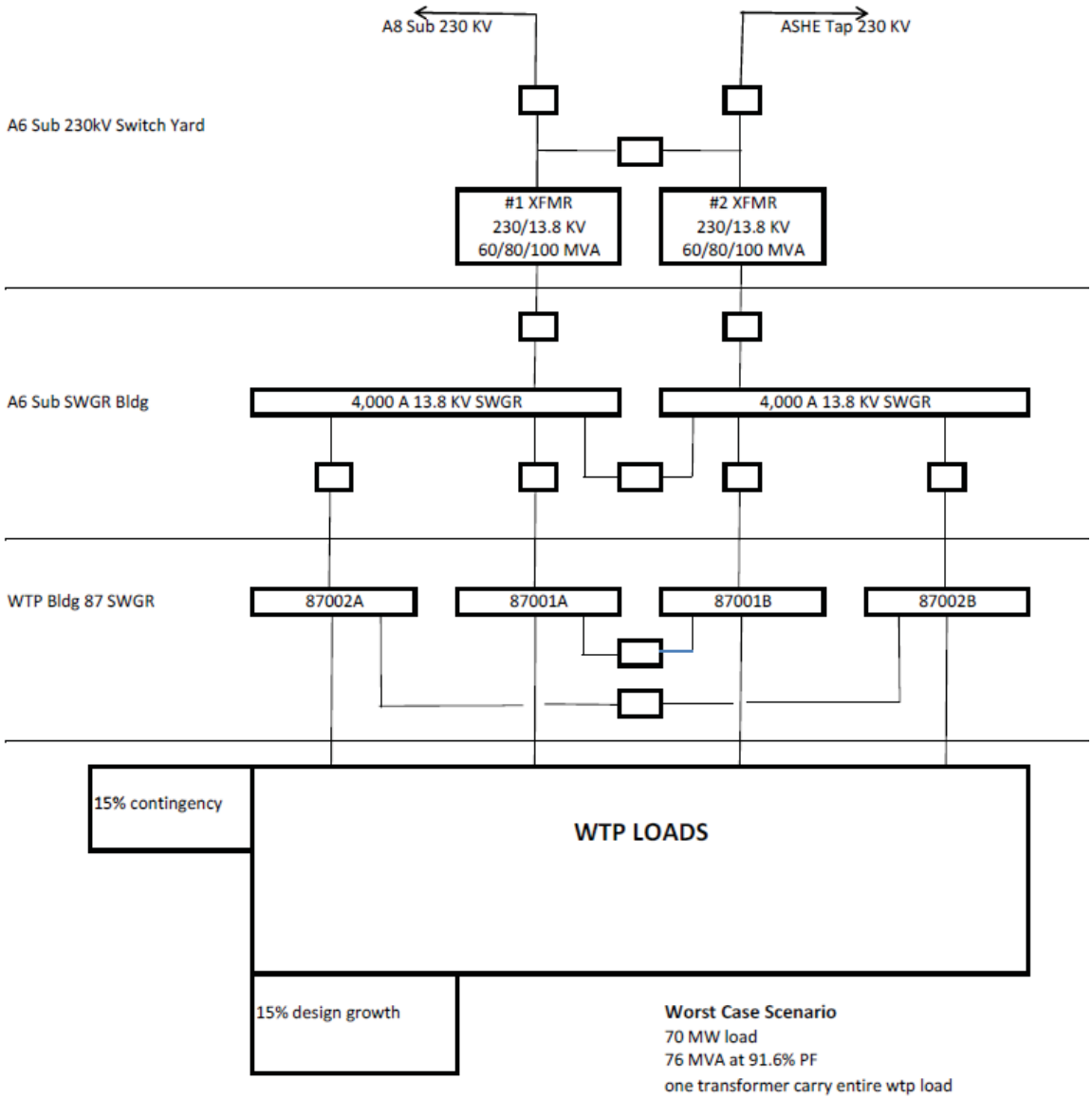
B. Option 1 – A6 Substation Electrical Equipment Upgrade

Figure #4 - 60/80/100MVA XFMRs, 2-4kA Swgr, and 1 Swgr Bldg



TWO 100 MVA TRANSFORMERS & 4,000 A BUS

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1. Functionality

   Option 1 will provide a maximum continuous average electrical power supply of 95MVA per transformer. Option 1 is limited to 95MVA, instead of the full 100MVA transformer rating, due to the limitation of the 4,000 amp rating of the 13.8kV switchgear and bus duct. This option meets the minimum power requirements of 70MW (76.4MVA) at the current calculated load pf of 91.6%.

2. Reliability

   Utilizing air insulated breakers, Option 1 maintains nearly (cooling fans required for 4,000A breaker) the same level of reliability of the existing design. Option 1 utilizes the same electrical configuration with no additional equipment. Note that dual cooling fans and fan failure alarms can be provided for the 4,000A breakers.

   Utilizing gas insulated breakers (no cooling fans required for 4,000A rating), Option 1 maintains the same level of reliability of the existing design. Option 1 utilizes the same electrical configuration with no additional equipment.

3. Risk

   This option has the same level of risk as compared to the current A6 Substation configuration.

4. Cost

   ROM TIC = $12.3M (Att. #3 and Att. #4)

5. Schedule

   The transformers and switchgear are long lead items. The transformer has a 1 year turnaround time from the time of award. This would make the schedule for implementation from time of award of contract to be approximately 2 years.

6. Advantages

   Meets the 70MW (76.4MVA) electrical power delivery objective and does not impact the original operational intent of the double ended line-up that the A6 Substation was originally design with.

   Single 100MVA transformer can carry the anticipated load with loss of one stage of cooling fans.

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Operational Interface is clean, follows established guidelines for interface control (TWRS; BPA)

Separation of ownership of hardware is clean

Follows established controls of the auxiliary equipment, such as protection schemes and communications systems and interface is well understood and controlled.

Hanford SCADA system design and communications and operation will remain similar.

Access to EU medium voltage equipment is limit to qualified Utility personnel.

Agrees with current contract infrastructure services

Customer relays and protection schemes do not trip open the 230kV loop.

Additional interface agreements not needed with BPA

Configuration control of the 230kV system is maintained by the site utility.

Continued use of the Utility existing lock and tag program

Does not require reconnection of WTP loads to new busses if fault duty is not an issue.

Will not require modification to the 230kV system

This option will preserve the existing operations and WTP project contract agreements.

7. Disadvantages

The 4,000 Amp switchgear are not standard pieces of equipment and the 4,000 amp main breakers, that will be required, are <u>specially designed with redundant fans to cool the main breakers</u>.

Transformer pads and oil containment system will have to be modified, rebuilt.

Performance of operations and maintenance functions may not allow use of established Site Utilities programs and may require training and procedures preparation for 100MVA transformers and 4,000A switchgear.

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Additionally, because of the larger transformers, a higher available fault current is possible. The short circuit study will have to be run to identify an acceptable impedance (%Z) of the new transformer such that the 28kA (rms) rating of the existing WTP switchgear is not exceeded.

A test calculation was performed to verify viability of procuring the 60/80/100MVA transformers with an appropriate %Z. By no means should this calculation be used for purchase of these transformers. A short circuit analysis needs to be performed to account for WTP motor contributions in the selection of the transformer %Z.

Givens:

Vprimary = 230,000V

Vsecondary = 13,800V

Is.c.primary = 10722.7A(rms) (Ref. #1, Appendix 11.1)

Is.c.secondary = 28,000A(rms) WTP switchgear maximum fault current rating (Ref. #13)

MVAxfmr = 60MVA self cooled rating of Option 1 transformers

Equations Used:

Equation 1:

$$f = \text{Is.c.primary} * \text{Vprimary} * \text{sqrt}(3)(\%Z)/(100 * \text{MVAxfmr})$$

Equation 2:

$$M = 1/(1 + f)$$

Equation 3:

$$\text{Is.c.secondary} = \frac{\text{Vprimary}}{\text{Vsecondary}} * M * \text{Is.c.primary}$$

Therefore

$$M = \text{Is.c.secondary} * \text{Vsecondary}/(\text{Vprimary} * \text{Is.c.primary})$$

Substituting 1/(1+f) for M and solve for f

$$f = \frac{1}{\text{Is.c.secondary} * \frac{\text{Vsecondary}}{\text{Vprimary} * \text{Is.c.primary}}} - 1$$

Substituting equation 1 for f and solving for %Z results in the minimum transformer impedance necessary not to exceed 28kA (rms).

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$$\%Z = 100{,}000 * kVAxfmr * \left(\frac{Is.c.primary * Vprimary}{Is.c.secondary * Vsecondary} - 1\right)/(Is.c.primary * Vprimary * sqrt(3))$$

Solving this equation

$$\%Z = 100{,}000 * 60{,}000 * \left(\frac{10{,}722.7 * 230{,}000}{28{,}000 * 13800} - 1\right)/(10{,}722.7 * 230{,}000 * 1.73)$$

$$\%Z = 7.56$$

Again, this calculation assumes no contribution to fault current from WTP motor loads, which is not the case. A detailed short circuit analysis must be performed to determine the required transformer impedance (%Z), or other possible modifications associated with the new gear, to ensure the short circuit rating of the WTP electrical equipment is not exceeded. Assuming that there is not a substantial WTP contribution to the fault current, this calculation shows that it is commercially viable to procure a transformer with the required impedance to meet the 28kA rms rating of the WTP medium voltage switchgear.

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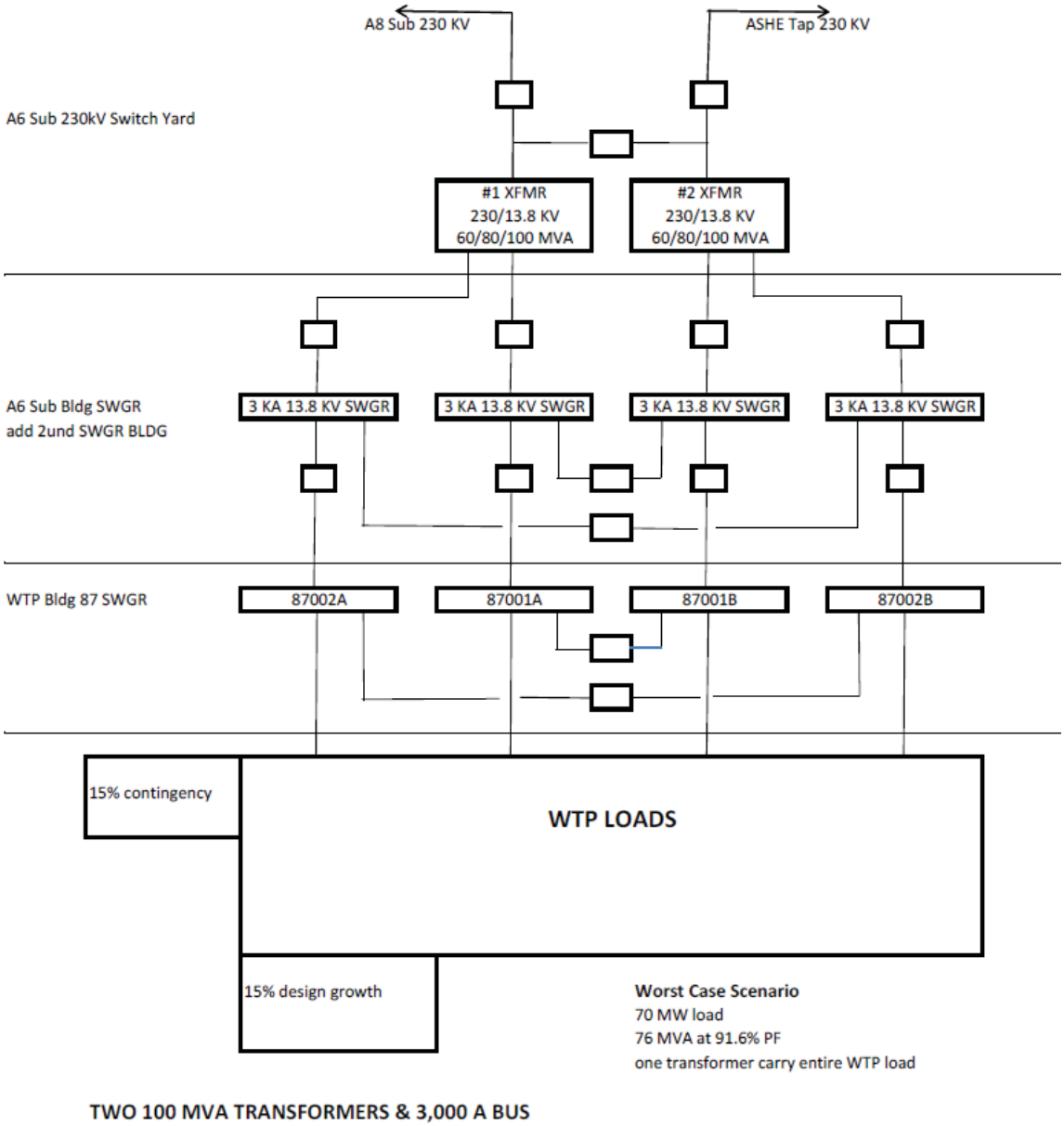
C. Option 2 – A6 Substation Transformer Upgrade (3-winding), 2 New Switchgear, and Switchgear Building.

Note: Transformer primary winding rating shown

Figure #5

2-60/80/100MVA 3 Winding XFMRs with the Secondary and Tertiary Windings Rated at 50%MVA Each, 4-3kA Swgr, and 2 Swgr Bldgs



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1. Functionality

   Option 2 will provide a maximum continuous average electrical power supply of 100MVA per transformer. Option 2 is limited to the 100MVA rating of the second stage of transformer fan cooling. This option meets the minimum power requirements of 70MW (76.4MVA) at the current calculated load pf of 91.6%.

2. Reliability

   Option 2 has a slightly lower level of reliability as compared to the existing design, due to the increased number of components. However, this is viewed as a minimal decrease in overall system reliability.

3. Cost

   ROM TIC = $18.4M (Att. #3 and Att. #4)

4. Risk

   This option has a higher level of risk as compared to the current A6 Substation configuration, due to the two extra switchgear necessary to implement this option.

5. Schedule

   The transformers and switchgear are long lead items. The transformer has a 1 year turnaround time from the time of award. This would make the schedule for implementation from time of award of contract to be approximately 2 years.

6. Advantages

   Meets the 70MW (76.4MVA) electrical power delivery objective and does not impact the original operational intent of the double ended line-up that the A6 Substation was originally design with.

   This option will preserve the existing operations and WTP project contract agreements.

7. Disadvantages

   Option 2 requires the addition of a second switchgear building, two more bus ducts, and two more switchgear.

   This option also requires breaking into the existing duct bank to interface with the new switchgear building duct bank.

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Refer to Option 1 Disadvantages for short circuit capacity concerns regarding transformer impedances necessary to maintain fault currents under 28kA (rms)

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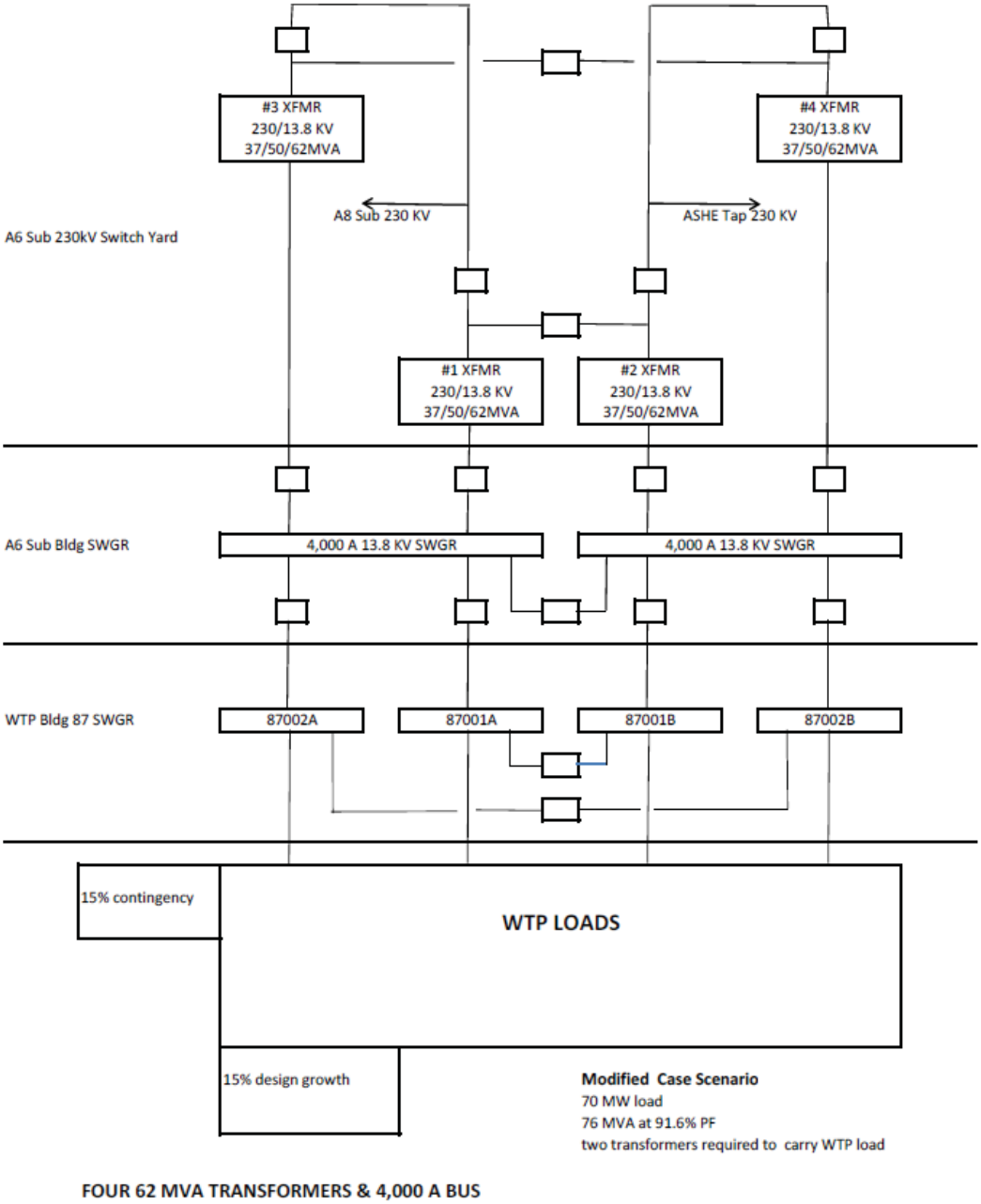
D. Option 3 – Partial Implementation of Future Expansion of A6 Substation

Figure #6 4-37/50/62MVA XFMRs, 2-4kA Swgr, and 1 Swgr Bldg.



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1. Functionality

   Option 3 will provide a maximum continuous average electrical power supply of 95MVA. Option 3 is limited to 95MVA, instead of the full combined transformer rating of 124MVA, due to the limitation of the 4,000 amp rating of the 13.8kV switchgear. This meets the minimum power requirements of 70MW (76.4MVA) at the current calculated load pf of 91.6%.

2. Reliability

   Option 3 has a lower level of reliability as compared to the existing design, due to the increased number of components.

3. Risk

   This option has a higher level of risk as compared to the current A6 Substation configuration, due to the two extra transformers necessary to implement this option.

4. Cost

   There is insufficient space in the existing A6 switchgear building to implement this option. This would require an additional switchgear building, which based on Option 2 estimated pricing, makes this option economically impractical as compared to other options presented in this study. No further review was made of this option.

5. Schedule

   Not provided due to the economic non viability of this option.

6. Advantages

   Not provided due to the economic non viability of this option.

7. Disadvantages

   Not provided due to the economic non viability of this option.

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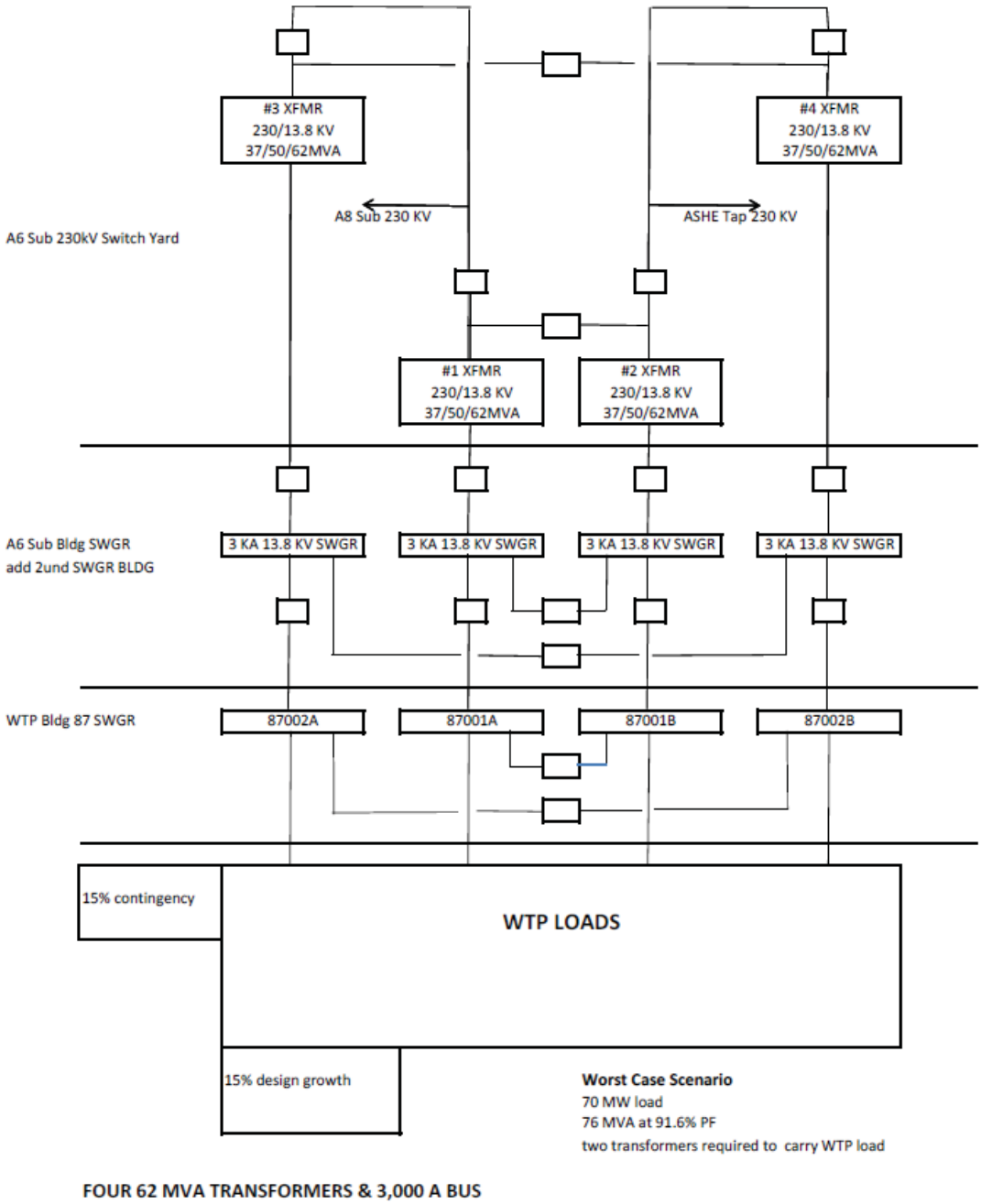
E. Option 4 – Implementation of Future Expansion Portion of A6 Substation

Figure #7 4-37/50/62MVA Xfmrs, 4-3kA Swgr, and a 2nd Swgr bldg.



FOUR 62 MVA TRANSFORMERS & 3,000 A BUS

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1. Functionality

   Option 4 will provide a maximum continuous average electrical power supply of 124MVA or 62MVA per transformer. Option 4 is limited to the 62MVA rating of the second stage of transformer fan cooling per transformer. This meets the minimum power requirements of 70MW (76.4MVA) at the current calculated load pf of 91.6% with the condition that 2 of the 4 are operational.

2. Reliability

   Option 4 has a slightly lower level of reliability as compared to the existing design, due to the increased number of components. However, greater power source diversity is achieved with this option, i.e., in the event of the loss of one switchgear building, plant operations could continue on the remaining two 62MVA transformers.

3. Risk

   This option has a higher level of risk as compared to the current A6 Substation configuration, due to the two extra switchgear and two extra transformers necessary to implement this option.

4. Cost

   ROM TIC = $17.5M (Att. #3 and Att. #4)

5. Schedule

   The transformers and switchgear are long lead items. The transformer has a 1 year turnaround time from the time of award. This would make the schedule for implementation from time of award of contract to be approximately 2 years.

6. Advantages

   Meets the 70MW (76.4MVA) electrical power delivery objective and does not impact the original operational intent of the double ended line-up that the A6 Substation was originally designed with.

   Adds greater power source diversity above each of the other options, including the current design, and allows for the greatest load capacity.

   Procuring the two new transformers, identical to the existing transformers, maintains the same level of fault current as the existing design.

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This option will preserve the existing operations and WTP project contract agreements.

7. Disadvantages

Option 4 implements the future expansion as shown on the original design drawings; as such it is nearly doubling the existing substation capacity as well as the amount of materials and equipment.

This option also requires breaking into the existing WTP ductbank to interface with the new switchgear building ductbank and the installation of an additional building.

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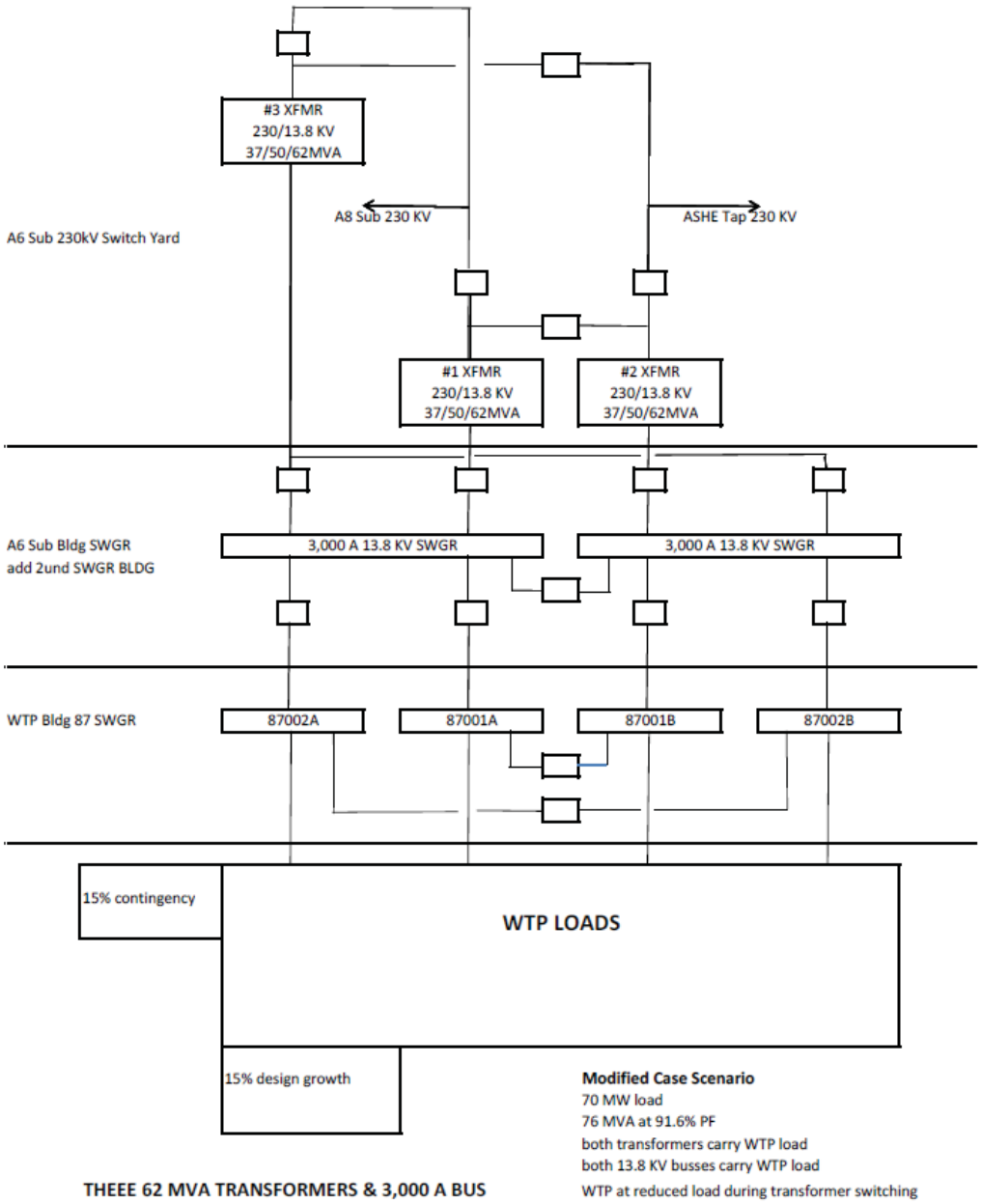
F. Option 5 – Swing Bus

Figure #8 Swing Bus



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1. Functionality

   This option utilizes a swing bus to maintain two transformers in operation, with only minimal transition time necessary to transfer to the swing transformer in the event of the loss of either of the normal power feeders. This option does not technically meet the minimum of 70MW (76.4MVA) operating on one out of two transformers, as required by the scope of this study. However, this option meets the intent of this study by maintaining 2 out of 3 transformer operations. In other words, with 2 out of 3 transformer operation 124MVA can be supplied to the WTP.

2. Reliability

   The reliability is reduced slightly due to the additional transformer and associated components necessary to implement a 2 out of 3 transformer operation.

3. Risk

   This option has a slightly higher level of risk, as compared to the current A6 Substation configuration, due to the extra transformer and two main breakers necessary to implement this option.

4. Cost

   ROM TIC = $12.6M (Att. #3 and Att. #4)

   EU Option #1 and #1A are within the cost estimate accuracy of this study's presented option, thus an additional cost estimate was not provided for these EU options.

5. Advantages

   Assuming the swing transformer is procured with identical impedance as the existing transformers and the transformers are never aligned in parallel, there would be no change to the available fault current.

   This option will preserve the existing operations and WTP project contract agreements.

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6. Disadvantages

Due to the implementation of ATSs on the WTP, operational controls would have to be put in place to monitor the A6 transformer loading. Upon loss of one of the two operating A6 transformers, the WTP ATSs would initiate transfers to the remaining power source. Should the electrical loads be restarted when the electric plant is aligned to the alternate power source, the remaining transformer could be overloaded; even though the swing transformer was brought on line.

This option may require the WTP ATSs to be disabled to prevent the automatic transfer from occurring during the time it takes to put the swing bus transformer in service.

Note 1: During the review of an earlier revision to this study, EU provided 2 additional variations of this option along with advantages and disadvantages (Ref. #26 EU Option #1 and Option #1A).

EU Option #1 attempts to eliminate the need for a second switchgear building necessary to implement this option by relocating the two additional main breakers required to implement a swing bus into an outdoor rated enclosure and bring cables directly into the existing switchgear. This would require a detailed review of the size of expansion sections necessary on both existing switchgear and the available clear working space in the substation switchgear building to determine if this variation of Option 5 is viable. Based on a walk down of the A6 substation switchgear building, this does not appear to be viable.

Note 2: EU Option #1A is an expansion of the existing A6 switchgear building in order to fit the additional main breakers. It is the opinion of this study that due to the necessary resizing of the substation support equipment (HVAC, Fire Suppression, Control Cabinets, etc.) that economically, this will be essentially the same as Option 5.

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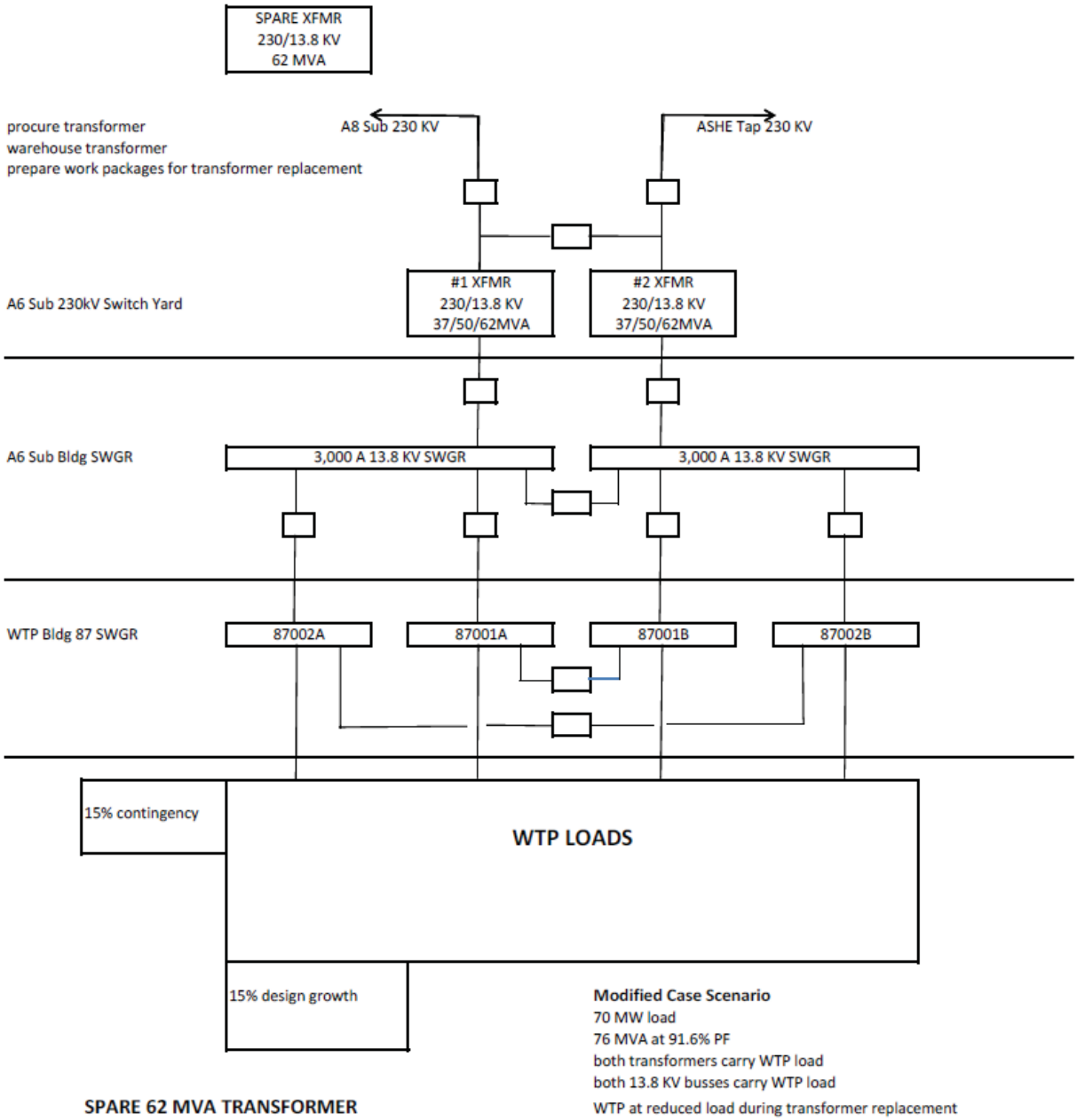
G. Option 6 – Warehoused Spare

Figure #9 Warehoused Spare



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1. Functionality

The option of a spare transformer physically stored per manufacturer recommendations, with operational work permits and procedures in place to change out a failed transformer. The intent of this option is to limit the amount of time that the WTP facility would be operating at reduced capacity on a single transformer, limited to 62MVA of electrical power. This option does not meet the 70MW (76.4MVA) requirement.

2. Reliability

This option does not change the reliability of the existing design, it only minimizes the time required to change out a failed transformer.

3. Risk

This option has a higher risk then the other options reviewed; however, this option capitalizes on the low probability of a transformer failure and mitigates the risk by eliminating the procurement cycle (up to a year) to obtain a replacement transformer. Additionally, steps can be taken to minimize the time necessary for installation as well.

4. Cost

Capital Cost = $1.5M (Att. #3 and Att. #4)

There would be additional storage costs.

5. Advantages

This option is substantially more economical than any other option reviewed in this study.

Minimizes the reduced operational period of the plant to approximately a month or less, assuming work processes and work permits were pre-prepared for this event. Given the year turnaround time on the procurement of this type of transformer, this is a substantial improvement.

This option will preserve the existing operations and WTP project contract agreements.

6. Disadvantages

This option only allows a maximum of 62MVA of power available for plant operations during transformer maintenance or replacement.

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This option only discusses a failed transformer, however there are other electric components that could fail, i.e., switchgear, bus duct, 230kV breaker, etc. that are also long lead items. Having warehoused spares could address these items as well.

According to the Hanford 230kV Electric Utility, currently there are no warehouse spares for bus duct, 230kV breakers or switchgear. There is a spare 13.8kV feeder breaker.

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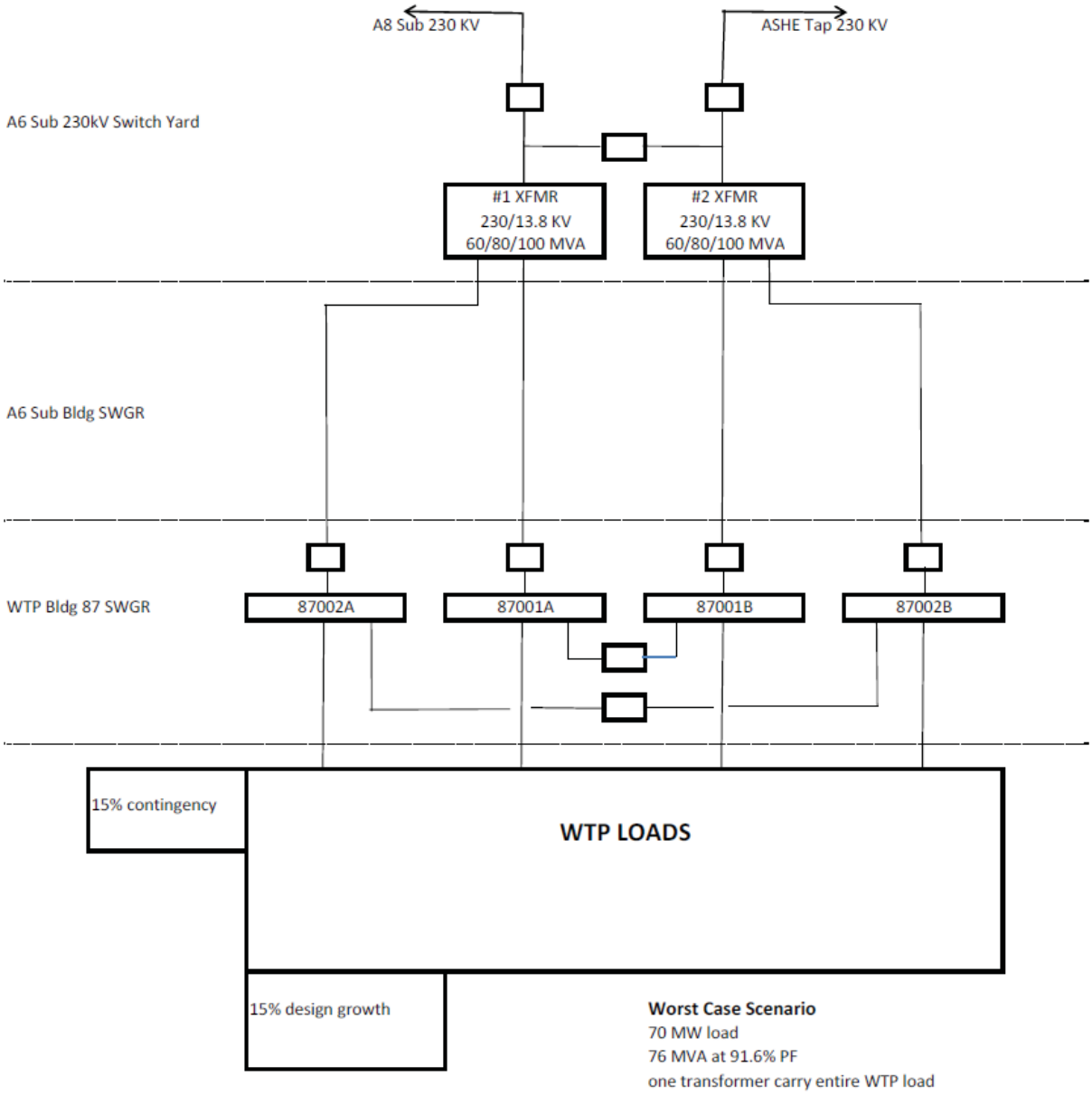
H. Option 7 – Eliminate the A6 Switchgear (Direct Power Feed from the A6 Xfmrs to Bldg 87)

This option would require contract changes to the WTP project, the Hanford Electric Utility Operator, and the TF Operations Contract.

Note: Transformer primary winding rating shown

Figure #10 2-60/80/100MVA 3 Winding XFMRs with the Secondary and Tertiary Windings Rated at 50% of the MVA XFMR Rating with 4 Direct Feeds to B87



TWO 100 MVA TRANSFORMERS & DIRECT FEED TO BLDG 87 SWGR

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1. Functionality

   Option 7 will provide a maximum continuous average electrical power supply of 95.6MVA per transformer. Option 7 is limited to the 2,000 Amp rating of the WTP 13.8kV switchgear. This meets the minimum power requirements of 70MW (76.4MVA) at the current calculated load pf of 91.6%.

2. Reliability

   Option 7 has a higher level of reliability as compared to the existing design, due to the decreased number of components. However, this is viewed as a minimal increase in overall system reliability.

3. Cost

   ROM TIC = $10.5M (Att. #3 and Att. #4)

   It should be noted that the above cost estimate does not include the cost of the required contract changes to the Hanford Electrical Utility, the WTP Project, or the TF Operations Contract. Additionally, this cost estimate does not include the cost of updating the WTP safety basis documents that would be necessary for implementing this change.

4. Schedule

   The transformers are long lead items. The transformer has a 1 year turnaround time from the time of award. This would make the schedule for implementation from time of award of contract to be approximately 2 years.

   The above schedule does not address the time necessary to modify the existing contracts that would be required to implement this option.

5. Advantages

   Option 7 meets the 70MW (76.4MVA) electrical power delivery objective of this study. This option also minimizes the number of electrical equipment required to provide power to the WTP, thus minimizing the maintenance cost.

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6. Disadvantages

This option will require the shared control of the WTP switchgear, with the Hanford 230kV system operator. The 4 main breakers on MVE-SWGR-87001A, 1B, 2A, & 2B would be the point of interface and the utility metering point. Additionally, these switchgears would have to be modified for the relaying necessary to protect the A6 Substation transformers.

A contract change would be required for the WTP to implement the necessary modifications to the switchgear in B87 and the WTP contractual documents (ICD-11, PSAR, BOD, etc.) would have to be updated with the change in the point of interface and clarify the power source changes for the B87 Switchgear Building.

With the elimination of the switchgear in the A6 Substation, two independent 75kVA, 208/120 V, building service power supplies will need to be provided from B87.

It should also be noted that both the WTP project and the Electrical Utility reiterated these same disadvantages in their review of this option, as opposed to the preferred configuration of Option 1.

Refer to Option 1 Disadvantages for short circuit capacity concerns regarding transformer impedances necessary to maintain fault currents under 28kA (rms)

Note: This option is not considered viable by EU. Ref. #26 for EU's specific advantages and disadvantages for this option.

I. Option 8 – Remove the Requirement of 100% Electrical Load Operations on One Transformer

The idea of this option is to allow the 100% use of both transformers during normal operation. This was an option that was addressed during the development of this study as well, but was disregarded early on primarily due to not meeting the 100% redundant power source requirement of this study.

J. Option 9 – Existing A6 Substation Configuration in Conjunction with the Fifth Feeder and Power Factor Correction

This option was reviewed and discussed earlier in the study under PFCS. See section VII.H

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K. Option 10 – Hanford 230kV A6 Substation Expansion

See Section X of this study for details.

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XII. LOSS OF TRANSFORMER FAN COOLING

Should a transformer be required to be operated while a stage(s) of cooling is not operable, two items should be consulted; first, the transformer manufacturer's recommendations, secondly, IEEE C57.91 Appendix H. Specifically, section H.3 states,

> *"For triple rated forced-air, forced-oil-cooled transformers with all or part of the cooling inoperative use the nameplate rating based on the full stage of cooling remaining in operation, or if less than a full stage of fan and pump cooling is operative, use the self-cooled (OA) rating. For loss of either fans or pumps on a stage of cooling, use the rating which pertains to total loss of that stage of cooling."*

In other words, for the case of a 60/80/100MVA ONAN/ONAF/ONAF rated transformer, the loss of single stage of cooling reduces the maximum transformer rating to 80MVA. Loss of both stages of fan cooling reduces the maximum transformer rating to 60MVA.

Utilizing a 60/80/100MVA transformer to supply 70MW (76.4MVA) at 91.6% power factor to the WTP on a single A6 transformer and a single stage of fan cooling was lost; 100% plant operations could be sustained indefinitely.

If both stages of fan cooling were lost while the WTP was operating on a single A6 transformer (i.e., 3 off-normal conditions simultaneously), a choice would have to be made.

1. To operate the WTP at reduced electrical loading, not to exceed 60MVA.

2. To consult the manufactures for recommended operations and to implement IEEE C57.91 section 9.5 Long Time Emergency Loading or section 9.6 Short Time Emergency Loading; whichever is appropriate.

    a) Section 9.5 Long Time Emergency Loading states in part,

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> *"Long-time emergency loading defines a condition wherein a power transformer is so loaded that its hottest-spot temperature is in the temperature range of 120°C–140°C. The characteristics of this type of loading are one long-time outage of a transmission system element, two or three occurrences over the normal life-time of the transformer each occurrence may last several months, and the risk is greater than planned loading beyond nameplate rating."*

b) Section 9.6 Short Time Emergency Loading states in part,

> *"Short-time emergency loading defines a loading condition wherein a transformer is so loaded that its hottest-spot temperature is as high as 180 °C for a short time. The characteristics of this type of loading are a series of unlikely conditions on the transmission system (second or third contingency), one or two occurrences over the normal lifetime of the transformer, and the risk is greater than for long-time emergency loading."*

During normal plant operation, approximately half of the 76.4MVA will be split (approximately 38.2MVA each) between the two A6 Substation transformers. Thus, during normal plant operations fan cooling will not be required and the self cooled rating of 60MVA would be adequate. For emergency loading to be required, three contingencies would be needed: first a single-ended operation, and then the loss of both stages of fan cooling.

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XIII. RESULTS/RECOMMENDATIONS

A. Power System Load Flow Analysis

The methodology described and utilized in the WTP Load Flow Analysis are consistent with IEEE 399 Recommended Practice for Industrial and Commercial Power Systems Analysis for the overall development of the calculation. Additionally, the calculation implements the recommendations of IEEE 141, Recommended Practice for Electric Power Distribution for Industrial Plants; among other appropriate industry codes and standards.

However, the WTP Load Flow Analysis, appears to have overstated the reactive load. This is due to bounding power factor values used for the lumped loads and possibly for Variable Frequency Drives (VFD). The WTP Load Flow Analysis did not give the basis for the power factor chosen. Additionally, the WTP Load Flow Analysis did not indicate the type of VFD utilized. A higher power factor will not impact the total MW load, but would reduce the MVAR loading; thereby reducing the total MVA loading of the WTP. This being said and ignoring the need for an operational load, the resultant raw (no design growth or contingency factor) maximum demand load of 50.498MW @ pf of 91.6% (55.1MVA) is reasonable; based on the information available for review.

This study recommends, based on the current A6 Substation configuration, that Interface Control Document for Electricity (ICD-11) be revised to reword the first paragraph of section 1.4.2 to modify the requirements for future margin, as follows,

> *"The maximum average operational power for the WTP is limited to a rating of 62MVA. For the purpose of design, a 30% operational growth margin shall be maintained to the point of Title III complete for calculating the maximum average electrical power utilized for WTP facility operations. If electrical losses are not accounted for in the software utilized to calculate the maximum average operational electrical power requirements an additional 5% electrical loss margin shall be included."*

This recommendation is based on DOE's direction to BNI in CCN 194415 (Ref. #7) and on industry standards, IEEE 141, section 2.4.1.4 Forecasting and Planning, for projected load growth of an operational facility with a projected 40 year life span.

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Design Growth and Contingency factors are utilized by design agencies to ensure that they meet client specified operational margins as recommended above. At the point of Title III design complete, these factors should no longer exist and the calculated electrical design load plus the operational growth margin should not exceed the clients' specified maximum average operational power available for project operations.

This study also recommends that ICD-11 should specify electrical design or operational power limitations in terms of Apparent Power (MVA or kVA) or to specify power limitations in terms of Real Power (MW) with a minimum power factor. As an example, based on the current ICD-11 wording in Table 1, item 4, which states,

> *"Consume up to 55MW "operations" power at the defined interface point."*

It is feasible to exceed the existing A6 Substation transformer ratings of 62MVA should the WTP electrical loads operate at 55MW with a power factor of less than 88.7%. Yet, ICD-11 does not mention any requirement for maintaining a minimum power factor.

This same issue exists within ICD-11 for the 7MW of temporary construction power from the A8 Substation.

B. Fifth Feeder Study

In terms of the scope of the Fifth Feeder Study (Ref. #2), assuming the Fifth Feeder as an alternate line-up with the A6 Substation as the normal source of power, this study concurs with BNI assessment and recommendation for Option 4.

As the Fifth Feeder Study pertains to the scope of this study, to achieve 70MW (76.4MVA) of electrical power for the WTP during the loss of one of the A6 Substation power feeds, none of the Fifth Feeder Study options meet this requirement. The Fifth Feeder is not recommended as a means to supply a minimum of 70MW (76.4MVA) of electrical power to the WTP as a standalone option or in conjunction with any other option presented in this study.

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However, it should be noted that in terms of a standby power source for the WTP project standby loads, the BNI estimated $5.5M for Fifth Feeder Study Option 4 is a cost effective alternative in terms of achieving 7MW (7.6MVA) of electrical power versus the utilization of standby diesel generators. In other words, should additional standby loads be required to be supported, i.e., the HLW and LAW melters, the Fifth Feeder would be a cost effective method to do so. It should also be understood that implementing the Fifth Feeder as a standby power source, still does not protect the WTP standby loads from a loss of both BPA 230kV power sources.

C. Power Factor Correction

Power factor correction can be implemented with any of the options reviewed in this study. However, it is not recommended to install a PFCS solely for the purposes of power factor correction. BPA currently does not assess a power factor penalty against the Hanford 230kV system. However, should BPA decide to assess the penalty against the Hanford 230kV system based on BPA Transmission Services, 2010 Transmission and Ancillary Services Rate Schedule (Ref. #19) this study still does not recommend implementation of a PFCS solely for the purpose of power factor penalty avoidance.

Two items should be noted:

1. A detailed harmonic analysis must be performed prior to implementation of a PFCS due to resonance that may occur between the PFCS and the reactive loads.
2. IEEE 519 is called out in both the Basis of Design (BOD) (Ref. 15, section 8.1) and the Electrical Design Criteria (Ref. #16 Section 2.1.2). IEEE 519 recommends current distortion limits resulting from loads such as Variable Frequency Drives (VFD), Uninterruptible Power Supplies (UPS). Depending on the results of the harmonic analysis of the WTP loads, a filter bank PFCS may be required. The WTP project is scheduled to complete the electrical load harmonic analysis in December of 2010 (Ref. #12).

Upon completion of the WTP electrical load harmonic analysis, should a filter bank be required to comply with the recommendations of IEEE 519, both harmonics and power factor correction can be addressed. The analysis necessary to perform this type of design is a specialty and is usually performed by the filter bank vendor on an operating plant; due to the risk of damage to both the filter bank and plant reactive loads.

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D. Hanford 230kV Electrical Utility System

The Hanford 230kV electrical utility system SKM files that were provided for review at the time of this study were missing key electrical system component information that precluded the ability to perform the required system analysis.

As a compensatory means of answering the question, "Does the Hanford 230kV system have sufficient capacity to support the 70MW (76.4MVA) WTP electrical loads, the Hanford Site Projected Loads, and current Hanford site loads?" a preliminary analysis was performed on the available Hanford 230kV system information.

Based on the preliminary analysis completed by this study, the Hanford 230kV system capacity is approximately 268MVA.

Based on the prior statement, no modifications to the 230kV system would be required in order to deliver 70MW (15MW more than what is currently allocated) at 91.6% pf (76.4MVA) to WTP as was contracted in this study; pending further evaluation and concurrence by BPA.

The Hanford projected electrical load is approximately 180MVA or 67% of the Hanford 230kV system capacity.

Since nearly all of the Hanford 230kV system projected electrical loading is either directly or indirectly supporting the WTP. It is the recommendation of this study that a solution addressing the projected Hanford 230kV system load growth be considered in place of the narrow scope to evaluate options that provide 70MW @ 91.6% pf to the WTP contracted in this study.

The Hanford 230kV A6 Substation Expansion option presented by DOE-RL in the review meeting (Ref. #26) for this study and presented in this study, satisfactorily addresses the specific WTP project present and future project electrical demands as well as the other 200 Area electrical loads that are presently being developed to support the WTP project. Since this option addresses both the criteria outlined in the commission of this study for the WTP electrical load demands as well as the projected electrical load demands of the Hanford site 200 Area, is the overall recommended option of this study.

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E. Recommended Option for Providing a Minimum of 70MW (76.4MVA) of Electrical Power to the WTP

The recommendations made in the prior section, Hanford 230kV Electrical Utility System, should be considered by DOE prior to the recommendations of this section of the study. The recommendation of this section is solely to comply with the original scope of the contract that requires a recommended option for the supply of a minimum 70MW (76.4MVA) of electrical power to the WTP. This section, therefore, does not account for the deficiency of the Hanford 230kV system in handling projected loads. Both issues must ultimately be handled concurrently so that an efficient solution (technically and economically) can be provided. Hence, the overall recommended option reported in the prior section should receive a higher priority by DOE.

This Study presented 10 options for evaluation. Of these, Option 1 - A6 Substation Electrical Equipment Upgrade (Two 60/80/100MVA transformers and two 13.8kV, 4,000A switchgear), is the recommended option.

Option 1 met the minimum 70MW (76.4MVA) functionality requirement, has the second highest reliability of any of the options reviewed, and has a estimated 2 year duration from time of award of the prime contract. Option 1 also has the second lowest ROM TIC of $12.3M ($1.8M more than Option 7).

Since Option 1 is the second best economically and has the second best reliability, it should be pointed out that Option 7 - Eliminate the A6 Switchgear (Direct Power Feed from the A6 Xfmrs to Bldg 87) is also a technically acceptable design option that has a higher reliability (due to fewer components) and a lower estimated ROM TIC of $10.5M. However, the estimated ROM TIC for both Option 1 and Option 7 fall within the -30% to +50% accuracy range of this estimate. Plus, as pointed out in the body of this study, the TIC for Option 7 did not include the cost for changing the contracts to be able to implement Option 7 nor did it include the cost for the WTP project to revise the safety basis documents. In other words, the $10.5M ROM TIC for Option 7 has a high risk associated with the estimated cost. On top of this, the possible schedule impact to Option 7 as the result of having to modify the WTP project's design contract and the site operations contracts would be in addition to the 2 year estimated installation time required to implement Option 7. Additionally, during the review of this study, the WTP project indicated that Option 7 could adversely impact that projects schedule completion. Based on these issues Option 7 has a higher schedule risk as compared to Option 1.

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Since Option 1 maintains the same electrical configuration as is currently employed in the A6 Substation, maintaining the same jurisdictional boundaries that exist in the current operations contracts and WTP Project contract, this option eliminates both the cost and schedule risks that are discussed above for Option 7.

It should be pointed out that the impedance (%Z) of the transformers will have to be chosen such that the short circuit current doesn't exceed the 28kAIC rating of the WTP 13.8kV switchgear in Building 87. This is true for all options that increase the available MVA for a given circuit.

Option 6 – Warehoused Spare Transformer should be mentioned as an option to implement the IEEE C57.91 IEEE Guide for Loading Mineral-Oil-Immersed Transformers, section 9.5 Long Time Emergency Loading. This guide allows for exceeding the name plate rating of a transformer, while maintaining specified temperature parameters, for up to several months and can occur 2 or 3 times over the normal life of the transformer. This option is pertinent since full plant operations, while on a single A6 Substation power source, would occur infrequently. This option, not accounting for storage cost, would cost the price of a single existing transformer, ROM $1.5M. Assuming the work packages were prepared ahead of time for the replacement of a failed transformer, it should take approximately 4-6 months (ROM), per the Hanford 230kV electric utility operator, to remove the failed transformer, install the warehouse spare transformer, and commission the transformer for full operations.

It should be noted that during emergency loading of a single transformer, the maximum power that could be supplied would still be limited to 71.7MVA, based on the 3,000 amp rating of the A6 13.8kV switchgear. Maintaining the 15% contingency, 15% operational growth factor, and using the 91.6% power factor to calculate the maximum load that can be supported, results in 50.5MW (55.1MVA); which is still less than the 53MW (57.9MVA) from WTP Load Flow Calc that is required. However, if a PFCS is used to maintain a 97% power factor, the maximum power that can be supplied would be 53.5MW (55.1MVA); effectively the same as the WTP Load Flow Calc. In other words, there would be no design growth factor to cover additional design load changes over the next approximate 5 years to title III design complete.

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F. Loss of Transformer Fan Cooling

The transformer manufacturer's directions for transformer operations (loading) should be followed. If the transformer is to be operated outside of the transformer manufacturer's recommend range of operation, the transformer manufacturer should be consulted. In addition to the manufacturer's recommendation, IEEE C57.91 Appendix H Section H.3 provides the following. For a multistage fan cooled transformer (ONAN/ONAF/ONAF), the loss of a single stage of fan cooling would drop the maximum transformer rating to the first stage of fan cooling rating. The loss of both stages of fan cooling reduces the maximum transformer rating to the base transformer rating.

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XIV. REFERENCES

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2. Feasibility Study To Use The Present 13.8kV Construction Power As the Fifth Feeder To WTP, 24590-WTP-ES-E-09-001 Rev. 0
3. ICD 11 – Interface Control Document for Electricity, 24590-WTP-ICD-MG-01-011, Rev. 4
4. BOF Facilities Power Distribution (MVE) Main Single Line Diagram, 24590-BOF-E1-MVE-00001, Rev. 6
5. CCN 200152 Contract No. DE-AC27-01RV14136 – Waste Treatment and Immobilization Plant (WTP) Project Load Analysis Contingency, Dated May 28th, 2009
6. CCN 19611 Contract No. DE-AC27-01RV14136 –WTP Electrical Load Analysis Estimate, Dated April 9th, 2009
7. CCN 194415 Contract No. DE-AC27-01RV14136 – Waste Treatment and Immobilization Plant Project (WTP) Electrical Load Analysis Estimate, Dated February 10, 2009
8. A6 230kV & 13.8kV SIMPLIFIED ONE-LINE, H-2-829795 Rev. 5
9. A6 230kV & 13.8kV ONE-LINE DIAGRAM, H-2-829796 Rev. 6
10. Substation Plan View, H-2-829799 Rev. 0
11. Switchgear Building Equipment Plan, H-2-829825 Rev. 0
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14. Switchgear Building 13.8kV MVE-SWGR-87002A & 87002B Single Line Diagram, 24590-BOF-E1-MVE-00003 Rev 8
15. Basis of Design, 24590-WTP-DB-ENG-01-001 Rev 10
16. Electrical Design Criteria, 24590-WTP-DC-E-01-001 Rev 7
17. Request to Permit use of % Loading Factor and Diversity Factor for Equipment and Conductor Sizing, 24590-WTP-AHJ-E-08-0004

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18. A8 230kV One-Line Diagram, H-2-90075 Rev 15
19. BPA Transmission Services, 2010 Transmission and Ancillary Services Rate Schedule; a copy can be found on the web at http://www.transmission.bpa.gov/Business/Rates/documents/2010_Rate_Schedules_10_01_09.pdf
20. Electrical Hanford Plant High Voltage Lines, H-5-255 Rev. 13
21. Electrical 230kV Single Line Switching Diagram, H-5-102 Rev 36.pdf
22. Assessment of the Electrical Power Requirements for Continued Safe Storage and Waste Feed Delivery, RPP-5228 Rev 1
23. 230kV Impedance Diagram, H-6-13436 Rev 5
24. Conceptual Design Report for Effluent Treatment Facility Solidification Treatment Unit, HNF-26914 Rev 0
25. WRPS-1000326_R4__Letter Removing SKM from Scope.pdf
26. Meeting Minutes Dated July 22, 2010, 0700 hours, Titled Analysis of Power Delivery to WTP Engineering Study Options Presentations.pdf

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XV. ATTACHMENTS

1. Budgetary Quote from Northeast Power Systems Incorporated
2. Email with Substation Cost Estimates from Warren Goodwin, URS Estimator, Dated Thursday, May 21, 2010 2:51 PM
3. A6 Substation Plan View Estimate Sketch
4. A6 Substation 70MW (76.4MVA) Options Cost Estimate Worksheet
5. Bonneville Power Administration Customer Service Engineering Meter Diagram USDOE – RICHLAND Customer #10426, Dated 1/11/2008
6. Power Factor Correction Cost Benefit Analysis Estimate Worksheet for .80 pf
7. Power Factor Correction Cost Benefit Analysis Estimate Worksheet for 91.6% pf
8. Email from MSA Stating BPA Does Not Charge a Power Factor Penalty
9. OMNICABLE Overhead Line Ampacity Chart
10. Hanford 230kV Existing Loads
11. Hanford 230kV System Projected Loads
12. Encapsulation and ARF Electrical Loading
13. Estimated 2nd LAW and Support Facilities Electrical Loading
14. Interim Hanford Storage Facility
15. B and T Farm Special Waste Retrieval and Packaging
16. Tank Waste Operations Center
17. East and West Supplemental Treatment

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Wilkins, Jeremy D

From: Paul Lawless [paul.lawless@nepsi.com]
Sent: Wednesday, May 19, 2010 2:03 PM
To: Wilkins, Jeremy D
Cc: frank.steciuk@nepsi.com; paul Steciuk
Subject: Hanford DOE Site - Richland, WA - Washington River Protection

Jeremy,

Confirming our phone conversation of this date, I am pleased to quote you the following:

For each offer below, a corresponding 5th tuned filter bank with the same features would cost about 1.8X the quoted capacitor bank prices.

Offer 1:

Qty (1) 13.8kV, 95kV BIL, 60Hz, 3-ph, ***15 MVAR, 5-Stage, 5-Step***, Metal Enclosed Capacitor Bank

Cost: $135,000

Includes the following primary components:

- (1) NEMA 3R enclosure, 11 gauge, A60 galvanneal sheet steel, with windows, door-stays, dust filters, enclosure by NEPSI
- (3) Surge arresters, 15kV, 12.7kV MCOV, station class, by General Electric
- (1) Isolation switch, 17kV, 1200A, 40kA, interlocked, fused, by ABB
- (1) Ground switch, 4-pole, 17kV, 1200A, 40kA, interlocked, by ABB
- (1) CPT, 13.8kV/120VAC, 3kVa, fused
- (15) Vacuum switches, 15kV, 200A, 95kV BIL, 60Hz, 120VAC control
- (30) Capacitors, 500kVar, 7.96V, 60Hz, 95kV BIL, 2-bushing, externally fused, by General Electric or Cooper
- (15) Capacitor fuses, 17kV, 125A, 40kA, by SIBA, current-limiting, by SIBA
- (5) Unbalance protection systems, SIBA micro-switch
- (15) Current limiting reactors, 200A, 47uH, 15kV, by TRENCO
- (1) Power factor controller, Nokian NC-12, with on/off/auto controls for each stage
- (1) Lot exhaust fans, thermostatically controlled
- (1) Lot misc. controls (lights, indicators, switches, fans, etc.)
- (1) Lot interlocks, by Kirk
- (1) Lot stainless steel hardware
- (1) Lot tin-plated copper bus
- (1) Lot insulators

Approximate Dimensions / Weight

32'L x 7'D x 8'6"H / 15,000 pounds (single-piece construction, all-welded design)

Offer 2:

Qty (1) 13.8kV, 95kV BIL, 60Hz, 3-ph, ***10 MVAR, 3-Stage, 3-Step***, Metal Enclosed Capacitor Bank

Cost: $105,000

Includes the following primary components:

- (1) NEMA 3R enclosure, 11 gauge, A60 galvanneal sheet steel, with windows, door-stays, dust filters, enclosure by NEPSI
- (3) Surge arresters, 15kV, 12.7kV MCOV, station class, by General Electric
- (1) Isolation switch, 17kV, 1200A, 40kA, interlocked, fused, by ABB
- (1) Ground switch, 4-pole, 17kV, 1200A, 40kA, interlocked, by ABB
- (1) CPT, 13.8kV/120VAC, 3kVa, fused
- (9) Vacuum switches, 15kV, 200A, 95kV BIL, 60Hz, 120VAC control

- (18) Capacitors, 555kVar, 7.96V, 60Hz, 95kV BIL, 2-bushing, externally fused, by General Electric or Cooper
- (18) Capacitor fuses, 17kV, 125A, 40kA, by SIBA, current-limiting, by SIBA
- (3) Unbalance protection systems, SIBA micro-switch
- (9) Current limiting reactors, 200A, 47uH, 15kV, by TRENCO
- (1) Power factor controller, Nokian NC-12, with on/off/auto controls for each stage
- (1) Lot exhaust fans, thermostatically controlled
- (1) Lot misc. controls (lights, indicators, switches, fans, etc.)
- (1) Lot interlocks, by Kirk
- (1) Lot stainless steel hardware
- (1) Lot tin-plated copper bus
- (1) Lot insulators

Approximate Dimensions / Weight
25'L x 7'D x 8'6"H / 11,000 pounds (single-piece construction, all-welded design)

Offer 3:
Qty (1) 13.8kV, 95kV BIL, 60Hz, 3-ph, ***5 MVAR, 2-Stage, 2-Step***, Metal Enclosed Capacitor Bank
Cost: $85,000
Includes the following primary components:
- (1) NEMA 3R enclosure, 11 gauge, A60 galvanneal sheet steel, with windows, door-stays, dust filters, enclosure by NEPSI
- (3) Surge arresters, 15kV, 12.7kV MCOV, station class, by General Electric
- (1) Isolation switch, 17kV, 600A, 40kA, interlocked, fused, by ABB
- (1) Ground switch, 4-pole, 17kV, 600A, 40kA, interlocked, by ABB
- (1) CPT, 13.8kV/120VAC, 3kVa, fused
- (6) Vacuum switches, 15kV, 200A, 95kV BIL, 60Hz, 120VAC control
- (12) Capacitors, 416 kVar, 7.96V, 60Hz, 95kV BIL, 2-bushing, externally fused, by General Electric or Cooper
- (12) Capacitor fuses, 17kV, 125A, 40kA, by SIBA, current-limiting, by SIBA
- (2) Unbalance protection systems, SIBA micro-switch
- (6) Current limiting reactors, 200A, 47uH, 15kV, by TRENCO
- (1) Power factor controller, Nokian NC-12, with on/off/auto controls for each stage
- (1) Lot exhaust fans, thermostatically controlled
- (1) Lot misc. controls (lights, indicators, switches, fans, etc.)
- (1) Lot interlocks, by Kirk
- (1) Lot stainless steel hardware
- (1) Lot tin-plated copper bus
- (1) Lot insulators

Approximate Dimensions / Weight
16'L x 7'D x 8'6"H / 8,000 pounds (single-piece construction, all-welded design)

Offer 4:
Qty (1) 13.8kV, 95kV BIL, 60Hz, 3-ph, ***1 MVAR, 1-Step***, Metal Enclosed Capacitor Bank
Cost: $45,000
Includes the following primary components:
- (1) NEMA 3R enclosure, 11 gauge, A60 galvanneal sheet steel, with windows, door-stays, dust filters, enclosure by NEPSI
- (3) Surge arresters, 15kV, 12.7kV MCOV, station class, by General Electric
- (1) Isolation switch, 17kV, 600A, 40kA, interlocked, fused, by ABB
- (1) Ground switch, 4-pole, 17kV, 600A, 40kA, interlocked, by ABB
- (1) CPT, 13.8kV/120VAC, 3kVa, fused

- (3) Vacuum switches, 15kV, 200A, 95kV BIL, 60Hz, 120VAC control
- (3) Capacitors, 333 kVar, 7.96V, 60Hz, 95kV BIL, 2-bushing, externally fused, by General Electric or Cooper
- (3) Capacitor fuses, 17kV, 100A, 40kA, by SIBA, current-limiting, by SIBA
- (1) Unbalance protection systems, SIBA micro-switch
- (3) Current limiting reactors, 200A, 47uH, 15kV, by TRENCO
- (1) Power factor controller, Nokian NC-12, with on/off/auto controls for each stage
- (1) Lot exhaust fans, thermostatically controlled
- (1) Lot misc. controls (lights, indicators, switches, fans, etc.)
- (1) Lot interlocks, by Kirk
- (1) Lot stainless steel hardware
- (1) Lot tin-plated copper bus
- (1) Lot insulators

Approximate Dimensions / Weight
7'L x 5'D x 8'6"H / 4,000 pounds (single-piece construction, all-welded design)

Not Included as Standard In Above Offers:
Harmonic filters, circuit breaker, main fuses, on-site costs, 3rd party testing.

On-site Field Service Rate:
$1,800 per week day, not including travel expenses. Travel time charged at ½ daily rate.

Payment Terms:
NET 30 days after shipment.

Submittals:
Drawings will be provided within 1 week ARO.

Freight:
Freight prepaid and **ADDED to Invoice**, fob destination.

Warranty Period
12/21 months (energization/shipment)

Shipment Schedule:
11-13 weeks after drawing approval.

Quotation Disclaimers

1. We reserve the right to review and take exception to any specification that may apply to this project or to withdraw this quotation in its entirety.

2. Caution: If your customer's facility contains non-linear load devices, adding capacitors to the electrical system may amplify destructive harmonic voltages and current and may lead to premature failure and void the warranty of the capacitors or other electrical components. Examples of non-linear devices: AC/DC Drives, Variable Frequency Drives, Programmable Controllers, Induction Furnaces, Solid State UPS, Arc Furnaces, Arc Welders, Electronic Power Converters, etc. Note: Do not mix filtered and non-filtered capacitors on the same transformer circuit.

Call with questions.
Paul

Northeast Power Systems, Inc.
Paul S. Lawless
66 Carey Road
Queensbury, NY 12804

Attachment 1

(518) 792-4776 Phone
(518) 792-5767 Fax
mailto:paul.lawless@nepsi.com

Budgetary Quote from Northeast
Power Systems Incorporated

ANALYSIS OF POWER DELIVERY TO THE
WTP TO ACHIEVE A MINIMUM OF 70MW
URS STUDY #: 17-05-110-001 Rev 0
WRPS Report #: RPP-RPT-46992 Rev 0

Wilkins, Jeremy D

From: Goodwin, Warren [Warren.Goodwin@wgint.com]
Sent: Friday, May 21, 2010 2:51 PM
To: Wilkins, Jeremy D
Subject: RE: WTP A6 Substation Cost Estimate

My experience for engineering is 15-20%. Probably for a substation I would be in the 15% range. That includes engineering and the other office/staff support hrs.
What is the contract stratergy for construction? Direct Hire or Subcontractors? The indirect cost on most of our large oil and gas projects range from 50% to 100% of the direct costs.
I'll be in the office on Monday through Wednesday.
Warren

From: Wilkins, Jeremy D [mailto:Jeremy_D_Wilkins@rl.gov]
Sent: Friday, May 21, 2010 3:29 PM
To: Goodwin, Warren
Subject: RE: WTP A6 Substation Cost Estimate

They don't. Their expecting URS (i.e. you and I) to handle the entire pricing of the options. So if you have any rules of thumb to use, please let me know.

From my experience, engineering is normally about 10-15% of the total project cost.

I don't have any rules of thumb for indirect. If you have any, please shoot them my way.

From: Goodwin, Warren [mailto:Warren.Goodwin@wgint.com]
Sent: Friday, May 21, 2010 1:48 PM
To: Wilkins, Jeremy D
Subject: RE: WTP A6 Substation Cost Estimate

I won't be in the office on the 31st., but should be in on June 1st..
Your assumptions look OK to me. If you use the cost/MW for the overall substation cost and add the ductbank, busduct and swgr bldg cost that should cover your direct field costs. How do they handle the engineering and indirect costs?

From: Wilkins, Jeremy D [mailto:Jeremy_D_Wilkins@rl.gov]
Sent: Friday, May 21, 2010 9:28 AM
To: Goodwin, Warren
Subject: RE: WTP A6 Substation Cost Estimate

Thanks.

For the cases where I only have equipment capital cost I was planning on an ala carte method for the capitol cost, with a 100% multiplier of the total capital cost to cover the labor; broken out for each of the options that are being evaluated. I wasn't planning on a contingency, but indicating a confidence factor in the estimate. Given that this is a ROM (-30%+50%), I figured this would be adequate. Feel free to comment on method or percentages.

Example:

Swgr Cost = 2 X $1M = $2M
Xfmr Cost = 2 X $2M = $4M
Total Capital = $6M

Labor = $6M

TIC = $12M

Confidence level is Medium. This is due to the possibility of unforeseen complications in the physical details of modifying the existing equipment, plus lack of Hanford labor rate information.

For the rest of the cases where you have pricing per foot, per square foot, or per MW; this is what I intend on using, adding anything extra in as you have suggested. The estimate summary is going to be in the form of a list of bullets in the report.

Suggestions are always welcome. Don't forget, I'm counting on you to review the estimates in the report. You should have the report on May 31st.

Appreciate your help.

Jeremy Wilkins, P.E.
Electrical Engineer
Washington River Protection Solutions/URS
Email: Jeremy_D_Wilkins@rl.gov
Office: 509-376-1041
Cell: 509-551-7917

From: Goodwin, Warren [mailto:Warren.Goodwin@wgint.com]
Sent: Friday, May 21, 2010 7:58 AM
To: Wilkins, Jeremy D
Subject: RE: WTP A6 Substation Cost Estimate

Jeremy,
I have listed 10 hrs this week and what ever I can help support you next week, maybe another 8 hrs. I'll be traveling sometime next week, but you can reach me by cell phone.
For your estimates, at the level of estimate I would use the cost/MW and add the switchgear bldg and bus duct costs. You also mentioned the underground duct bank, I would also add this cost to the estimate. You have my cost/MW and I'll send you the other costs today (swgr bldg, bus duct and duct bank).
Are you going to roll these costs up to a summary sheet? You are probably going to include engineering cost and a contingency? I'm not sure what you use to present your estimates, but I believe there is an estimator at the Hanford site just not sure where at or if you have access to this group. If I can help you on this estimate summary document let me know.
Warren

From: Wilkins, Jeremy D [mailto:Jeremy_D_Wilkins@rl.gov]
Sent: Thursday, May 20, 2010 11:44 AM
To: Goodwin, Warren
Subject: RE: WTP A6 Substation Cost Estimate

Thanks,

By the way, here is the charge code for estimating support.

29906-1.39505.041.61.58.00.000

Let me know how many hours you think you're going to need to support this task. Be aware that I'm going to send you my report for your review on May 31st. Another words, added a few hours for the final review.

Thanks for your help.

Jeremy Wilkins, P.E.
Electrical Engineer
Washington River Protection Solutions/URS
Email: Jeremy_D_Wilkins@rl.gov
Office: 509-376-1041
Cell: 509-551-7917

From: Goodwin, Warren [mailto:Warren.Goodwin@wgint.com]
Sent: Thursday, May 20, 2010 10:39 AM
To: Wilkins, Jeremy D
Subject: RE: WTP A6 Substation Cost Estimate

Jeremy,

I have some information that may help you for this level of estimate.

The 15kV bus cost and unit man-hour for installation are:
3000amp= $2,680/LF (material cost for an average 100' run with fittings/hangers) + unit man-hour install rate = 4 hrs/LF (no labor productivity factor applied for Hanford site)
4000amp= $3,815/LF (material cost for an average 100' run with fittings/hangers) + unit man-hour install rate = 5.5 hrs/LF (no labor productivity factor applied for Hanford site)

I use $350/SF for a substation Power Distribution Building (PDC) cost only (fully equipped, except no electrical distribution equipment) and $1,000 to $1,200/SF for a PDC cost with electrical distribution equipment (depends on type of equipment and voltage levels).

I also have per MW costs for substation installations:
A lot of our plant substations run around 30MW. I use an average **total field cost** of between $100,000 to $165,000/MW depending on voltage levels, type of equipment, and location.
I had a substation quote in 2007 from a WREA in Colorado. The substation size was 12MVA at 138-24.9kV. Their **TIC (total installed cost)** quote was $155,000/MVA.

I should be available today and tomorrow for any further information you need to support your substation cost estimate. Starting next week I will out of the office for a few weeks, but available by e-mail and cell phone. If you need me to roll up these costs in an estimate format please let me know.

Warren
Warren L. Goodwin
URS Corporation
Senior Consulting Estimator
(303) 843-3025 office
(303) 877-1512 cell
Fax (303) 843-2281
E-Mail: warren.goodwin@wgint.com

From: Wilkins, Jeremy D [mailto:Jeremy_D_Wilkins@rl.gov]
Sent: Wednesday, May 19, 2010 9:33 AM
To: Goodwin, Warren
Subject: WTP A6 Substation Cost Estimate

Warren,

Attachment 2

Email with Substation Cost Estimates
from Warren Goodwin, URS Estimator

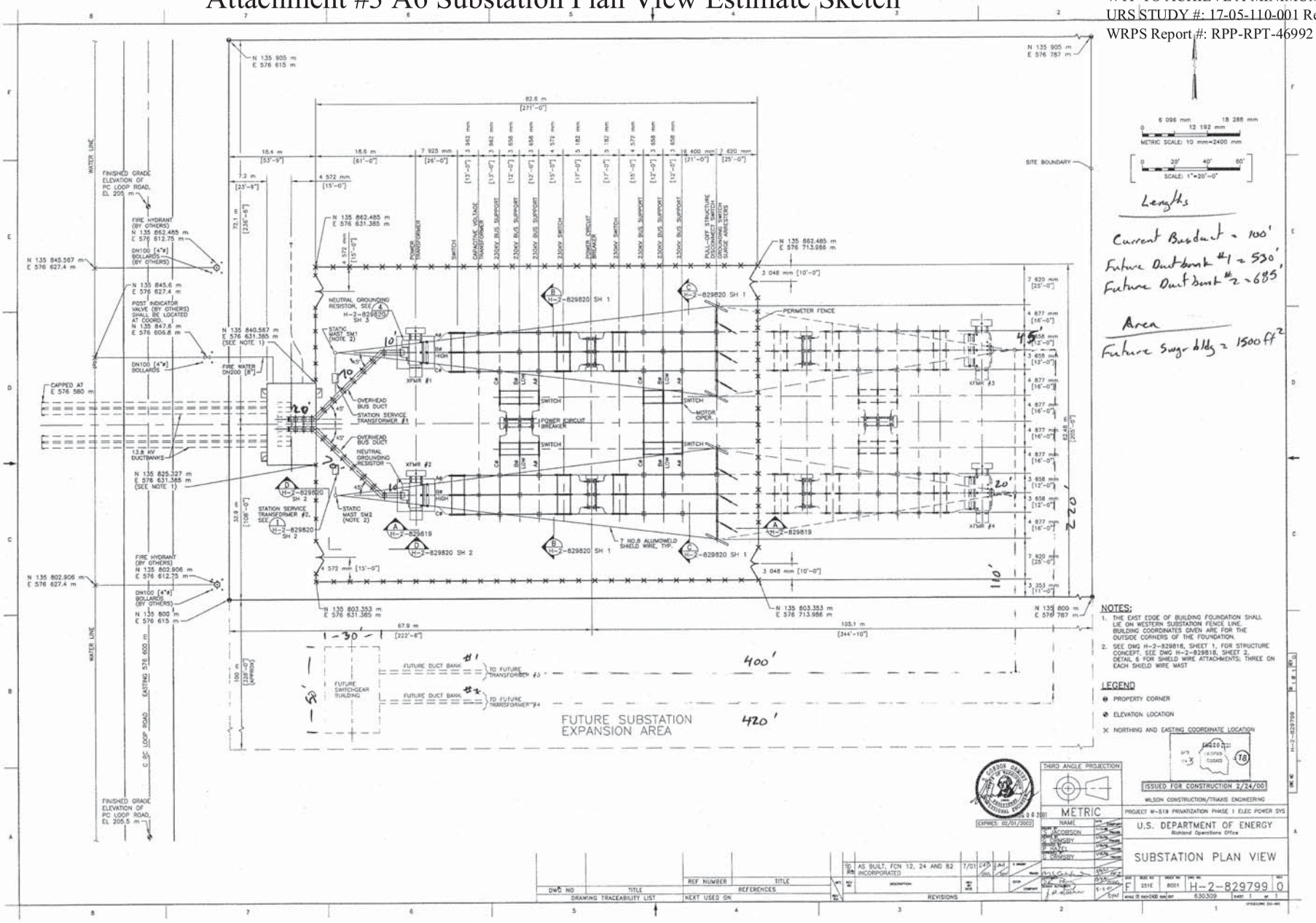
I left a message on your phone regarding the use of your services in obtaining a ROM (-30%+50%) cost estimate for the future portion of the DOE A6 230kV-13.8kV substation. The future portion will be the same as the existing portion, so I'm giving you all of the A6 substation information that I have. This doesn't need to be a highly detailed estimate. I need the information rather quickly, i.e. no later than Tuesday nest week. If I could get it by Friday would even be better.

What I'm hoping for would be a break out of the transformer costs (two options: 37.5/50/62.5MVA OA/FA/FA & 60/80/100MVA OA/FA/FA rated), bus duct cost (two options: 13.8kV 3,000Amp and 13.8kV, 4,000Amp), switchgear cost (13.8kV, 3,000Amp, with Main-Tie-Main and 6 feeder breakers), and switchgear bldg costs (sized and configuration as shown in the attached file).

Please get back to me at your earliest convenience.

Jeremy Wilkins, P.E.
Electrical Engineer
Washington River Protection Solutions/URS
Email: Jeremy_D_Wilkins@rl.gov
Office: 509-376-1041
Cell: 509-551-7917

Attachment #3 A6 Substation Plan View Estimate Sketch



Attachment 4 - A6 Substation 70MW Options Cost Estimate Worksheet

ANALYSIS OF POWER DELIVERY TO THE WTP
TO ACHIEVE A MINIMUM OF 70MW
URS STUDY #: 17-05-110-001 Rev 0
WRPS Report #: RPP-RPT-46992 Rev 0

Option 1

Status	Material	Quantity (1)	Units	Price (2)	Price Source	Units	Material Cost (3)=(1)*(2)	Eng & Proc Hours (4)	Eng & Proc Hourly Rate (5)	Total Eng & Proc Cost (6)=(4)*(5)	Labor Rates (7)	Units	Labor Hours (8)=(1)*(7)	Labor Hourly Rate (9)	Total Labor Cost (10)=(8)*(9)	Total Direct Cost ($K) (11)=(3)+(6)+(10)	Indirects 75% of Direct cost ($K) (12)=(11)*0.75	Total EPC ($K) (13)=(11)+(12)	C&T 10% of EPC ($K) (14)=(13)*0.1	TIC ($K) (15)=(13)+(14)
Add	60/80/100MVA Xfmr	2	Each	$2,000,000	ABB	per xfmr	$4,000,000	700	$100	$70,000	600	per xfmr	1,200	$80	$96,000	$4,166	$3,125	$7,291	$729	$8,020
Add	4,000 Amp Bus Duct	200	LF	$4,000	URS	per LF	$800,000	700	$100	$70,000	9.0	per LF	1,800	$80	$144,000	$1,014	$761	$1,775	$177	$1,952
Add	13.8kV, 4,000Amp, 3W, 60Hz, 28kA(RMS)	9	Vertical Sections	$100,000	ABB	per Section	$900,000	1,000	$100	$100,000	50	per Section	450	$80	$36,000	$1,036	$777	$1,813	$181	$1,994
Remove	37/50/62MVA Xfmr	2	Each	$0		per xfmr	$0	200	$100	$20,000	300	per xfmr	600	$80	$48,000	$68	$51	$119		$119
Remove	3,000 Amp Bus Duct	200	LF	$0		per LF	$0	200	$100	$20,000	4.5	per LF	900	$80	$72,000	$92	$69	$161		$161
Remove	13.8kV, 3,000Amp, 3W, 60Hz, 28kA(RMS)	9	Vertical Sections	$0		per Section	$0	200	$100	$20,000	25	per Section	225	$80	$18,000	$38	$29	$67		$67
							$5,700,000	3,000		$300,000			5,175		$414,000	$6,414	$4,811	$11,225	$1,088	$12,312

Option 2

Status	Material	Quantity (1)	Units	Price (2)	Price Source	Units	Material Cost (3)=(1)*(2)	Eng & Proc Hours (4)	Eng & Proc Hourly Rate (5)	Total Eng & Proc Cost (6)=(4)*(5)	Labor Rates (7)	Units	Labor Hours (8)=(1)*(7)	Labor Hourly Rate (9)	Total Labor Cost (10)=(8)*(9)	Total Direct Cost ($K) (11)=(3)+(6)+(10)	Indirects 75% of Direct cost ($K) (12)=(11)*0.75	Total EPC ($K) (13)=(11)+(12)	C&T 10% of EPC ($K) (14)=(13)*0.1	TIC ($K) (15)=(13)+(14)
Add	60/80/100MVA Xfmr	2	Each	$2,000,000	ABB	per xfmr	$4,000,000	700	$100	$70,000	600	per xfmr	1,200	$80	$96,000	$4,166	$3,125	$7,291	$729	$8,020
Add	3,000 Amp Bus Duct	800	LF	$3,000	URS	per LF	$2,400,000	700	$100	$70,000	6.75	per LF	5,400	$80	$432,000	$2,902	$2,177	$5,079	$508	$5,586
Add	13.8kV, 3,000Amp, 3W, 60Hz, 28kA(RMS)	9	Vertical Sections	$100,000	ABB	per Section	$900,000	1,000	$100	$100,000	50	per Section	450	$80	$36,000	$1,036	$777	$1,813	$181	$1,994
Add	13.8kV Duct Bank	1,200	LF	$125		per LF	$150,000	500	$100	$50,000	4.5	per LF	5,400	$80	$432,000	$632	$474	$1,106	$111	$1,217
Add	13.8kV Swgr Bldg	3,000	sqft	$500		per sq ft	$1,500,000	0	$100	$0	0	per LF	0	$80	$0	$0	$0	$0	$0	$1,500
Remove	37/50/62MVA Xfmr	2	Each	$0		per xfmr	$0	200	$100	$20,000	300	per xfmr	600	$80	$48,000	$68	$51	$119	$12	$131
							$8,950,000	3,100		$310,000			13,050		$1,044,000	$8,804	$6,603	$15,407	$1,541	$18,448

Option 4

Status	Material	Quantity (1)	Units	Price (2)	Price Source	Units	Material Cost (3)=(1)*(2)	Eng & Proc Hours (4)	Eng & Proc Hourly Rate (5)	Total Eng & Proc Cost (6)=(4)*(5)	Labor Rates (7)	Units	Labor Hours (8)=(1)*(7)	Labor Hourly Rate (9)	Total Labor Cost (10)=(8)*(9)	Total Direct Cost ($K) (11)=(3)+(6)+(10)	Indirects 75% of Direct cost ($K) (12)=(11)*0.75	Total EPC ($K) (13)=(11)+(12)	C&T 10% of EPC ($K) (14)=(13)*0.1	TIC ($K) (15)=(13)+(14)
Add	37/50/62MVA Xfmr	2	Each	$1,500,000	ABB	per xfmr	$3,000,000	700	$100	$70,000	600	per xfmr	1,200	$80	$96,000	$3,166	$2,375	$5,541	$554	$6,095
Add	3,000 Amp Bus Duct	800	LF	$3,000	URS	per LF	$2,400,000	700	$100	$70,000	6.75	per LF	5,400	$80	$432,000	$2,902	$2,177	$5,079	$508	$5,586
Add	13.8kV, 3,000Amp, 3W, 60Hz, 28kA(RMS)	9	Vertical Sections	$100,000	ABB	per Section	$900,000	1,000	$100	$100,000	50	per Section	450	$80	$36,000	$1,036	$777	$1,813	$181	$1,994
Add	13.8kV Duct Bank	2,400	LF	$125		per LF	$300,000	500	$100	$50,000	4.5	per LF	10,800	$80	$864,000	$1,214	$911	$2,125	$212	$2,337
Add	13.8kV Swgr Bldg	3,000	sqft	$500		per sq ft	$1,500,000		$100	$0	0	per LF	0	$80	$0	$0	$0	$0	$0	$1,500
							$8,100,000	2,900		$290,000			17,850		$1,428,000	$8,318	$6,239	$14,557	$1,456	$17,512

Option 5 - Swing Bus

Status	Material	Quantity (1)	Units	Price (2)	Price Source	Units	Material Cost (3)=(1)*(2)	Eng & Proc Hours (4)	Eng & Proc Hourly Rate (5)	Total Eng & Proc Cost (6)=(4)*(5)	Labor Rates (7)	Units	Labor Hours (8)=(1)*(7)	Labor Hourly Rate (9)	Total Labor Cost (10)=(8)*(9)	Total Direct Cost ($K) (11)=(3)+(6)+(10)	Indirects 75% of Direct cost ($K) (12)=(11)*0.75	Total EPC ($K) (13)=(11)+(12)	C&T 10% of EPC ($K) (14)=(13)*0.1	TIC ($K) (15)=(13)+(14)
Add	37/50/62MVA Xfmr	1	Each	$1,500,000	ABB	per xfmr	$1,500,000	700	$100	$70,000	600	per xfmr	600	$80	$48,000	$1,618	$1,214	$2,832	$283	$3,115
Add	3,000 Amp Bus Duct (1 new)	200	LF	$3,000	URS	per LF	$600,000	700	$100	$70,000	6.75	per LF	1,350	$80	$108,000	$778	$584	$1,362	$136	$1,498
Add	3,000 Amp Bus Duct (1 modified)	100	LF	$3,000	URS	per LF	$300,000	700	$100	$70,000	6.75	per LF	675	$80	$54,000	$424	$318	$742	$74	$816
Add	13.8kV, 3,000Amp, 3W, 60Hz, 28kA(RMS)	2	Vertical Sections	$150,000	ABB	per Section	$300,000	1,000	$100	$100,000	50	per Section	100	$80	$8,000	$408	$306	$714	$71	$785
Add	13.8kV, 3,000Amp, 3W, 60Hz, 28kA(RMS)	4	Vertical Sections	$0	ABB	per Section	$0	500	$100	$50,000	50	per Section	200	$80	$16,000	$66	$50	$116	$12	$127
Add	230kV, 1200A breaker	3	Each	$250,000	ABB	per Section	$750,000	1,000	$100	$100,000	400	Each	1,200	$80	$96,000	$946	$710	$1,656	$166	$1,821
Add	230kV, Substation Hardware	1	Each	$500,000	ABB	per Section	$500,000	500	$100	$50,000	600	Each	600	$80	$48,000	$598	$449	$1,047	$105	$1,151
Add	13.8kV Duct Bank (2X3 duct configuration)	1,600	LF	$125	URS	per LF	$200,000	500	$100	$50,000	4.5	per LF	7,200	$80	$576,000	$826	$620	$1,446	$145	$1,590
Add	13.8kV Swgr Bldg	3,000	sqft	$500	URS	per sq ft	$1,500,000	0	$100	$0	0	per LF	0	$80	$0	$0	$0	$0	$0	$1,500
Remove	13.8kV, 3,000Amp, 3W, 60Hz, 28kA(RMS)	4	Vertical Sections	$0		per Section	$0	200	$100	$20,000	25	per Section	100	$80	$8,000	$28	$21	$49		$49
Remove	3,000 Amp Busduct	100	LF	$0		per LF	$0	200	$100	$20,000	4.5	per LF	450	$80	$36,000	$56	$42	$98		$98
							$5,650,000	6,000		$600,000			12,475		$998,000	$5,748	$4,311	$10,059	$991	$12,550

Attachment 4 - A6 Substation 70MW Options Cost Estimate Worksheet

Option 7 - Eliminate the A6 Substation, Direct Feed to B87 with Cable

Status	Material	Quantity (1)	Units	Price (2)	Price Source	Units	Material Cost (3)=(1)*(2)	Eng & Proc Hours (4)	Eng & Proc Hourly Rate (5)	Total Eng & Proc Cost (6)=(4)*(5)	Labor Rates (7)	Units	Labor Hours (8)=(1)*(7)	Labor Hourly Rate (9)	Total Labor Cost (10)=(8)*(9)	Total Direct Cost ($K) (11)=(3)+(6)+(10)	Indirects 75% of Direct cost ($K) (12)=(11)*0.75	Total EPC ($K) (13)=(11)+(12)	C&T 10% of EPC ($K) (14)=(13)*0.1	TIC ($K) (15)=(13)+(14)
Add	60/80/100MVA Xfmr	2	Each	$2,000,000	ABB	per xfmr	$4,000,000	700	$100	$70,000	600	per xfmr	1,200	$80	$96,000	$4,166	$3,125	$7,291	$729	$8,020
Add	13.8kV Ductbank	400	LF	$250		per LF	$100,000	500	$100	$50,000	4.5	per LF	1,800	$80	$144,000	$294	$221	$515	$51	$566
Add	Control Power Ductbank	600	LF	$100		per LF	$60,000	500	$100	$50,000	4.5	per LF	2,700	$80	$216,000	$326	$245	$571	$57	$628
Add	13.8kV, 2,000Amp, 3W, 60Hz, 28kA(RMS)	4	Vertical Sections	$100,000	ABB	per Section	$400,000	1,000	$100	$100,000	50	per Section	200	$80	$16,000	$516	$387	$903	$90	$993
Remove	37/50/62MVA Xfmr	2	Each	$0		per xfmr	$0	200	$100	$20,000	300	per xfmr	600	$80	$48,000	$68	$51	$119		$119
Remove	3,000 Amp Busduct	200	LF	$0		per LF	$0	200	$100	$20,000	4.5	per LF	900	$80	$72,000	$92	$69	$161		$161
							$4,560,000	3,100		$310,000			7,400		$592,000	$5,462	$4,097	$9,559	$928	$10,486

Hanford 230kV A6 Substation Expansion Option

Status	Material	Quantity (1)	Units	Price (2)	Price Source	Units	Material Cost (3)=(1)*(2)	Eng & Proc Hours (4)	Eng & Proc Hourly Rate (5)	Total Eng & Proc Cost (6)=(4)*(5)	Labor Rates (7)	Units	Labor Hours (8)=(1)*(7)	Labor Hourly Rate (9)	Total Labor Cost (10)=(8)*(9)	Total Direct Cost ($K) (11)=(3)+(6)+(10)	Indirects 75% of Direct cost ($K) (12)=(11)*0.75	Total EPC ($K) (13)=(11)+(12)	C&T 10% of EPC ($K) (14)=(13)*0.1	TIC ($K) (15)=(13)+(14)
Add	60/80/100MVA Xfmr	2	Each	$2,000,000	ABB	per xfmr	$4,000,000	700	$100	$70,000	600	per xfmr	1,200	$80	$96,000	$4,166	$3,125	$7,291	$729	$8,020
Add	3,000 Amp Bus Duct	800	LF	$3,000	URS	per LF	$2,400,000	700	$100	$70,000	6.75	per LF	5,400	$80	$432,000	$2,902	$2,177	$5,079	$508	$5,586
Add	13.8kV, 3,000Amp, 3W, 60Hz, 28kA(RMS)	13	Vertical Sections	$100,000	ABB	per Section	$1,300,000	1,000	$100	$100,000	50	per Section	650	$80	$52,000	$1,452	$1,089	$2,541	$254	$2,795
Add	13.8kV Duct Bank	2,400	LF	$125		per LF	$300,000	500	$100	$50,000	4.5	per LF	10,800	$80	$864,000	$1,214	$911	$2,125	$212	$2,337
Add	13.8kV Swgr Bldg	3,000	sqft	$500		per sq ft	$1,500,000		$100	$0	0	per LF	0	$80	$0	$0	$0	$0	$0	$1,500
							$9,500,000	2,900		$290,000			18,050		$1,444,000	$9,734	$7,301	$17,035	$1,703	$20,238

Capacitor Bank Power Factor Correction System (PFCS)

Status	Material	Quantity (1)	Units	Price (2)	Price Source	Units	Material Cost (3)=(1)*(2)	Eng & Proc Hours (4)	Eng & Proc Hourly Rate (5)	Total Eng & Proc Cost (6)=(4)*(5)	Labor Rates (7)	Units	Labor Hours (8)=(1)*(7)	Labor Hourly Rate (9)	Total Labor Cost (10)=(8)*(9)	Total Direct Cost ($K) (11)=(3)+(6)+(10)	Indirects 75% of Direct cost ($K) (12)=(11)*0.75	Total EPC ($K) (13)=(11)+(12)	C&T 10% of EPC ($K) (14)=(13)*0.1	TIC ($K) (15)=(13)+(14)
Add	15 MVAR Capacitor Bank PFCS	4	Each	$135,000	NEPSI	per unit	$540,000	700	$100	$70,000	150	per unit	600	$80	$48,000	$658	$494	$1,152	$115	$1,267
							$540,000	700		$70,000			600		$48,000	$658	$494	$1,152	$115	$1,267

Filter Bank Power Factor Correction System (PFCS)

Status	Material	Quantity (1)	Units	Price (2)	Price Source	Units	Material Cost (3)=(1)*(2)	Eng & Proc Hours (4)	Eng & Proc Hourly Rate (5)	Total Eng & Proc Cost (6)=(4)*(5)	Labor Rates (7)	Units	Labor Hours (8)=(1)*(7)	Labor Hourly Rate (9)	Total Labor Cost (10)=(8)*(9)	Total Direct Cost ($K) (11)=(3)+(6)+(10)	Indirects 75% of Direct cost ($K) (12)=(11)*0.75	Total EPC ($K) (13)=(11)+(12)	C&T 10% of EPC ($K) (14)=(13)*0.1	TIC ($K) (15)=(13)+(14)
Add	15 MVAR Filter Bank PFCS	4	Each	$243,000	NEPSI	per unit	$972,000	700	$100	$70,000	150	per unit	600	$80	$48,000	$1,090	$818	$1,908	$191	$2,098
							$972,000	700		$70,000			600		$48,000	$1,090	$818	$1,908	$191	$2,098

Capacitor Bank Power Factor Correction System (PFCS) for Fifth Feeder Option

Status	Material	Quantity (1)	Units	Price (2)	Price Source	Units	Material Cost (3)=(1)*(2)	Eng & Proc Hours (4)	Eng & Proc Hourly Rate (5)	Total Eng & Proc Cost (6)=(4)*(5)	Labor Rates (7)	Units	Labor Hours (8)=(1)*(7)	Labor Hourly Rate (9)	Total Labor Cost (10)=(8)*(9)	Total Direct Cost ($K) (11)=(3)+(6)+(10)	Indirects 75% of Direct cost ($K) (12)=(11)*0.75	Total EPC ($K) (13)=(11)+(12)	C&T 10% of EPC ($K) (14)=(13)*0.1	TIC ($K) (15)=(13)+(14)
Add	15 MVAR Capacitor Bank PFCS	6	Each	$135,000	NEPSI	per unit	$810,000	700	$100	$70,000	150	per unit	900	$80	$72,000	$952	$714	$1,666	$167	$1,833
							$810,000	700		$70,000			900		$72,000	$952	$714	$1,666	$167	$1,833

Attachment #5 BPA Customer Service Engineering Meter Diagram

ANALYSIS OF POWER DELIVERY TO THE
WTP TO ACHIEVE A MINIMUM OF 70MW
URS STUDY #: 17-05-110-001 Rev 0
WRPS Report #: RPP-RPT-46992 Rev 0

LEGEND

BPA - BONNEVILLE POWER ADMINISTRATION
BPUD - BENTON PUBLIC UTILITY DISTRICT
DOE-RL- DOE RICHLAND FIELD OFFICE
ENW - ENERGY NORTHWEST (FORMERLY WPPSS)
GCPUD - GRANT COUNTY PUBLIC UTILITY DISTRICT
HWVP - HANFORD WASTE VITRIFICATION PLANT
PPL - PACIFIC POWER AND LIGHT

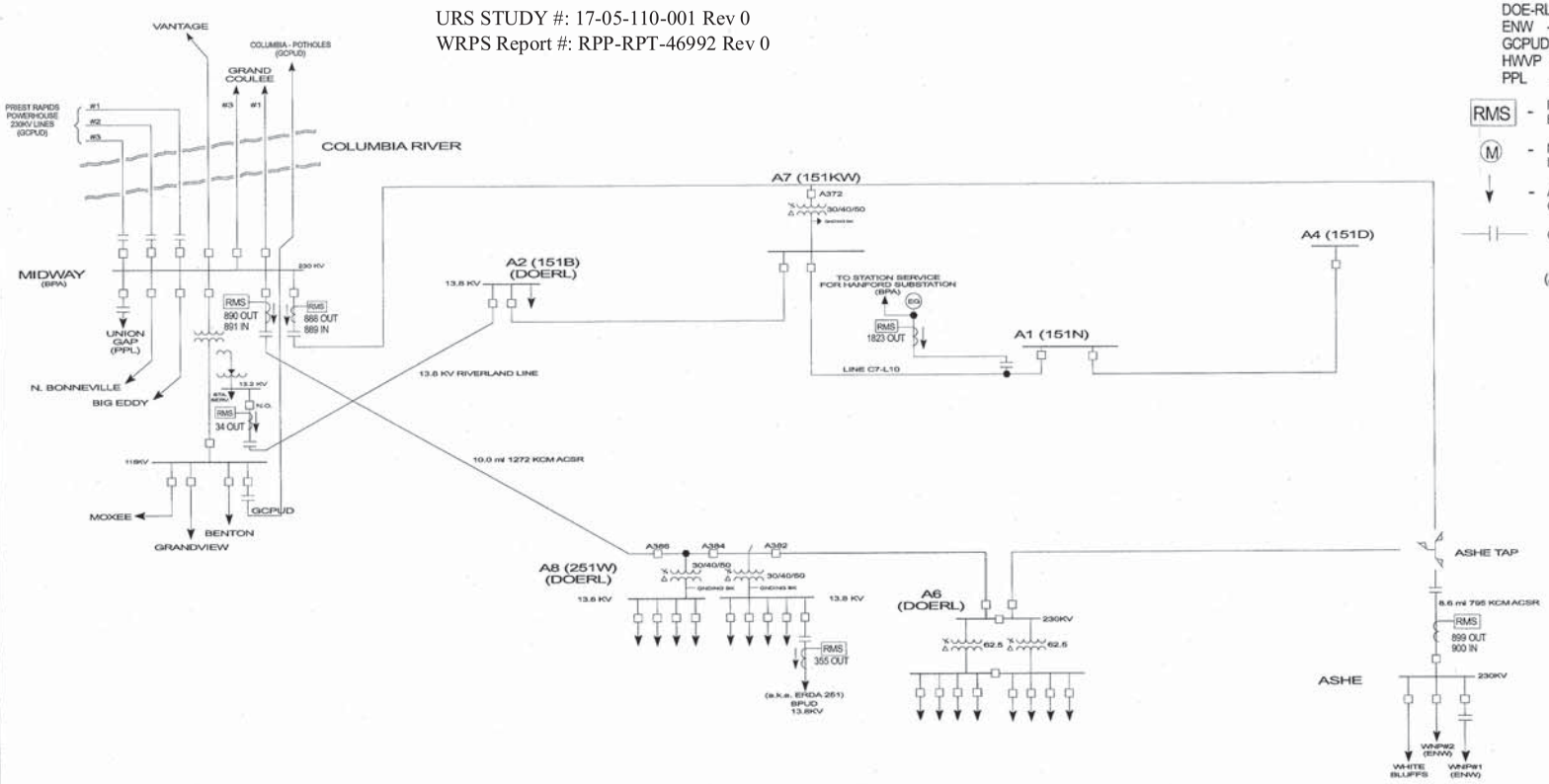
RMS - REMOTE METERING SYSTEM POLLED AUTOMATICALLY BY THE RMS MASTER OR THE MV90 SYSTEM

(M) - MANUAL METER SYSTEM (METER SLIP) READ BY BPA OR THE CUSTOMER

- ARROWS ADJACENT TO METERS SIGNIFY DIRECTION OF ENERGY FLOW OUT OF TBL.

CHANGE IN OWNERSHIP

(ALL TRANSFORMERS RATED IN MVA)



Page 1 of 1

REVISED: 1/11/2008 SHEET 1 OF 2

BONNEVILLE POWER ADMINISTRATION
Customer Service Engineering
Meter Diagram

USDOE - RICHLAND
Customer #10426

CUSTOMER SERVICE ENGINEER:
EARL BROWN - TPC/WALLA WALLA

TOC\METERDIAGRAM\WALLAWALLA\USDOERICHLAND1_Meter.skf

Attachment 6 - Power Factor Corrections Cost Benefit Analysis
80% Lagging Power Factor

			Cost Benefit Analysis Based on a Lagging .80 p.f.						
Percent Load		**(A)**	**100%**	**80%**	**75%**	**60%**	**50%**	**40%**	**25%**
Real Power (MW)		(B)	70	56	52.5	42	35	28	17.5
MVAR @ .8 pf	0.8	(C)=(A)*SIN(ACOS(0.80))	42.0	33.6	31.5	25.2	21.0	16.8	10.5
MVAR @ .97 pf	0.97	(D)=(B)*SIN(ACOS(0.97))	17.0	13.6	12.8	10.2	8.5	6.8	4.3
MVAR assessed a Penalty		(E)=(C)-(D)	25.0	20.0	18.7	15.0	12.5	10.0	6.2
$280 per MVAR below .97 pf	$ 280	(F)=(E)*280	$ 6,995	$ 5,596	$ 5,246	$ 4,197	$ 3,498	$ 2,798	$ 1,749
No Charge for Light Load Hours (LLH)	61%	(G)=(F)*.61	$ 4,267	$ 3,414	$ 3,200	$ 2,560	$ 2,134	$ 1,707	$ 1,067

LLH is defined as 11 pm to 6 am
Monday thru Saturday and all
hours on Sunday or 66 hours per week
Therefore, BPA only charges for power
factor penalty 61% of the time.

TIC for Cap Bank PFCS		(H)	$ 1,267,000	$ 1,267,000	$ 1,267,000	$ 1,267,000	$ 1,267,000	$ 1,267,000	$ 1,267,000
Years to Return on Investment									
assuming no operational cost on PFCS		(I)=(H)/(G)/12	25	31	33	41	49	62	99
TIC for Filter Bank PFCS		(J)	$ 2,098,000	$ 2,098,000	$ 2,098,000	$ 2,098,000	$ 2,098,000	$ 2,098,000	$ 2,098,000
Years to Return on Investment									
assuming no operational cost on PFCS		(K)=(J)/(G)/12	41	51	55	68	82	102	164

Attachment 7 - Power Factor Corrections Cost Benefit Analysis
91.6% Lagging Power Factor

			Cost Benefit Analysis Based on a Lagging .80 p.f.						
Percent Load		**(A)**	**100%**	**80%**	**75%**	**60%**	**50%**	**40%**	**25%**
Real Power (MW)		(B)	70	56	52.5	42	35	28	17.5
MVAR @ .8 pf	0.916	(C)=(A)*SIN(ACOS(0.916))	28.1	22.5	21.1	16.8	14.0	11.2	7.0
MVAR @ .97 pf	0.97	(D)=(B)*SIN(ACOS(0.97))	17.0	13.6	12.8	10.2	8.5	6.8	4.3
MVAR assessed a Penalty		(E)=(C)-(D)	11.1	8.9	8.3	6.6	5.5	4.4	2.8
$280 per MVAR below .97 pf	$ 280	(F)=(E)*280	$ 3,098	$ 2,479	$ 2,324	$ 1,859	$ 1,549	$ 1,239	$ 775
No Charge for Light Load Hours (LLH)	61%	(G)=(F)*.61	$ 1,890	$ 1,512	$ 1,417	$ 1,134	$ 945	$ 756	$ 472

LLH is defined as 11 pm to 6 am
Monday thru Saturday and all
hours on Sunday or 66 hours per week
Therefore, BPA only charges for power
factor penalty 61% of the time.

TIC for Cap Bank PFCS		(H)	$ 1,267,000	$ 1,267,000	$ 1,267,000	$ 1,267,000	$ 1,267,000	$ 1,267,000	$ 1,267,000
Years to Return on Investment									
assuming no operational cost on PFCS		(I)=(H)/(G)/12	56	70	74	93	112	140	223
TIC for Filter Bank PFCS		(J)	$ 2,098,000	$ 2,098,000	$ 2,098,000	$ 2,098,000	$ 2,098,000	$ 2,098,000	$ 2,098,000
Years to Return on Investment									
assuming no operational cost on PFCS		(K)=(J)/(G)/12	93	116	123	154	185	231	370

Wilkins, Jeremy D

From: Ziegenbein, Richard S
Sent: Monday, June 07, 2010 7:20 AM
To: Wilkins, Jeremy D
Subject: FW: Service Catalog Request: Electrical Utilities Services: KSR-4975

I have not read through the document yet. But FYI

Richard Ziegenbein
Washington River Protection Solutions
WTP Interface Management Lead
509 376 0991 office
775 247 8622 cell
1200 Jadwin (347) MS E6-30
Richland, WA 99352

From: Al-Wazani, Mazen G
Sent: Monday, June 07, 2010 7:18 AM
To: Ziegenbein, Richard S
Cc: Olsen, Gary B; Reed, Garth R; Bruggeman, Jeffrey M; Al-Wazani, Mazen G
Subject: FW: Service Catalog Request: Electrical Utilities Services: KSR-4975

FYI

From: Uecker, James E (Jim)
Sent: Monday, June 07, 2010 7:02 AM
To: Al-Wazani, Mazen G
Cc: Baker, Scott (EU); Carlson, Cris E; Hache, Joseph M (Mike); Krekel, Randall N; Oakes, Darlene K
Subject: RE: Service Catalog Request: Electrical Utilities Services: KSR-4975

Mazen,

62 MW @ 0.89 pf = 70 MVA. Would gain 8 MW with 32.5 MVAR capacitor. Without a capacitor, BPA's 73.5 MVAR leading would be reduced to 41 MVAR leading. When operating normally, each transformer would carry 35 MW which is still below the 37 MVA self cooled rating. A single transformer would be at 113% of the forced air rating, which is fine in the winter but may reduce the transformer life slightly in the summer, depending on how long the single transformer condition lasts. Again, this is an operational call.

Another alternative would be to relocate the new 151-KE (A-9) substation to WTP after D&D of 100-K Area is complete in 5 years. The new skid-mounted (mobile) substation will have 2 transformers rated 10/14/17 MVA. This relocation could occur sooner depending on how fast the load at 100-K Area drops off, such that the 13.8 KV tie-line from 251-W (A-8) substation can handle the load.

Jim Uecker
373-1930

From: Al-Wazani, Mazen G
Sent: Thursday, June 03, 2010 1:10 PM
To: Uecker, James E (Jim)
Cc: Baker, Scott (EU); Carlson, Cris E; Hache, Joseph M (Mike); Krekel, Randall N; Oakes, Darlene K
Subject: RE: Service Catalog Request: Electrical Utilities Services: KSR-4975

Jim,

Email from the Hanford 230kV System Operator stating no PF penalty

For your info, the goal is 70MW not 62MW.

Thanks,

Mazen

From: Uecker, James E (Jim)
Sent: Thursday, June 03, 2010 12:28 PM
To: Al-Wazani, Mazen G
Cc: Baker, Scott (EU); Carlson, Cris E; Hache, Joseph M (Mike); Krekel, Randall N; Oakes, Darlene K
Subject: RE: Service Catalog Request: Electrical Utilities Services: KSR-4975

Mazen,

Capacitors can be used to gain capacity. BPA does not assess a power factor penalty against the Hanford 230 KV system because it acts like a big capacitor and generates VAR's which helps to stabilize BPA's voltage. In BPA's loss factor calculations for the 230 KV system, they show 186 MW at a power factor of -0.93 for 200 MVA. This equates to 73.5 MVAR leading. This is the amount that WTP would have to lag in order to reach unity.

If the goal is for WTP to run at 62 MW, then a couple of hypothetical examples are as follows:

Winter: 57 MW @ 0.92 pf = 62 MVA. Would gain 5 MW with 24 MVAR capacitor.
Summer: 54 MW @ 0.87 pf = 62 MVA. Would gain 8 MW with 30 MVAR capacitor.

In these cases, adding the capacitors would leave BPA at 73.5 MVAR leading. Without the capacitors, BPA's leading MVAR's would be reduced by the respective capacitor amounts to 49.5 MVAR or 43.5 MVAR. These examples illustrate the magnitude of capacitor needed for a cost/benefit analysis. The anticipated load and power factor for WTP will determine the actual size of capacitor needed. At this time, capacitors are not needed for power factor correction to avoid penalties.

Jim Uecker
373-1930

From: Hache, Joseph M (Mike)
Sent: Friday, May 07, 2010 3:56 PM
To: Baker, Scott (EU); Uecker, James E (Jim); Krekel, Randall N; Carlson, Cris E
Subject: FW: Service Catalog Request: Electrical Utilities Services: KSR-4975

FYI – heads up
I don't think we are authorized to proceed yet, but here is the first request for info.

Joseph M Hache (Michael)
Electrical Utilities Design Authority
SI&U Engineering Team Lead
PH (509) 373-1853
Fax (509) 372-9734

From: Ziegenbein, Richard S
Sent: Friday, May 07, 2010 11:21 AM
To: Hache, Joseph M (Mike)

Cc: Al-Wazani, Mazen G; Hamm, Earnest R; Wheeler, Martin; Wilkins, Jeremy D
Subject: RE: Service Catalog Request: Electrical Utilities Services: KSR-4975

Hi Mike,

Thanks for the update.

I have located sufficient documentation on the A6 Substation so we should be OK for the moment.

I anticipate one of the first packets of information required will be related to the Hanford power factor. We will need information on rate structure penalties, power factor monitoring locations and recent power factor readings for the Hanford site and selected metering locations. We will also need the most recent SKM data files on the 230 KV loop to access power availability and the impacts of adding active power factor correction to A6. I am just giving you a heads up on the most urgent information.

Richard Ziegenbein
Washington River Protection Solutions
WTP Interface Management Lead
509 376 0991 office
775 247 8622 cell
1200 Jadwin (347) MS E6-30
Richland, WA 99352

From: Hache, Joseph M (Mike)
Sent: Thursday, May 06, 2010 11:45 AM
To: Ziegenbein, Richard S
Cc: Baker, Scott (EU); Takasumi, Dennis S
Subject: RE: Service Catalog Request: Electrical Utilities Services: KSR-4975

Richard,
Yesterday I called Central Engineering for status. Today I re-submitted the request. I am still directed to obtain estimate from certified estimator. Hopefully we will get something soon.
Thanks for your patience.

Joseph M Hache (Michael)
Electrical Utilities Design Authority
SI&U Engineering Team Lead
PH (509) 373-1853
Fax (509) 372-9734

From: Ziegenbein, Richard S
Sent: Wednesday, May 05, 2010 7:30 AM
To: Hache, Joseph M (Mike)
Subject: RE: Service Catalog Request: Electrical Utilities Services: KSR-4975

Good Morning Mike,

Please advise the status of the estimate.

Email from the Hanford 230kV System Operator stating no PF penalty

Richard Ziegenbein
Washington River Protection Solutions
WTP Interface Management Lead
509 376 0991 office
775 247 8622 cell
1200 Jadwin (347) MS E6-30
Richland, WA 99352

From: Hache, Joseph M (Mike)
Sent: Monday, April 26, 2010 12:59 PM
To: Ziegenbein, Richard S
Cc: Parker, Ronald D Jr; Baker, Scott (EU)
Subject: FW: Service Catalog Request: Electrical Utilities Services: KSR-4975

I have prepared a preliminary estimate, however have been instructed to obtain estimate from certified – qualified "estimators". In process to obtain estimator. Will advise when I get an response.

Joseph M Hache (Michael)
Electrical Utilities Design Authority
SI&U Engineering Team Lead
PH (509) 373-1853
Fax (509) 372-9734

From: Ziegenbein, Richard S
Sent: Friday, April 23, 2010 10:13 AM
To: Hache, Joseph M (Mike)
Subject: FW: Service Catalog Request: Electrical Utilities Services: KSR-4975

Hi Mike,

Will you be able to provide me the estimate numbers early next week? If I remember from a previous discussion you thought you might be able to get the estimate to me this week.

Richard Ziegenbein
Washington River Protection Solutions
WTP Interface Management Lead
509 376 0991 office
775 247 8622 cell
1200 Jadwin (347) MS E6-30
Richland, WA 99352

From: Ziegenbein, Richard S
Sent: Monday, April 12, 2010 3:41 PM

To: ^Electrical Utilities Work Management
Subject: RE: Service Catalog Request: Electrical Utilities Services: KSR-4975

We are looking for MSA to provide an estimate of the cost to provide the services called for. Does this require a CACN for preparing only an estimate?

Richard Ziegenbein
Washington River Protection Solutions
WTP Interface Management Lead
509 376 0991 office
775 247 8622 cell
1200 Jadwin (347) MS E6-30
Richland, WA 99352

From: ^Electrical Utilities Work Management
Sent: Monday, April 12, 2010 11:05 AM
To: Ziegenbein, Richard S
Cc: Hache, Joseph M (Mike); ^Electrical Utilities Work Management
Subject: FW: Service Catalog Request: Electrical Utilities Services: KSR-4975

Richard,

We have received your service request and it will be forwarded onto Engineering shortly. Unfortunately the CACN you provided is not a valid MSA CACN and we require a valid number to proceed with the request. This number should start with a "4". Please verify what the correct number should be and forward to us at this email address.

Thank you,

Electrical Utilities Work Management Group

From: ^Mission Service Desk
Sent: Monday, April 12, 2010 10:34 AM
To: ^Electrical Utilities Work Management
Subject: Service Catalog Request: Electrical Utilities Services: KSR000000004975

Service Catalog Request Received

Request ID: KSR000000004975
Request Submitted By: Ziegenbein, Richard S

Service Category: Electrical Utilities Services
Service Requested: Engineering

Requester Information:
Name: Ziegenbein, Richard S
Hanford ID: h6510231
Phone #: (509)376-0991
Location: 1200JADWIN/347/RCHC
Email Address: Richard_S_Ziegenbein@rl.gov

CACN: 200841

COA: AA00

Work Location: 2101M/120/200E

Request Details:

MSA SUPPORT EFFORTS
MSA is requested to provide the following services in support of the Analysis of Power Delivery to the WTP project. The project is estimated to begin in April 2010 and complete in September 2010. Detailed discussions have been held

OMNICABLE

Attachment 9

(800) 292-OMNI

Overhead Line Ampacity Chart

ACSR

Aluminum Conductor, Steel Reinforced, Bare

ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW

URS STUDY #: 17-05-110-001 Rev 0

WRPS Report #: RPP-RPT-46992 Rev 0

Conductor:
- Aluminum alloy 1350-H19 wires concentrically stranded around a steel core
- Core wire for ACSR is available with class A,B, or C stranding

Insuluation:
- None

Jacket:
- None

Application
- Used as bare overhead transmission cable and as primary and secondary distribution cable
- ACSR offers optimal strength for line design
- Variable steel core stranding enables desired strength to be achieved without sacrificing ampacity

Standards/Specifications
- ASTM - B-230 Aluminum Wire, 1350-H19 for Electrical Purposes
- ASTM - B-231 Aluminum Conductors, Concentric-Lay-Standed
- ASTM - B-232 Aluminum Conductors, Concentric-Lay-Stranded, Coated Steel Reinforced

Part #	Size AWG/KCM	Standing (Al/Stl)	Overall Diameter	Wgt./1000'		Rated Strgth/lbs.	Amps*
				Alum	Total		
Turkey	6	6/1	0.198	24.5	36.1	1190	105
Swan	4	6/1	0.25	39	57.4	1860	140
Swanate	4	7/1	0.257	39	67	2360	140
Sparrow	2	6/1	0.316	62	91.3	2850	184
Sparate	2	7/1	0.325	62	106.7	3460	184
Robin	1	6/1	0.355	78.2	115.2	3550	212
Raven	1/0	6/1	0.398	98.6	145.2	4380	242
Quail	2/0	6/1	0.447	124.3	183.1	5310	276
Pigeon	3/0	6/1	0.502	156.8	230.9	6620	315
Penguin	4/0	6/1	0.563	197.7	291.1	8350	357
Waxwing	266.8	18/1	0.609	250.4	290	6880	449
Partridge	266.8	26/7	0.642	251.7	367	11300	457
Ostrich	300	26/7	0.68	283	413	12700	492
Merlin	336.4	18/1	0.684	315.8	365	8680	519
Linnet	336.4	26/7	0.72	317.3	463	14100	529
Oriole	336.4	30/7	0.741	318.1	527	17300	535
Chickadee	397.5	18/1	0.743	372.5	431	9940	576
Brant	397.5	24/7	0.772	374.9	512	14600	584
Ibis	397.5	26/7	0.783	375	547	16300	587
Lark	397.5	30/7	0.806	375.9	623	20300	594
Pelican	477	18/1	0.814	447.8	518	11800	646
Flicker	477	24/7	0.846	450	615	17200	655
Hawk	477	26/7	0.858	450	657	19500	659
Hen	477	30/7	0.883	451	747	23800	666
Osprey	556.5	18/1	0.879	522	604	13.7	711
Parakeet	556.5	24/7	0.914	525	717	19.80	721
Dove	556.5	26/7	0.927	525	766	22600	726
Eagle	556.5	30/7	0.953	526	872	27800	734
Peacock	605	24/7	0.953	571	779	21600	760
Squab	605	26/7	0.966	571	833	24300	765
Wood Duck	605	30/7	0.994	572	948	28900	774
Teal	605	30/19	0.994	572	939	30000	773
Kingbird	636	18/1	0.94	597	691	15700	773
Swift	636	36/1	0.93	597	644	13690	769
Rook	636	24/7	0.978	600	819	22000	784
Grosbeak	636	26/7	0.99	600	875	25000	789
Scoter	636	30/7	1.019	601	996	30400	798
Egret	636	30/19	1.019	601	988	31500	798
Flamingo	56.6	24/7	1	629	859	23700	807
Gannet	656.6	26/7	1.014	628	917	26400	812
Stilt	715.5	24/7	1.036	675	922	25500	844
Starling	716.5	26/7	1.051	675	985	28400	849
Redwing	715.5	30/19	1.081	676	1111	34600	859
Coot	796	36/1	1.04	747	805	16710	884
Cuckoo	795	24/7	1.092	749	1024	27900	901

Drake	795	26/7	1.108	750	1094	31500	907
Torn	795	45/7	1.063	750	896	22100	887
Condor	795	54/7	1.092	750	1024	28200	889
Mallard	795	30/19	1.14	752	1235	38400	918
Ruddy	900	45/7	1.131	849	1015	24400	958
Canary	900	54/7	1.162	849	1159	31900	961
Rail	954	45/7	1.165	900	1075	25900	993
Cardinal	954	54/7	1.196	900	1229	33800	996
Ortolan	1033.5	45/7	1.212	975	1165	27700	1043
Curlew	1033.5	54/7	1.245	975	1329	36600	1047
Bluejay	1113	45/7	1.259	1050	1255	29800	1092
Finch	1113	54/19	1.293	1055	1431	39100	1093
Finch	1113	54/19	1.293	1055	1431	39100	1093
Bunting	1192.5	45/7	1.302	1125	1344	32000	1139
Grackle	1192.5	54/19	1.333	1130	1533	41900	1140
Bittern	1272	45/7	1.345	1200	1434	34100	1184
Pheasant	1272	54/19	1.382	1206	1635	43600	1187
Dipper	1351.5	45/7	1.386	1275	1522	36200	1229
Martin	1351.5	54/19	1.424	1281	1737	46300	1232
Bobolink	1431	45/7	1.427	1350	1613	38300	1272
Plover	1431	54/19	1.465	1357	1840	49100	1275
Nuthatch	1510.5	4517	1.466	1425	1702	40000	1313
Parrot	1510.5	54/19	1.505	1432	1942	51700	1318
Lapwing	1590	45/7	1.504	1500	1792	42200	1354
Falcon	1590	54/19	1.545	1507	2044	54500	1359
Chukar	1780	84/19	1.602	1687	2074	51000	1453
Bluebird	2156	84/19	1.762	2044	2512	60300	1623
Kiwi	2167	72/7	1.735	2054	2303	49800	1607

*Conductor temp of 75 degrees Celcius, ambient temp of 25 degrees Celcius, emissivity 0.5, wind 2ft./sec., in sun. Note: The data shown is approximate and subject to standard industry and manufacturer tolerances.

June 21, 2010

Attachment 9

Overhead Line Ampacity Chart

ANALYSIS OF POWER DELIVERY TO THE
WTP TO ACHIEVE A MINIMUM OF 70MW
URS STUDY #: 17-05-110-001 Rev 0
WRPS Report #: RPP-RPT-46992 Rev 0

Meeting Minutes

Chairperson: Richard Ziegenbein

Meeting: June 14, 2010, 1100 hours

Location: 2440 Stevens Center Drive, 2701 Conference Room

Purpose: Monthly Status Meeting – Analysis of Power Delivery to WTP

Prepared by: Richard Ziegenbein

1. **Meeting Attendees**

Mazen Al-Wazani	Russell Harwood	Martin Wheeler
Corbun Babel	Randall Krekel	Jeremy Wilkens
Ernie Hamm	Zak Schatz	Richard Ziegenbein

2. **Project Status** –The Phase I report is still on track for June 30, 2010 transmittal to ORP. The deliverable of the SKM analysis of the 230 KV system is at risk. The SKM report has not been made available due to ongoing negotiation efforts with MSA on the level of support required for the entire analysis effort. Richard discussed an option of performing a maximum capacity calculation of the 230 KV Hanford system and comparing the result with the projected loads on the 230 KV system. Mazen indicated that it is critical to have the SKM analysis of the 230kV system that will include the load flow, short circuit and voltage drop analysis. He also, indicated the report will not be completed without the SKM analysis including estimate of the tank farm loads and future loads. He also, indicated if WRPS at risk of meeting the June 30, 2010 or not having complete report including SKM analysis, WRPS needs to communicate that with a letter to DOE-ORP for any changes to the deliverable required by WRPS letter WRPS-1000326 R2. Mazen also indicated that is critical to have MSA and BNI to review the report and provide their comments formally. Randy Krekel informed the group that DOE has negotiated a Tier 1 billing structure with BPA on the first 92 MW of load. 70 MW covers a previously projected WTP load. 22 MW covers a previously projected Hanford Site wide load.
   Update – On June 21, 2010 MSA accepted WRPS contract #36523, release 38 in technical support of the Analysis of Power Delivery to WTP report. On June 21, 2010 MSA was tasked by WRPS to provide the SKM files, impedance drawing and review comments on the Phase I report.

3. **Project Schedule** – An updated project schedule, dated June 14, 2010 was presented by Richard to Mazen. A revised copy of the schedule was e-mailed to Mazen the afternoon of June 21, 2010.

4. **Review of Phase I of the Report** – The Phase I report has undergone an extensive internal URS review. Richard passed out CDs that contained files of the Phase I Report, attachments and referenced documents. Richard asked everyone to provide review comments by using "track changes" and to e-mail the document to him by close of business Friday, June 18, 2014.
   Update – Review Comments were received from: DOE-RL on June 15, 2010 via track changes, DOE-ORP provided most of their comments on June 18, 2010, 8 more additional comments were provided on June 21, 2010 via the Review Comment Record (RCR) form A6400-090.1 and WRPS Central Engineering on June 21, 2010 via track changes. WRPS will disposition the review comments via the RCR process and issue the Phase I Report as a final PE stamped document on June 30, 2010.

5. **Review of Options** – Richard briefly described the eight options contained within the report. Three of the options are highly rated and key features of each option were presented to the group. See attachment for details on the eight options.

6. **Requested WTP Documents** – The WTP documents requested by Richard in Thursday, May 27, 2010, were provided by Mazen in a CD on Wednesday, June 2, 2010. The CD included copies of the following documents:
   - 24590-BOF-E1-MVE-00002, Rev 9, Switchgear Building 13.8KV MVE-SWGR-87001A & 87001B Single Line Diagram
   - 24590-BOF-E1-MVE-00003, Rev 8, Switchgear Building 13.8KV MVE-SWGR-87002A & 87002B Single Line Diagram
   - CCN 200152
   - CCN 196111
   - CCN 194415

Attachment: June 14, 2010 Meeting Sign-in Sheet

Listing of Eight Options Considered

Attachment 10

Meeting minutes: Provides the current 230kV system loading

June 14, 2010, 11:00 am

2440 Stevens Drive, 2701 Conference Room

NAME	SIGNATURE	E-MAIL ADDRESS	PHONE NUMBER
Al-Wazani, Mazen	mazen G. Al-Wazani	Mazen_G_Al-Wazani@orp.doe.gov	(509)376-4784
Babel, Corbun	Corbun Babel	Corbun_A_Babel@orp.doe.gov	(509)373-9281
Bruggeman, Jeffrey		Jeffrey_M_Bruggeman@orp.doe.gov	(509)373-8501
Brunson, Gary		Gary_E_Brunson@orp.doe.gov	(509)376-2477
Diediker, Janet		Janet_A_Diediker@orp.doe.gov	(509)372-3043
Harrington, Christopher		Chris_C_Harrington@orp.doe.gov	(509)376-1239
Harwood, Russell	Russell G Harwood	Russell_G_Harwood@orp.doe.gov	(509)376-2348
Krekel, Randall	Randall N Krekel	Randall_N_Krekel@rl.gov	(509)376-4264
Olsen, Gary		Gary_B_Olsen@orp.doe.gov	(509)438-4707
Hache, Mike		Joseph_M_Mike_Hache@rl.gov	(509)373-1853
Hamm, Earnest	Earnest Hamm	Earnest_R_Hamm@rl.gov	(509)372-0310

Wheeler, Martin		Martin_Wheeler@rl.gov	(509)376-2099
Wilkins, Jeremy		Jeremy_D_Wilkins@rl.gov	(509)551-7917
Schatz, Zak		Zakary_M_Schatz@rl.gov	(509)376-6411
Ziegenbein, Richard		Richard_S_Ziegenbein@rl.gov	(509)376-0991

EIGHT OPTIONS CONSIDERED

RECOMMENDED OPTIONS

Replace transformers with 100 MVA transformers
Directly feed WTP Building 87 switchgear
Does not meet ICD 11 interface boundaries
$10.5 M 2 years

Replace transformers with 100 MVA transformers
Replace switchgear with two 4,000 A switchgear
Meets ICD 11 interface boundaries
$12.3 M 2 years

Procure spare 62 MVA transformer
Utilize IEEE Std C57.91 loading
Does not meet single transformer loading
$1.5 M 1 year

OPTIONS NOT RECOMMENDED

Replace transformers with 100 MVA transformers
Add two 3,000 A switchgear
Build second A6 substation building
$18.4 M 2 years

Add two 62 MVA transformers
Replace switchgear with two 4,000 A switchgear
Build second A6 substation building
No cost estimate prepared due to cost of second building

Add two 62 MVA transformers
Add two 3,000 A switchgear
Build second A6 substation building
No cost estimate prepared due to cost of second building

Add 62 MVA transformer
Build second A6 substation building
No cost estimate prepared due to cost of second building

Existing A6 Substation
Two 62 MVA transformers
Two 3,000 A switchgear
Utilize IEEE Std C57.91 loading
Does not meet single transformer loading

Attachment 11
Handford 230kV System Projected Loads

Baseline Case

	Project Name	Projected Electrical Loading (kVA)	Source Info	Powered From Substation	Point of Contact	Comments
1	Tank Farm Upgrades (Waste Feed Delivery and Safe Storage)	13,605	Ref. #22	A8	Mike Leonard	RPP-5228 Rev 1 Table 2.5 (used bounding Assessment 4a loading) & Table 2.6
2	Integrated Disposal Facility	0	Att. #10	A8		This facility is currently operating and is part of the 22MW accounted for in the existing Hanford 230kV system loads.
3	Interim Hanford Storage Facility	445	Att. #14	A8	Paul Robinson	
4	Secondary Waste/Effluent Treatment Facility (ETF) Upgrades	665	Ref. #23	A8	Thomas May	1,000 Amp circuit with a 80% demand factor
5	Second LAW	46,000	Att. #13	A6		Apportioned, based off of the existing LAW and BOF Electrical Loads times 2 (Second LAW 2X the Size of the Current LAW)
6	Wiped Film Evaporator Mobile Unit	0		A8	Ronald Yanochko	This is a mobile unit. A mobile generator will be utilized to provide electrical power to this unit.
7	B/T Farm Special Waste Retrieval and Packaging	8,750	Att. #15	A8	Allan (Rick) Tedeschi	
8	Tank Waste Operations Center	8,325	Att. #16	A8	Paul Robinson	Based off of 18.5VA/sqft per IEEE 241 2.6 Example Sample Partial Load Calculation for an Office Building and 450,000 sqft.
9	Aluminum Reduction Facility (ARF)	250	Att. #12	A6	Terry Sams	
	A6 Substation Subtotal	46,250				
	A8 Substation Subtotal	31,790				
	Total	78,040				

Attachment 11
Handford 230kV System Projected Loads

Alternative Case

	Project Name	Projected Electrical Loading (kVA)	Source Info	Powered From Substation	Point of Contact	Comments
1	Tank Farm Upgrades (Waste Feed Delivery and Safe Storage)	13,605	Ref. #22	A8	Mike Leonard	RPP-5228 Rev 1 Table 2.5 (used bounding Assessment 4a loading) & Table 2.6
2	Integrated Disposal Facility	0	Att. #10	A8		This facility is currently operating and is part of the 22MW accounted for in the existing Hanford 230kV system loads.
3	Interim Hanford Storage Facility	445	Att. #14	A8	Paul Robinson	
4	Secondary Waste/Effluent Treatment Facility (ETF) Upgrades	665	Ref. #23	A8	Thomas May	1,000 Amp circuit with a 80% demand factor
5	East Supplemental Pretreatment Facility (SCIX & RMF)	196	Att. #17	A8	Thomas May	
6	East Supplemental Treatment Facility I (FBSR)	2,250	Att. #17	A8	Jeffrey Filip	Assumes electric steam generators
7	East Supplemental Treatment Facility II (FBSR)	2,250	Att. #17	A8	Jeffrey Filip	Assumes electric steam generators
8	East Post Supplemental Treatment Encapsulation	3,000	Att. #12	A8	Terry Sams	
9	West Supplemental Pretreatment Facility (SCIX & RMF)	196	Att. #17	A8	Thomas May	
10	West Supplemental Treatment Facility (FBSR)	2,250	Att. #17	A8	Jeffrey Filip	Assumes electric steam generators
11	West Post Supplemental Treatment Encapsulation	3,000	Att. #12	A8	Terry Sams	
13	Wiped Film Evaporator Mobile Unit	0		A8	Ronald Yanochko	This is a mobile unit. A mobile generator will be utilized to provide electrical power to this unit.
14	B/T Farm Special Waste Retrieval and Packaging	8,750	Att. #15	A8	Allan (Rick) Tedeschi	
15	Tank Waste Operations Center	8,325	Att. #16	A8	Paul Robinson	Based off of 18.5VA/sqft per IEEE 241 2.6 Example Sample Partial Load Calculation for an Office Building and 450,000 sqft.
	A8 Substation Total	44,933				

Note: If value was given in terms of MW a .8 pf was assumed for conversion to MVA.

ARF - Aluminum Reduction Facility
ETF - Effluent Treatment Facility
EWRF - East Area Waste Receiver Facility
FBSR - Fluidized Bed Steam Reformer
IDF - Integrated Disposal Facility
RMF - Rotary Micro-filtration
SCIX - Small Column Ion Exchange
WFE- Wiped Film Evaporator

Ziegenbein, Richard S

From: Sams, Terry L
Sent: Monday, June 28, 2010 1:39 PM
To: Sams, Terry L; Ziegenbein, Richard S
Subject: RE: ARF FULL SCALE ELECTRICAL LOADS

ARF is 200kW

Terry L. Sams, **PMP**
Manager, Technology and Development
WTP Support
business: 509-376-4653
cell: 509-619-6502
fax: 509-373-3833
washington river protection solutions

From: Sams, Terry L
Sent: Monday, June 28, 2010 12:35 PM
To: Ziegenbein, Richard S
Subject: RE: ARF FULL SCALE ELECTRICAL LOADS

The power required for each of these processes is identified below:

RMF & SCIX –	0.048 Mega Watts	60 KVA
FBSR -	0.8 Mega Watts	1.0 MVA
Melter -	2.4 Mega Watts (Nominal) 3 Mega Watts (Design Basis)	3.0 MVA
TOTAL	**3.248 MW**	

The assumption may be that we deploy three total RMF/SCIX/FRSR units and the total power would triple for that scenario. Hence for the total I would use **5.5 MW**. I am still putting an estimate together for ARF.

Terry L. Sams, **PMP**
Manager, Technology and Development
WTP Support
business: 509-376-4653
cell: 509-619-6502
fax: 509-373-3833
washington river protection solutions

From: Ziegenbein, Richard S
Sent: Thursday, June 24, 2010 4:17 PM
To: Sams, Terry L
Subject: ARF FULL SCALE ELECTRICAL LOADS

Terry,

You have been recommended as a ARF knowledgeable person.

As we discussed earlier, I am pulling together the electrical loads for the power study. We are having a problem coming up with the project load by ARF. Any rough ideas on what it maybe or how to develop it?

Richard Ziegenbein
Washington River Protection Solutions
WTP Interface Management Lead
509 376 0991 office
775 247 8622 cell
1200 Jadwin (347) MS E6-30
Richland, WA 99352

Attachment 12

Meeting minutes: Provides the ARF Loading

ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW
URS STUDY #: 17-05-110-001 Rev 0
WRPS Report #: RPP-RPT-46992 Rev 0

WTP Facilities	Power (MW) (A)	PF (B)	Power (MVA) (C)=(A)/(B)	% Total Load (D)	Power (MVA) (E)=(C)*70/55.1	The 4 Process Facilities % Electrical Loading (F)
BOF	21.1	0.916	23.08	42%	29.3	
LAW	8.8	0.916	9.60	17%	12.2	30%
LAB	1.8	0.916	1.92	3%	2.4	6%
HLW	7.7	0.916	8.36	15%	10.6	26%
PTF	11.1	0.916	12.16	22%	15.4	38%
Cable Loss	0.0	0.916	0.01	0%	0.0	
Total	50.5		55.1	100%	70.0	100%

Note: Column (A) information is taken from Ref. #1, Section 8.1.2

Proportioned 2nd LAW

First LAW=	12.2	MVA	
Proportioned BOF=	8.8	MVA	=29.3*30%
Total	21.0	MVA	

2nd LAW to be twice as Big as First LAW

Multiplier=	2	
Total 2nd LAW Electrical Load Demand=	42	MVA

Attachment 14

Email: Provides the Interim Hanford Storage Facility Loading

From: Robinson, Paul A
To: Ziegenbein, Richard S
Subject: Electrical Demand for IHSF
Date: Thursday, June 17, 2010 1:21:58 PM
Attachments: image001.png
IHSF.pdf

Richard,

2000 Canister Vault
2 x 20 HP fans operating on the supply AHU 30 kW
1 x 75 HP fan providing exhaust filtration 56 kW
Total 86 kW

4000 Canister Module
2 x 40 HP fans operating on the supply AHU 60 kW
1 x 200 HP fan providing exhaust filtration 210 kW
Total 270 kW

RPT-ISF-EG-0004, Rev 1, Table 11 in the attachment by Energy Solutions' Ken Bentley.

Cost is derived by multiplying Duration in months x power consumption x 24 hours per day x 30 days in month x $.031 per Kwhr.

First line (May 2018 – Jan 2024):
i.e. 68 months x 30 days/month x 24 hrs/day x 56 Kw x 0.031 = $84995

I checked the months duration using http://www.timeanddate.com/date/duration.html. All of the months duration in Table 11 check out correctly according to my calculation.

This estimate does not include the crane's power usage.

The cranes for the Modular (Baseline) facility are:

Truck bay Crane: 60 Ton
Inspection Hot Cell Crane: 5 Ton
Store Crane: 6 Ton (places IHLW canisters in storage location)

Thanks,

Paul Robinson

washington river protection solutions
Engineer-Project
Richland, Washington 99352
office (509)376-2135

From: Tedeschi, Allan R (Rick)
To: Ziegenbein, Richard S
Subject: FW: CH-TRUM Electrical Power Needs
Date: Thursday, June 10, 2010 12:14:51 PM

From: Tedeschi, Allan R (Rick)
Sent: Thursday, January 25, 2007 11:27 AM
To: Hamm, Earnest R
Subject: FW: CH-TRUM Electrical Power Needs

Ernie,

I was only off by a factor of 5.

One dryer running = 5.5 MW
Two Dryers running = 6.5 MW

This estimate was before we added the scope for characterization, storage, and shipping. The ROM power draw for that facility is 0.5 MW, so we are looking for a range of 6 - 7 MW starting in April 2013. This does not include the power draw for retrieval systems which I do not have. Estimate one standard vacuum retrieval system will be operating in parallel with all of my other equipment during the same time period.

Rick

From: Holm, Melissa J
Sent: Tuesday, September 05, 2006 3:16 PM
To: Thien, Michael G
Cc: Tedeschi, Allan R (Rick)
Subject: RE: CH-TRUM Electrical Power Needs

Mike,

When we were looking at the possibility of having a second dryer operating simultaneously, the estimate was 6.5 MW. The last decision was to go with one dryer for the project.

Thanks,

Melissa

From: Thien, Michael G
Sent: Tuesday, September 05, 2006 1:23 PM
To: Holm, Melissa J
Cc: Tedeschi, Allan R (Rick)
Subject: RE: CH-TRUM Electrical Power Needs

Melissa,

Are there plans to add an additional dryer? If so what would you estimate the new power needs at?

Mike

From: Holm, Melissa J
Sent: Friday, September 01, 2006 11:14 AM
To: Thien, Michael G
Cc: Tedeschi, Allan R (Rick)
Subject: CH-TRUM Electrical Power Needs

Mike,

The last estimate for electrical power needs for the CH-TRUM Project were 5.5 MW. This estimate was for the use of only one dryer.

Let me know if you have any more questions.

Thanks,

Melissa

From: Robinson, Paul A
To: Ziegenbein, Richard S
Subject: Department of Energy analysis of options to upgrade power supply in the 200 East Area
Date: Wednesday, June 09, 2010 7:16:30 AM
Attachments: image001.png

Richard,

TWOC complex buildings will be divided into two phases. The 1st phase is 168,750 SF and the 2nd is 281,250 SF. The total of both phases are 450,000 SF.

Thanks,

Paul Robinson
washington river protection solutions
Engineer-Project
Richland, Washington 99352
office (509)376-2135

SCIX, RMF, FBSR, (x) secondary waste

Colosi, Kristin A

2x2 Exp to WESTPAC supplement

From: Filip, Jeffrey E
Sent: Wednesday, May 26, 2010 12:19 PM
To: Colosi, Kristin A
Cc: May, Thomas H (Tom)
Subject: FW: POWER REQUIREMENTS

Kris
If we use electricity for the steam generation, then it's an additional 900kW/hour, or a total of **1800kW/hour**.

From: Filip, Jeffrey E
Sent: Wednesday, May 26, 2010 12:11 PM
To: May, Thomas H (Tom)
Subject: FW: POWER REQUIREMENTS

Fluidize Bed steam Reforming

Tom
Are your rates below per hour?

From: Filip, Jeffrey E
Sent: Wednesday, May 26, 2010 11:48 AM
To: Colosi, Kristin A
Cc: 'Pat Bacala'; May, Thomas H (Tom)
Subject: FW: POWER REQUIREMENTS

Sho w/ Thor

Kris
In discussion with Pat Bacala, the following power will be required for the FBSR:
1) 1400 kW/hour during start up of system
2) 900 kW/hour during normal operation

Tom MAX

Assumes:
1) Use existing 98" Areva design as basis for power consumption
2) Combustion source (ex. Natural gas) to heat boilers for steam generation at Hanford

---

From: May, Thomas H (Tom)
Sent: Wednesday, May 26, 2010 11:07 AM
To: Filip, Jeffrey E
Subject: POWER REQUIREMENTS

Jeff,

When you get the FBSR power requirements, please add and send to Kris.

Tom

SCIX/RMF (WESTPAC EAST + Supplemental Treat Pre Treatment

power requirements = 75kW/82 kW = 157 kW/hr /system

.RPP-RPT-37551

Secondary Waste

Attachment 17

Email: Provides the Supplemental Facility's Loading

1

ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW
URS STUDY #: 17-05-110-001 Rev 0
WRPS Report #: RPP-RPT-46992 Rev 0

Per HNF-26914 R0: "The existing ETF electrical service originates from two 13.8 kV – 480Y/277 V station service transformers that supply two main switchgear units. A new 1000A frame, 1000A trip circuit breaker will be installed in the new building addition for the solidification treatment unit."

Based on this it appears that the power available currently to ETF is enough to support the addition of the secondary treatment facility.

Attachment 17

Email: Provides the Supplemental Facility's Loading

ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW

URS STUDY #: 17-05-110-001 Rev 0

WRPS Report #: RPP-RPT-46992 Rev 0

APPENDIX B

REVIEW COMMENT RECORDS ON REVISION B OF URS STUDY

- P. Zavadivker BNI number of pages 16
- C. Chan BNI number of pages 8
- M. Al-Wazani ORP number of pages 19
- R. Krekel RL number of pages 1
- E. Hamm WRPS number of pages 2

REVIEW COMMENT RECORD (RCR)

1. Date	2. Review No.
06/22/2010	
3. Project No. Project Number	Page 1 of 2

5. Document Number(s)/Title(s)	6. Program/Project/Building Number	7. Reviewer	8. Organization/Group	9. Location/Phone
Analysis of Power Delivery to WTP Study Number: 17-05-110-001		Phil Zavadivker	BNI/ WTP Oakland	Oakland, CA

17. Comment Submittal Approval	10. Agreement With Indicated Comment Disposition(s)	11. CLOSED
Date / Organization Manager (optional) (print and sign)	7/8/10 Date Phil Zavadivker Reviewer/Point of Contact (print and sign) Jeremy Wilkins Author/Originator (print and sign)	7/8/10 Date Phil Zavadivker Reviewer/Point of Contact (print and sign) Jeremy Wilkins Author/Originator (print and sign)

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
1	General				Option 5 – Swing Bus (transformer), does not technically meet this requirement and was formally rejected as such. However, as you are aware, a swing bus effectively eliminates the criteria for 100% WTP operation on a single transformer; thus this should still be an option for consideration. However, there was insufficient space in the A6 substation switchgear building to add the two new vertical sections necessary to fully implement a swing transformer. This drove the need for a second switchgear building, relocating one of the existing switchgear, 3 new bus duct (to maintain the current design configuration), and implementing approximately 2/3 of the future 230kV expansion design. Because of this, it was deemed more cost effective to implement Option 4, which has the added benefit of essentially not changing the fault current.	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
2	General				Option 6 – Warehoused Spare, this option did not technically meet DOE's requirement for 70MW @ 91.6% pf on a single A6 transformer. Yet, this option is a relatively low cost method of maintaining plant operations, with limited down time. As you suggested, additional steps can be taken to minimize the amount of WTP operations down time due to a transformer failure.	
3	General				In short, if an option could NOT provide a minimum of 70MW @ 91.6% pf from a single A6 substation transformer it was rejected. Additionally, if the ROM total install cost was going to substantially exceed Option 1's ROM TIC, then the cost and schedule estimates were not developed further.	
4	General				DOE requested viable options for providing a minimum of 70MW @ 91.6% pf to the WTP while the A6 substation is operating on a single transformer.	
					Note to file: Signatures not obtained from BNI due to non-mandatory nature of BNI comments. See attached July 8, 2010 e-mail.	

From: Wilkins, Jeremy D
To: Ziegenbein, Richard S
Subject: FW: Bechtel"s Comments on the URS Study Titled, "ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW (76.4MVA)", 17-05-110-001 Rev 0
Date: Thursday, July 08, 2010 7:29:11 AM

Richard,

BNI forwarded the same comments with the CCN# 217014. I just copied and pasted the original responses (the responses I sent to you yesterday) into this email.

Jeremy Wilkins, P.E.
Electrical Engineer
Washington River Protection Solutions/URS
Email: Jeremy_D_Wilkins@rl.gov
Office: 509-376-1041
Cell: 509-551-7917

From: Chan, Charles M [mailto:cmchan@bechtel.com]
Sent: Tuesday, July 06, 2010 1:07 PM
To: Wilkins, Jeremy D; WTP PDC
Cc: Lucke, Gary; Chuang, Chet; Claghorn, Ronald; Pell, Michael; Tam, Thomas; Al-Wazani, Mazen G; Zavadivker, Phil
Subject: RE: Bechtel's Comments on the URS Study Titled, "ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW (76.4MVA)", 17-05-110-001 Rev 0

Jeremy, **CCN# 217014**
Message is resent with CCN number added.

PDC,
Please file this email under the CCN number 217014. Thanks.

Charles
Tel. 509-371-3085

From: Chan, Charles M
Sent: Tuesday, July 06, 2010 9:15 AM
To: 'Wilkins, Jeremy D'
Cc: Lucke, Gary; Chuang, Chet; Claghorn, Ronald; Pell, Michael; Tam, Thomas; 'Al-Wazani, Mazen G'; Zavadivker, Phil
Subject: RE: Bechtel's Comments on the URS Study Titled, "ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW (76.4MVA)", 17-05-110-001 Rev 0

Jeremy,

Since the URS Study is commenced outside of WTP's scope, we are not in a position to have "mandatory" comments. The following are our comments/suggestions for your consideration.

(1) The report refers to the WTP Interface Control Document (ICD) description on the power requirement and recommends a change on the description from what was "for planning purpose" to "For the purpose of design" (see para. VI.A.1.b and XIII.A). If implemented, this would mean a Contract requirement change to WTP. We suggest that this part of the recommendation be removed.

The study is not concerned with contract scope only on technical merit. The study makes this recommendation based off of IEEE 141 section 2.4.1.4 for future operational load growth. Additionally, DOE has essentially already directed the study's recommendation in CCN 194415 and CCN 200152.

(2) Para. XIII.B "The Fifth Feeder is not recommended as a means to supply 70 MW of electrical power to the WTP .....in conjunction with any other option presented in this study."
We noticed that the study does not consider an possible option of using a combination of changing the existing 37/50/62MVA transformers to 45/60/75MVA (with the existing 13.8 kV 3000A bus switchgear in A6 substation unchanged) plus the Fifth Feeder option which will meet the total 70 MW requirement. We suggest that you add this option in the study.

Yes, I concur with the comment other; however, with the approximate $5M price tag for the fifth feeder option, it was viewed as more cost effective to upgrade the A6 substation to adequately carry the entire 70MW of electrical load.

(3) Para. VI.B.1.d.(2)(b)(i) "This is not a recommended normal electric plant line-up."
The switching between the different sources are at the 87002A and 87003 buses. The selection between the two different sources does not appear to have any different results. We suggest that this recommendation be reconsidered.

The statement, "This is not a recommended normal electric plant line-up.", was deleted and this section of the study was revised accordingly. This recommendation was made based on the presumption that normal plant operations would either have all of the "A Train" loads running together or the "B Train" loads running together and that there would not be an operational intermixing of A loads with B loads, other than for maintenance or component failure.

(4) The URS Study recommends Option 7 as the preferred alternative. It is understood that URS doesn't view this option as the ideal solution, but only as the best of all available options, with none being perfect. However, following disadvantages for Option 7 warrant a closer look at this option.

- This option involves substantial changes in WTP facilities and , if implemented,

may result in cost and schedule impact to WTP.

- Will necessitate shared control of WTP switchgear with the 230kV utility operator, Mission Services Alliance (MSA) for the DOE
- Four incoming breakers at Bldg 87 switchgear 87001A(B) and 87002A(B) will be used as the point of interface ("PCC - Point of Common Coupling" in your report)
- Ditto for the utility metering point
- Bldg 87 switchgear will have to be modified for sub. A6 relaying
- Contract change will be required for modifications to Bldg 87 switchgear. Changes to contract documents (ICD, PDSA, BD, etc.) will be required
- Two 75kVA, 13kV feeds for a 208/120V service will have to be routed from Bldg 87 back to Sub A6
- Will result in increased short circuit contribution. Main transformer impedance will need to be re-calculated
- Main transformer differential (87) protection zone for the Main DOE transformers will have to include Bldg 87 incoming breakers (400-ft wire run)
- 400-ft-long 750kcmil cable leads, 4 x 6 x (3- 1/c-750), from A6 to Bldg 87 are left unprotected from overload
- Will create a safety concern in not being able to isolate the Main DOE transformers from within A6 sub for a fault, fire, repair or maintenance.
- Cables between Sub. A6 and Bldg 87 and the duct banks have been installed already.

The study was revised to indicate that both the WTP project and the Electrical Utility were not in favor of Option 7 due to these same disadvantages that are called out in the study.

(7) Option 6 (a third spare transformer stowed in the warehouse) got a “Fail” rating for Functionality because this Option supposedly wouldn’t meet the required minimum capacity limit. This option deserves a more careful consideration, perhaps being enhanced with some low-cost improvements, such as pre-installed transformer pad, pre-drilled anchor bolt holes, cable stubs, and ready-made cable connections to enable transformer replacement and installation under 48 hours. One alternative could be a completely pre-installed spare transformer with only the power connections remaining to be made. In fact, an overall task of having to maintain this spare transformer in a storage facility or having been already installed on the pad outdoors doesn’t look that much different. This will effectively represent a cross between Option 5 (swing transformer) and Option 6 (warehouse-stowed transformer). A review of Option 5 showed that a physical space for the third transformer was available; it is the 3,000A switchgear expansion that cannot be accommodated in the existing switchgear building and would require a new building.

Yes, this could be done. Yet, as was pointed out in the study, this doesn’t meet the basic 70MW during operations on a single transformer. Even if this was deemed acceptable, why would DOE want to implement this option, when approximately the same amount of money could be spent that fully complies with the study requirements of 70MW on a single transformer?

Charles
Tel. 509-371-3085

From: Chuang, Chet
Sent: Tuesday, June 29, 2010 5:05 PM
To: Wilkins, Jeremy D
Cc: Lucke, Gary; Chan, Charles M
Subject: RE: Bechtel's Comments on the URS Study Titled, "ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW (76.4MVA)", 17-05-110-001 Rev 0

Hi Jeremy,

I am out of town presently, and won't be back until 8/2/2010. Please coordinate with Charles Chan and Phil Z. directly on all technical issues related to the Study, please cc Gary and me.

Charles, Please provide a consolidated review comment (include Phil Z.) for the 70MW Load Study back to Jeremy, with a CCN, please cc Gary Lucke, Tom Tam, Phil and me.

Thanks,

Chet

From: Wilkins, Jeremy D [mailto:Jeremy_D_Wilkins@RL.gov]
Sent: Tue 06/29/2010 10:34 AM
To: Chuang, Chet
Cc: Lucke, Gary
Subject: Bechtel's Comments on the URS Study Titled, "ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW (76.4MVA)", 17-05-110-001 Rev 0

Chet,

Regarding WTP project's review of the Study, are there any comments that need to be addressed in the study prior to the study being formally issued to the client? In other words, does the WTP project have any mandatory comments?

Jeremy Wilkins, P.E.
Electrical Engineer
Washington River Protection Solutions/URS
Email: Jeremy_D_Wilkins@rl.gov
Office: 509-376-1041
Cell: 509-551-7917

From: Wilkins, Jeremy D
To: Ziegenbein, Richard S
Subject: BNI Comments on the A6 70MW Study
Date: Wednesday, June 23, 2010 8:09:51 AM
Attachments: Power_Options.doc

Attached is BNI's comments to the A6 70MW Study.

There are some good comments and thoughts, but nothing that would require the study to be revised.

Jeremy Wilkins, P.E.
Electrical Engineer
Washington River Protection Solutions/URS
Email: Jeremy_D_Wilkins@rl.gov
Office: 509-376-1041
Cell: 509-551-7917

From: Chuang, Chet [mailto:ccchuang@bechtel.com]
Sent: Tuesday, June 22, 2010 7:34 PM
To: Wilkins, Jeremy D
Cc: Zavadivker, Phil; Tam, Thomas; Chan, Charles M; Lucke, Gary
Subject: RE: Contact Information

Hi Jeremy,

Attached is a draft review comment from Phil Zavadivker (510) 271-3973, a Sr, Engineer with excellent experience at WTP Oakland Office.

I will be very busy with other issues tomorrow. Please coordinate with Phil directly for any technical issue, and cc me.

I won't be available at office (and Cell) between 6/24 and 7/30. Will return on 8/2.

Take care,

Chet
509-371-3543

Comments on
ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE 70MW
URS Study Number: 17-05-110-001

Please see Table below that summarizes the available options, as identified in the URS Study. Option 7 was recommended in the URS Study. I think Option 6 deserves a more careful consideration perhaps being enhanced with some low-cost improvements, such as pre-installed transformer pad, pre-drilled anchor bolt holes, cable stubs, and ready-made cable connections to enable transformer replacement and installation under 48 hours (estimated by URS as 1 month).

Description	OPTIONS									Notes
	Existing	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8	
-Transformers - DOE utility bus -WTP feeders	2x37/50/62 2x3,000A 4 feeders	2x60/80/100 2x4,000A 4 feeders	2x60/80/100 4x3,000A 4 feeders	4x37/50/62 2x4,000A 4 feeders	4x37/50/62 4x3,000A 4 feeders	3x37/50/62 Swing xfmr 2x3,000A 4 feeders	3x37/50/62 Warehouse 2x3,000A 4 feeders	2x60/80/100 No DOE SWGR 4 cable feeders	Each xfmr is rated for one load group only	
Cost	N/A	$12.3M	$18.4M	Not incl	$17.5M	Not incl	$1.5M	$10.5M	Not eval'd	
Schedule	N/A	2 yrs	2 yrs	Not incl	2 yrs	Not incl	1 month switchover	2 yrs		
Ranking: F/R Function: 1-Pass, 0-Fail Reliab: 3-Highest	N/A	1/3	1/3	Not incl	1/1	0/Not incl	0/Not incl	1/3		Opt. 5 & 6 rated Fail - which is unclear
Loss of a single x-mission line	No impact	No impact	No impact	No impact	No impact	No impact	No impact	No impact		
Loss of one DOE transformer	62MVA	96MVA	100MVA	96MVA	186MVA	124MVA	124MVA	95.6MVA		Opt. 6 listed as 62MVA - Fail, which is unclear
Loss of one DOE 13.8 kV swgr bus	72MVA	96MVA	172MVA	96MVA	186MVA	72MVA	72MVA	N/A		
Loss of one of four WTP 13.8 kV swgr buses	124MVA	143MVA	143MVA	143MVA	143MVA	124MVA	124MVA	143 MVA		
Advantages		Meet 70MW	Meet 70MW	Not incl	Meet 70MW Adds diversity and capacity	Not incl	Lowest cost	Meet 70MW requirement		
Disadvantages		See (1) below	See (2) below	Not incl	See (3) below	Not incl	Longer switchover time	See (4) below		

Notes to Table:

(1) Disadvantages for Option 1
- 4,000A SWGR isn't a standard design, requires fans
- Higher SC fault source contribution

(2) Disadvantages for Option 2
- Higher SC contribution
- Requires Second Utility Switchgear building
- Two more bus ducts
- Two more switchgear
- Breaking into existing bus duct

(3) Disadvantages for Option 4
- Higher SC fault current
- More materials & equipment, construction
- Breaking into existing bus duct
- Additional Swgr Bldg. is required
- Higher SC fault current

(4) Disadvantages for Option 7
- Will necessitate shared control of WTP switchgear with the 230kV utility operator, Mission Services Alliance (MSA) for the DOE
- Four incoming breakers at Bldg 87 switchgear 87001A(B) and 87002A(B) will be used as the point of interface (PCC - Point of Common Coupling)
- Ditto for the utility metering point
- Bldg 87 switchgear will have to be modified for sub. A6 relaying
- Contract change will be required for modifications to Bldg 87 switchgear. Changes to contract documents (ICD, PDSA, BD, etc.) will be required
- Two 75kVA, 13kV feeds for a 208/120V service will have to be routed from Bldg 87 back to Sub A6
- Will result in increased short circuit contribution. Main transformer impedance will need to be re-calculated
- * Main transformer differential (87) protection zone for the Main DOE transformers will have to include Bldg 87 incoming breakers (400-ft wire run)
- * 400-ft-long 750kcmil cable leads, 4 x 6 x (3- 1/c-750), from A6 to Bldg 87 are left unprotected from overload
- * Will create a safety concern in not being able to isolate the Main DOE transformers from within A6 sub for a fault, fire, repair or maintenance.
- * Cables between Sub. A6 and Bldg 87 and the duct banks have been installed already.

(*) Additional items added to the original URS list

Comments

1. Summary

1.1 The URS study is done very professionally, well supported technically, and reaches credible and reasonable conclusions. The following comments represent "talking points" for a follow-up discussion, rather than a "critique", in order to arrive at the solution, which will be the most appropriate economically and technically, and will provide reasonable assurance for accommodating future growth.

1.2 The URS Study recommends Option 7 as the preferred alternative. It is understood that URS doesn't view this option as the ideal solution, but only as the best of all available options, with none being perfect. However, a number of identified disadvantages for Option 7 (see highlighted in yellow above) warrant a closer look at this option, considering a $10.5M price tag, which will likely get even higher because of: (a) having to re-pull the already scheduled 400-ft-long 13.8kV cables in the duct banks between Bldg 87 and Sub. A6, and (b) having to include Bldg 87 13.8kV incoming breakers in the DOE transformers' differential protection zone.

1.4 Option 6 (a 3-rd spare transformer stowed in the warehouse) got a "Fail" rating for Functionality because this Option supposedly wouldn't meet the required minimum capacity limit. This conclusion isn't clear and needs to be discussed further (see 2.1 below) This option deserves a more careful consideration, perhaps being enhanced with some low-cost improvements, such as pre-installed transformer pad, pre-drilled anchor bolt holes, cable stubs, and ready-made cable connections to enable transformer replacement and installation under 48 hours. This practice of using a spare main transformer for a quick replacement is found acceptable by nuclear industry, see references in 2.3.

1.5 One alternative could be a completely pre-installed spare transformer with only the power connections remaining to be made. In fact, an overall task of having to maintain this spare transformer in a storage facility or having been already installed on the pad outdoors doesn't look that much different. This will effectively represent a cross between Option 5 (swing transformer) and Option 6 (warehouse-stowed transformer). A review of Option 5 showed that a physical space for the 3-rd transformer was available; it is the 3,000A switchgear expansion that cannot be accommodated in the existing switchgear building and would require a new building.

1.6 Ultimately, the study has arrived at a correct observation that a limiting factor for any increase in the installed transformer capacity is represented by the DOE 13.8kV utility switchgear in Sub A6. With a 3,000A continuous bus rating, this effectively limits the power flow through the bus to 71.7MVA. This limitation was attempted to be minimized in the study by: (a) increasing the bus rating to non-standard 4,000A (Option 3), providing additional 3,000 buses (Options 2 & 4) and ultimately by abandoning the entire 3,000A bus in Sub A6 (recommended Option 7).

1.7 We need to get a better understanding of a transfer logic used at the DOE substation (i.e., manual, auto, NC tie, etc.), but it appears from the diagram that a loss of a single source will result in either automatic, manual or continuous closeout of the tie breaker A364, assuming that both offsite sources carry adequate power capacity for two transformers.

1.8 The following discussion offers several talking points that should be discussed prior to reaching a conclusion.

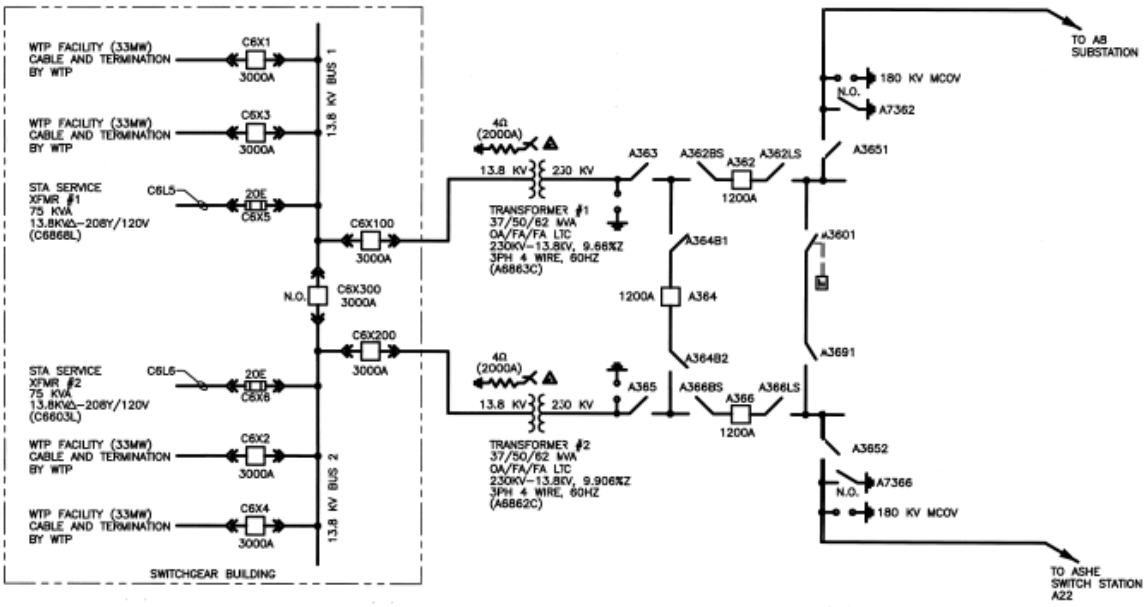
2. Discussion

2.1 Offsite power failure modes

I can see three possible offsite power failure mechanisms:

a) A loss of a single 230kV transmission line, either from A8 substation or ASHE Switch station A22.
b) A catastrophic DOE transformer failure (included are failures of 230kV components).
c) Failure of a 13.8kV utility bus or a cable feeder to WTP.

These failure mechanisms were addressed in the table above with available power capacity being identified against each failure. The most statistically meaningful failure mechanism is represented by (a) - A loss of a single source. However, with the 230kV circuit breaker configuration presently used at the A6 substation (see figure below), this failure appears being successfully mitigated. We need to get a better understanding of a transfer logic used at the substation (i.e., manual, auto, NC tie, etc.), but it appears from the diagram that a loss of a single source will result in either automatic, manual or continuous closeout of the tie breaker A364, assuming that both offsite sources carry adequate power capacity for two transformers.



2.2 Power Requirements

We need to agree on ground rules for maximum power demand estimate. Based on the latest Load Flow calc., Rev. E, the WTP maximum demand, including the assumed margins for future growth (2MW) and potential changes (0.5MW) is 52.998 MW or 57.86 MVA at 91.6% PF. ICD-11, rev. 4 (latest), 1.4.2, used 15% contingency, 15% design growth, and 5% losses margins to jack up the original power estimate of 41MW to 55 MW [41 x (1.15+1.15+1.05] =55MW. Therefore, it's not reasonable to continue applying the same margins, once the 55MW level had been reached. Using a "naked", no contingency margin demand of 50.5MW against a 70MW target, yields a whopping 39% margin. On the other hand, the first maximum load capacity estimate made for this project back in 1998 was only 20MW (RPT-W375-TE00009, Sect. 3, reads "The U.S. DOE has committed to deliver up to 20MW electrical power at 13.8kV, 60Hz, to supply the power needs of the TWRS-P (presently,

WTP). the 20MW of power has been estimated to be sufficient for overall plant power consumption (with margin allowed), when the plant is in full operation for phase B2")

There're two limitations on max power demand, besides a 62MVA max DOE transformer FA rating:
1. The DOE transformers' LTC is already maxed out for the Normal configuration at 10% and 8.75% for each of the two main transformers, respectively (see Sect. 2.5).
2. The 13.8kV DOE Utility buses are rated at 3,000A and Bldg 87 buses and incoming four, 6 (3-1/c-750kcmil) each cable feeders in underground duct banks at 2,000A. This established the maximum power flow, 71.7MVA at DOE bus and 47.8MVA at each load group bus in Bldg 87.

2.3 Available Options

The rationale for a 0-rating (Fail) for Functionality, as applied to Options 5 and 6, is unclear to me. With A6 sub using a breaker make/tie/make, breaker-closed, bus configuration, see 2.1(a), a loss of a single offsite transmission line shouldn't be a factor. It is a loss of one of the two main transformers or utility buses that impacts the power availability.
In Option 5 using a swing bus configuration, this liability is effectively minimized by being limited to a loss of bus only. Thus, the maximum available power is 124MVA (based on available transformer capacity) and 72MVA (3,000 x 13.8 x 1.732= 72MVA) based on the 3000A bus availability, both acceptable. It may require an additional bldg though, which will drive up the costs.

Similarly, for Option 6, it is unclear why this option cannot meet the maximum power requirements. This option will have more practical sense if the extra transformer pad and cable stubs are pre-installed, as well as anchor bolts holes. Then the replacement time should be no more than 48 hours and the system will be back to a 124MVA maximum (transformer) and 72MVA (bus) maximum limit. Looks like a viable and relatively inexpensive option. One alternative to this Option 6 could be a completely pre-installed spare transformer with only the power connections remaining to be made at the time of switchover. In fact, an overall task of having to maintain this spare transformer in a storage facility or having been already installed on the pad outdoors doesn't look that much different. This will effectively represent a cross between Option 5 (swing transformer) and Option 6 (warehouse-stowed transformer). A review of Option 5 showed that a physical space for the 3-rd transformer was available; it is the 3,000A switchgear expansion that cannot be accommodated in the existing switchgear building and would require a new switchgear building.

This practice of keeping a spare transformer stowed and maintained in a storage facility for a quick replacement is rather common in nuclear industry, which demands a reliable safety record and acceptable return on investment. This practice was used for the step-up main high-voltage transformers by Philadelphia Electric Co for nuclear generating stations Limerick, Units 1, 2 and Peach Bottom, as well as others. As an example, see below an excerpt from the "*Reliability Assessment of the Vermont Yankee Nuclear Facility" by Nuclear Safety Assoc.*
Quote *"Spare Main Transformer - Large Power transformers such as ENVY's Main Transformer manufactured by ABB are not off-the-shelf or in stock items from a manufacturer. There is an industry-wide challenge regarding the ability to obtain replacement transformers in a timely manner. To acquire one could potentially take several years for delivery... The spare transformer is capable of being utilized if the currently installed transformer (ABB) fails, but only at 80% of the current rated output of the plant. A more comprehensive plan to include potential upgrades to the spare or access to a 100% load capacity spare should be included.* Unquote

2.4 DOE Transformer Rating

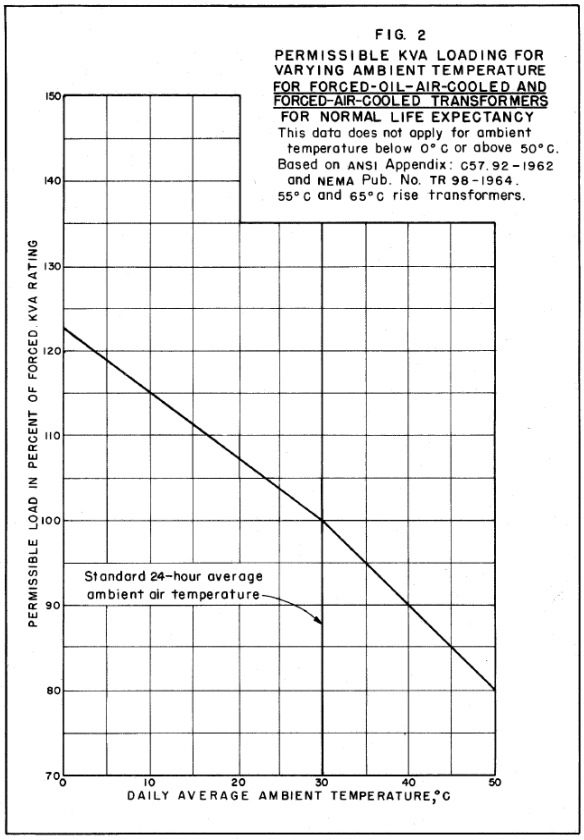
2.4.1 Basically, the nameplate rating is the rating guaranteed by the manufacturer for the 30C (86F) average temperature. Practically, the 24-hour average ambient temperature is lower, which results in

a higher available rating. As an example, decreasing average ambient temperature from 30C to 26C will add about 3% to the rating, or will make it a 65MVA maximum FA rating by adding 3MVA to the nameplate rating. See below an excerpt from ANSI C57.91 for power transformer temperature ratings.

Table 4—Loading on basis of temperatures (average ambient other than 30°C and average winding rise less than limiting values) (for quick approximation) (ambient temperature range –30°C to 50°C)

Type of cooling*	% of KVA rating	
	Decrease load for each°C higher temperature	Increase load for each°C lower temperature
Self-cooled—OA	1.5	1.0
Water-cooled—OW	1.5	1.0
Forced-air-cooled—OA/FA, OA/FA/FA	1.0	0.75
Forced-oil, -air, -water-cooled —FOA, FOW, and OA/FOA/FOA	1.0	0.75

*See 5.1 in IEEE Std C57.12.00-1995.



2.4.2 Recommend checking with the DOE main transformer manufacturer on available means of increasing the maximum available capacity. Although this is a very long shot, but recommend discussing this subject with the transformer manufacturer anyway.

Note: This is unfortunate that the transformers had been specified and procured by the DOE with a single 65°C temperature rating. It is a common practice in the industry to specify a dual 65°/55°C temperature rating for the large oil-filled transformers with a long lead time. This practice, for a marginal, about 5%, increase in price yields a 12% increase in power rating.

In recent years, there were several papers published on the subject of increasing the existing transformer rating (*"A Solution for Maintenance of Power Transformers Operating Under Frequent Overloads", by Duart,* et al). This paper cited

> Recently a breakthrough has been achieved in South America as the first unit operating under 220 kV was uprated by Ande, the local utility in Paraguay [12]. The modernization has been done by Los Conce in Argentina. The transformer was a BBC 30/35/10 MVA – 220/66/23 kV built in 1986 that was uprated to 40/30/15 MVA – 220/66/23 kV.
>
> As Table 2 shows a final price of 70% of a new transformer with the same capacity was achieved with the transformer insulated with ***hybrid*** insulation. But compared to a new 40/30/15 MVA – 220/66/23 kV the savings were about 60% and the utility has gained a 33 % overload capability with lifetime extension over 25 years.

Table 2 – Economics comparison

Transformer replacement options	Price ($)	Comparison vs conv. rep	vs ***Hybrid*** rep
Replacement by a new 30/25/10 MVA– 220/66/23 kV unit with conventional insulation	300 000	62 %	43 %
Replacement by a repaired 30/25/10 MVA – 220/66/23 kV unit with conventional insulation	185 000	1	13 %
Replacement by a repaired 30/25/10 MVA – 220/66/23 kV unit with ***hybrid*** insulation with 33 % overload capability	210 000	- 12 %	1
Replacement by a new 40/30/15 MVA– 220/66/23 kV unit with conventional insulation, providing 33 % overload capability compare to original unit	500 000	Not applicable	140 %

2.5 Auto-LTC

The DOE main transformers' automatic Load Tap Changer (LTC) is already maxed out for the Normal configuration at 10% and 8.75% for each of the two main transformers, respectively. As an experimental study, in order to evaluate the available margin for the LTC, I revised the Worst Case configuration by adding a fictitious 7MVA lumped load to buses 87001A and 87002A, 3.5MVA each, thus arbitrarily increasing the total maximum load demand to 62 MVA from the present worst case of 55MVA. This established a breakdown capacity limit, as the single transformer LTC was maxed out at 10% and the voltages are still OK based on ANSI C84. Any further load increase will cause voltage degradation beyond limits allowed by ANSI C84.

For the Normal configuration though, the voltages are still depressed because I had to run this case with a 95% grid voltage selected for the Normal mode. Note that the Normal configuration was run in the Load Flow calc with a 95% grid voltage and Worst Case - with a 100% grid voltage.

2.6 Power Factor Improvement

The URS study concluded that using power factor correction capacitors isn't worth pursuing unless there is an added benefit of reducing power factor penalties. I agree. To be sure, I did a rough ETAP modeling by a touch-and-go method by dropping a capacitor bank on the main 13.8kV buses. It'll take about a 12MVAR total capacitive reactive power to increase PF from 91% to 98%. This will reduce the max MVA from 55MVA at 91.6% PF to 51.5MVA at 98.2% PF. Based on the published data, the cost of 1kVAR at 13.8kV is appr. $25 (I have a copy of OTI technical paper on this subject), which makes the total procurement cost of a 12MVAR, 13.8kV capacitor bank about $0.3M. However, the 12MVAR reactive power will definitely form a parallel resonance with the source, thus resonating at the 5-th characteristic harmonic, which can be quickly verified as:

$$h = \sqrt{[MVA /(Z_{tr\%} \times MVAR)]} = [37 /(0.097 \times 12)]^{1/2} = 5.6 = 5 \text{ (nearest harmonic)},$$

where h is a harmonic order.

Because the 5-th harmonic shunt filters add substantial cost to the capacitor banks, this will prove a much costlier alternative, being in the range of $1.5M to $2M, plus installation costs and the cost of power breakers. Note that DOE doesn't presently envision having to pay a PF penalty to BPA, which makes this investment a no-go. Note that the latest ICD-11, rev. 4, didn't include a power factor discussion. However, ICD-11, rev. 2, did address a power factor subject in App. A, issue No 11-7, as follows:

The table below documents issues closed since the last published revision to this document. Issues closed prior to the last revision will be found in earlier revisions to this document.

Issue Number	Issue	Responsible Person(s)	Forecast Closure Date
11-7	The BPA can assess a power factor penalty for reactive power on the 230 kV line feeding substation A-6 below an equivalent of 0.97. The entire 230 kV loop, with its points of delivery at the Midway and Ashe substations, is metered to determine total reactive power, and whether there is a power factor penalty. Currently the 230 kV loop reactive power is leading (the capacity varies, but is approximately 12 MVAR, worst case). Therefore, there is some capacity before a power factor penalty would be assessed. The reactive power added by the WTP would need to be routinely evaluated for its effect on the 230 kV loop. If a power factor penalty were incurred, it would be assessed to the WTP. The reactive power will be measured on a monthly basis and evaluated for power factor penalty. A power factor penalty would essentially continue for a 1 year period. **The ICD team examined BPA power factor penalty structure and performed an evaluation of power factor correction options based on current knowledge of plant design and operation. Based on this evaluation, the best value to government is no power factor compensation beyond that which is in the current design. Issue closed by 10-16-02 ICD 11 meeting minutes (CCN 042780).**	E Eddrief (WTP)	Closed 16 Oct 2002
[illegible]	[illegible]	R Ciolli	Closed

2.7 Construction Power

The question if the 7MW, 13.8kV construction power feeder can be used for permanent operating power depends on the design and construction standards used for this feeder, i.e., if this feeder for construction power can meet stricter requirements used for operating power. Generally, it brings more trouble than merits to try and integrate a separate feeder in a power scheme (phase rotation, synchronization, voltage drop, etc.) However, this feeder could still be considered as a feeder to a separate, stand-alone facility. For example, PTF Chiller Bldg 13 has a total demand of about 4MVA.

As far as the $5.5M cost of this construction feeder... It is of interest that Bechtel/BNFL 1998 power infrastructure study, RPT-W375-TE000009, Electricity Supply, Transmission Lines and Substation, Sect. 6.1.2, Construction Power, conservatively estimated this cost at $500K, or 11 times lower than the present $5.5M estimate (see excerpt below):

Quote "*The 14.7 MW of available capacity at Substation 251W with 13.8 kV power could adequately supply the expected temporary construction power requirements of about 5 to 7 MW. In addition to the existing 13.8 kV power line, a new temporary overhead or underground line, 6-miles in length, should be constructed from the Substation 251W to the TWRS-P facility. The new line is required to assure sufficient capacity of construction power. The requirements for power quality (such as voltage regulations) for construction power are not as strict as for the permanent power supply line to the TWRS-P facility. Also, the requirements for the permit for temporary lines are less restrictive than for a permanent power line. Therefore, installation of this construction power line should be able to support the construction need date for power. The construction cost of this temporary line is conservatively estimated at $500,000*" Unquote

2.8 Electrical Losses

The ICD requires that a "5% electrical loss margin shall be included."
We need to make sure the DOE understands that the maximum power demand numbers calculated by ETAP do include electrical losses internal to WTP - <u>but do not include losses in the DOE transformers</u>. Those losses are at appr. 10% and almost exclusively reactive. For example, in the Worst Case configuration, the maximum power demand is assessed at 55MVA (50.5 + j21.7), with electrical losses already included. However incoming power demand flowing from the 230kV grid in the DOE transformer primary is 59.56MVA (50.9 + j31), thus representing a loss of 8% on MVA base. In summary, inasmuch as WTP electrical losses are included in the total maximum power demand, no separate 5% margin is required.

2.9 Electrical Loads

The LF calc incorporated the most conservative approach to electrical loads. One recommendation that could be worth pursuing is applying a conservative but yet a little more aggressive loading scheme for the evaluation purposes, starting with the Bldg 91 motor loads. For example, even a slight reduction in demand due to the baseload requirements will yield a substantial reduction considering very large motor loads (4 x 4,500HP, PSA-CMP, incl.1 sp., + 3 x 1,750, CHW-CHU, 0 sp., + 3 x 1,200HP, CHW-CHU, incl.1 sp., + 3 x 1,000HP, PSA-CMP, 0 sp., + 3 x 800HP, PCW-PMP, incl.1 sp.), total installed connected demand - 32,250HP, running load demand - 25,750HP or about 60% and 47% of WTP power demand, respectively.

REVIEW COMMENT RECORD (RCR)

1. Date	2. Review No.
06/22/2010	
3. Project No. Project Number	Page 1 of 2

5. Document Number(s)/Title(s)	6. Program/Project/Building Number	7. Reviewer	8. Organization/Group	9. Location/Phone
Analysis of Power Delivery to WTP Study Number: 17-05-110-001		Phil Zavadivker	BNI/ WTP Oakland	Oakland, CA

17. Comment Submittal Approval	10. Agreement With Indicated Comment Disposition(s)	11. CLOSED
Date / Organization Manager (optional) (print and sign)	7/8/10 Date Phil Zavadivker Reviewer/Point of Contact (print and sign) Jeremy Wilkins Author/Originator (print and sign)	7/8/10 Date Phil Zavadivker Reviewer/Point of Contact (print and sign) Jeremy Wilkins Author/Originator (print and sign)

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
1	General				Option 5 – Swing Bus (transformer), does not technically meet this requirement and was formally rejected as such. However, as you are aware, a swing bus effectively eliminates the criteria for 100% WTP operation on a single transformer; thus this should still be an option for consideration. However, there was insufficient space in the A6 substation switchgear building to add the two new vertical sections necessary to fully implement a swing transformer. This drove the need for a second switchgear building, relocating one of the existing switchgear, 3 new bus duct (to maintain the current design configuration), and implementing approximately 2/3 of the future 230kV expansion design. Because of this, it was deemed more cost effective to implement Option 4, which has the added benefit of essentially not changing the fault current.	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	which will meet the total 70 MW requirement. We suggest that you add this option in the study.					
4	Para. VI.B.1.d.(2)(b)(i) "This is not a recommended normal electric plant line-up." The switching between the different sources are at the 87002A and 87003 buses. The selection between the two different sources does not appear to have any different results. We suggest that this recommendation be reconsidered.				The statement, “This is not a recommended normal electric plant line-up.”, was deleted and this section of the study was revised accordingly. This recommendation was made based on the presumption that normal plant operations would either have all of the “A Train” loads running together or the “B Train” loads running together and that there would not be an operational intermixing of A loads with B loads, other than for maintenance or component failure.	
5	The URS Study recommends Option 7 as the preferred alternative. It is understood that URS doesn’t view this option as the ideal solution, but only as the best of all available options, with none being perfect. However, following disadvantages for Option 7 warrant a closer look at this option. • This option involves substantial changes in WTP facilities and , if implemented, may result in cost and schedule impact to WTP. • Will necessitate shared control of WTP switchgear with the 230kV utility operator, Mission Services Alliance (MSA) for the DOE • Four incoming breakers at Bldg 87 switchgear 87001A(B) and 87002A(B) will be used as the point of interface ("PCC - Point of Common Coupling" in				The study was revised to indicate that both the WTP project and the Electrical Utility were not in favor of Option 7 due to these same disadvantages that are called out in the study.	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	your report) • Ditto for the utility metering point • Bldg 87 switchgear will have to be modified for sub. A6 relaying • Contract change will be required for modifications to Bldg 87 switchgear. Changes to contract documents (ICD, PDSA, BD, etc.) will be required • Two 75kVA, 13kV feeds for a 208/120V service will have to be routed from Bldg 87 back to Sub A6 • Will result in increased short circuit contribution. Main transformer impedance will need to be re-calculated • Main transformer differential (87) protection zone for the Main DOE transformers will have to include Bldg 87 incoming breakers (400-ft wire run) • 400-ft-long 750kcmil cable leads, 4 x 6 x (3- 1/c-750), from A6 to Bldg 87 are left unprotected from overload • Will create a safety concern in not being able to isolate the Main DOE transformers from within A6 sub for a fault, fire, repair or maintenance. • Cables between Sub. A6 and Bldg 87 and the duct banks have been installed already.					
6	Option 6 (a third spare transformer stowed in the warehouse) got a “Fail” rating for Functionality because this Option supposedly wouldn’t meet the required minimum capacity limit. This option deserves a more careful consideration, perhaps being enhanced with some low-cost improvements, such as pre-installed transformer pad, pre-drilled anchor bolt holes, cable stubs, and ready-made cable connections to enable transformer				Yes, this could be done. Yet, as was pointed out in the study, this doesn’t meet the basic 70MW during operations on a single transformer. Even if this was deemed acceptable, why would DOE want to implement this option, when approximately the same amount of money could be spent that fully complies with the study requirements of 70MW on a single transformer?	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	replacement and installation under 48 hours. One alternative could be a completely pre-installed spare transformer with only the power connections remaining to be made. In fact, an overall task of having to maintain this spare transformer in a storage facility or having been already installed on the pad outdoors doesn't look that much different. This will effectively represent a cross between Option 5 (swing transformer) and Option 6 (warehouse-stowed transformer). A review of Option 5 showed that a physical space for the third transformer was available; it is the 3,000A switchgear expansion that cannot be accommodated in the existing switchgear building and would require a new building.					

From: Wilkins, Jeremy D
To: Ziegenbein, Richard S
Subject: FW: Bechtel"s Comments on the URS Study Titled, "ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW (76.4MVA)", 17-05-110-001 Rev 0
Date: Thursday, July 08, 2010 7:29:11 AM

Richard,

BNI forwarded the same comments with the CCN# 217014. I just copied and pasted the original responses (the responses I sent to you yesterday) into this email.

Jeremy Wilkins, P.E.
Electrical Engineer
Washington River Protection Solutions/URS
Email: Jeremy_D_Wilkins@rl.gov
Office: 509-376-1041
Cell: 509-551-7917

From: Chan, Charles M [mailto:cmchan@bechtel.com]
Sent: Tuesday, July 06, 2010 1:07 PM
To: Wilkins, Jeremy D; WTP PDC
Cc: Lucke, Gary; Chuang, Chet; Claghorn, Ronald; Pell, Michael; Tam, Thomas; Al-Wazani, Mazen G; Zavadivker, Phil
Subject: RE: Bechtel's Comments on the URS Study Titled, "ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW (76.4MVA)", 17-05-110-001 Rev 0

Jeremy, **CCN# 217014**
Message is resent with CCN number added.

PDC,
Please file this email under the CCN number 217014. Thanks.

Charles
Tel. 509-371-3085

From: Chan, Charles M
Sent: Tuesday, July 06, 2010 9:15 AM
To: 'Wilkins, Jeremy D'
Cc: Lucke, Gary; Chuang, Chet; Claghorn, Ronald; Pell, Michael; Tam, Thomas; 'Al-Wazani, Mazen G'; Zavadivker, Phil
Subject: RE: Bechtel's Comments on the URS Study Titled, "ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW (76.4MVA)", 17-05-110-001 Rev 0

Jeremy,

Since the URS Study is commenced outside of WTP's scope, we are not in a position to have "mandatory" comments. The following are our comments/suggestions for your consideration.

(1) The report refers to the WTP Interface Control Document (ICD) description on the power requirement and recommends a change on the description from what was "for planning purpose" to "For the purpose of design" (see para. VI.A.1.b and XIII.A). If implemented, this would mean a Contract requirement change to WTP. We suggest that this part of the recommendation be removed.

The study is not concerned with contract scope only on technical merit. The study makes this recommendation based off of IEEE 141 section 2.4.1.4 for future operational load growth. Additionally, DOE has essentially already directed the study's recommendation in CCN 194415 and CCN 200152.

(2) Para. XIII.B "The Fifth Feeder is not recommended as a means to supply 70 MW of electrical power to the WTP .....in conjunction with any other option presented in this study."
We noticed that the study does not consider an possible option of using a combination of changing the existing 37/50/62MVA transformers to 45/60/75MVA (with the existing 13.8 kV 3000A bus switchgear in A6 substation unchanged) plus the Fifth Feeder option which will meet the total 70 MW requirement. We suggest that you add this option in the study.

Yes, I concur with the comment other; however, with the approximate $5M price tag for the fifth feeder option, it was viewed as more cost effective to upgrade the A6 substation to adequately carry the entire 70MW of electrical load.

(3) Para. VI.B.1.d.(2)(b)(i) "This is not a recommended normal electric plant line-up."
The switching between the different sources are at the 87002A and 87003 buses. The selection between the two different sources does not appear to have any different results. We suggest that this recommendation be reconsidered.

The statement, "This is not a recommended normal electric plant line-up.", was deleted and this section of the study was revised accordingly. This recommendation was made based on the presumption that normal plant operations would either have all of the "A Train" loads running together or the "B Train" loads running together and that there would not be an operational intermixing of A loads with B loads, other than for maintenance or component failure.

(4) The URS Study recommends Option 7 as the preferred alternative. It is understood that URS doesn't view this option as the ideal solution, but only as the best of all available options, with none being perfect. However, following disadvantages for Option 7 warrant a closer look at this option.

- This option involves substantial changes in WTP facilities and , if implemented,

may result in cost and schedule impact to WTP.

- Will necessitate shared control of WTP switchgear with the 230kV utility operator, Mission Services Alliance (MSA) for the DOE
- Four incoming breakers at Bldg 87 switchgear 87001A(B) and 87002A(B) will be used as the point of interface ("PCC - Point of Common Coupling" in your report)
- Ditto for the utility metering point
- Bldg 87 switchgear will have to be modified for sub. A6 relaying
- Contract change will be required for modifications to Bldg 87 switchgear. Changes to contract documents (ICD, PDSA, BD, etc.) will be required
- Two 75kVA, 13kV feeds for a 208/120V service will have to be routed from Bldg 87 back to Sub A6
- Will result in increased short circuit contribution. Main transformer impedance will need to be re-calculated
- Main transformer differential (87) protection zone for the Main DOE transformers will have to include Bldg 87 incoming breakers (400-ft wire run)
- 400-ft-long 750kcmil cable leads, 4 x 6 x (3- 1/c-750), from A6 to Bldg 87 are left unprotected from overload
- Will create a safety concern in not being able to isolate the Main DOE transformers from within A6 sub for a fault, fire, repair or maintenance.
- Cables between Sub. A6 and Bldg 87 and the duct banks have been installed already.

The study was revised to indicate that both the WTP project and the Electrical Utility were not in favor of Option 7 due to these same disadvantages that are called out in the study.

(7) Option 6 (a third spare transformer stowed in the warehouse) got a “Fail” rating for Functionality because this Option supposedly wouldn’t meet the required minimum capacity limit. This option deserves a more careful consideration, perhaps being enhanced with some low-cost improvements, such as pre-installed transformer pad, pre-drilled anchor bolt holes, cable stubs, and ready-made cable connections to enable transformer replacement and installation under 48 hours. One alternative could be a completely pre-installed spare transformer with only the power connections remaining to be made. In fact, an overall task of having to maintain this spare transformer in a storage facility or having been already installed on the pad outdoors doesn’t look that much different. This will effectively represent a cross between Option 5 (swing transformer) and Option 6 (warehouse-stowed transformer). A review of Option 5 showed that a physical space for the third transformer was available; it is the 3,000A switchgear expansion that cannot be accommodated in the existing switchgear building and would require a new building.

Yes, this could be done. Yet, as was pointed out in the study, this doesn’t meet the basic 70MW during operations on a single transformer. Even if this was deemed acceptable, why would DOE want to implement this option, when approximately the same amount of money could be spent that fully complies with the study requirements of 70MW on a single transformer?

Charles
Tel. 509-371-3085

From: Chuang, Chet
Sent: Tuesday, June 29, 2010 5:05 PM
To: Wilkins, Jeremy D
Cc: Lucke, Gary; Chan, Charles M
Subject: RE: Bechtel's Comments on the URS Study Titled, "ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW (76.4MVA)", 17-05-110-001 Rev 0

Hi Jeremy,

I am out of town presently, and won't be back until 8/2/2010. Please coordinate with Charles Chan and Phil Z. directly on all technical issues related to the Study, please cc Gary and me.

Charles, Please provide a consolidated review comment (include Phil Z.) for the 70MW Load Study back to Jeremy, with a CCN, please cc Gary Lucke, Tom Tam, Phil and me.

Thanks,

Chet

From: Wilkins, Jeremy D [mailto:Jeremy_D_Wilkins@RL.gov]
Sent: Tue 06/29/2010 10:34 AM
To: Chuang, Chet
Cc: Lucke, Gary
Subject: Bechtel's Comments on the URS Study Titled, "ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW (76.4MVA)", 17-05-110-001 Rev 0

Chet,

Regarding WTP project's review of the Study, are there any comments that need to be addressed in the study prior to the study being formally issued to the client? In other words, does the WTP project have any mandatory comments?

Jeremy Wilkins, P.E.
Electrical Engineer
Washington River Protection Solutions/URS
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REVIEW COMMENT RECORD (RCR)

1. Date	2. Review No.
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3. Project No. Project Number: 29906	Page 1 of 18

5. Document Number(s)/Title(s)	6. Program/Project/Building Number	7. Reviewer	8. Organization/Group	9. Location/Phone
Analysis of Power Delivery to WTP Study Number: 17-05-110-001, Revision B		Mazen Al-Wazani	WED/ORP	2440/2308/376-4784

17. Comment Submittal Approval	10. Agreement With Indicated Comment Disposition(s)	11. CLOSED
Date / Organization Manager (optional) (print and sign)	8/18/10 Reviewer/Point of Contact (print and sign) Date; mazen 8/17/10 Author/Originator (print and sign)	8/18/10 Reviewer/Point of Contact (print and sign) Date; mazen 8/17/10 Author/Originator (print and sign)

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1	How this study going to be released in the IDMS system. Does it have to have WRPS document number?		Release the document using WRPS procedure for analysis and document.	Y	(A) Due to the requirement for a PE stamp, the document must be a URS study. The study has been assigned a WRPS report number and will be entered into the HDCS per standard procedures.	
2	Letter submitted by S. Charboneau to WRPS required a minimum of 70 MW.		Add "Minimum" word before 70MW in the title of the analysis.	Y	(A) Added the word "Minimum" through the study in reference to providing a minimum of 70MW of electrical power to the WTP.	
3	Under Background: 1st bullet, Where did you get the 2015 design completion? This comment applies for background section IV.		Provide basis for the date.	Y	(A) This date was based on my recollection from my time on the WTP. The date has been revised to 2013 which corresponds to an Overview and Assessment presentation made by BNI Project Director during the May 3, 2010 Construction Progress Review.	
4	Under Background: 2st bullet, change 62MV to 62MVA		Change 62MV to 62MVA	Y	(A) Made the required change.	
5	Under Background, 3rd bullet, second line add the following after distribution line "C8-L5, C8X747		Add "C8-L5, C8X747	Y	(A) Made the requested change.	
6	Under background, 4th bullet, According to rev E. of calc 24590-WTP-E1C-MVE-00004, page 16, item 7.2.4 Power Demand shows the power demand from the DOE		Please verify and revise accordingly.	Y	(PA) The study references section 8.1.1 of 24590-WTP-E1C-MVE-00004, as the maximum power demand from the A6 substation at	

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	substation is 50.427MW @ pf 91.9%, adding estimated design growth of 2.5MW bring the load to 53MW, adding 15% contingency and 15% design growth it will bring the total load to 70.15 MW @ pf 91.9 = 76.33MVA. This number does not match number shown in your report of 71.7MV				50.498MW @ 91.6% pf. The study is aware that the 50.427 MW @ 91.9% pf value from section 7.2.4 is based off of WTP operations on one transformer and that section 8.1.1 is based off of WTP operations on two transformers. However, 8.1.1 was chose, since it was the maximum calculated electrical demand. The 71.7MVA=50.498*1.3/.916; i.e., the raw 50.498 MW @ 91.6% pf load with the 30% operational growth margin already exceeded the current 62MVA transformer rating. The worst case demand is 50.498 MW @ 91.6% pf (section 8.1.1) versus 50.427 MW @ 91.9% pf ((section 7.2.4).	
7	Units shown in some cases are not consistent, complete and in some cases incorrect. Your report shows values as MV. Typical for transformer size of 62MVA		Review/evaluate and revise accordingly. Provide consistency throughout the document.	Y	(A) The typo was corrected.	
8	Under background, 5th bullet, last paragraph, the feasibility study to use the present 13.8kV construction Power as a fifth feeder (24590-WTP-ES-E-09-001 is not in support of the standby loads as it states in the report. It was requested by DOE/ORP to evaluate and assess the feasibility of converting the existing WTP site construction power feed to a permanent power feed to supplement the WTP power requirements and alleviate the loading on the A6 substation.		Please review and revise the report accordingly.	Y	(A) Section XIII.B The study's reference to standby loads, was in relation to the MVE-SWGR-87003A&B, which are generically referred to as the standby buses, because all of the standby loads, plus some non-standby loads, are supplied from these two switchgear. The wording in the study was revised to clarify the reference to MVE-SWGR-87003A&B and not specifically to standby loads requiring standby power.	
9	Under summary of results, second		Verify	Y	(PA) Section XIII.A	

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	paragraph state : “the resultant raw (no design growth or contingency factor) maximum demand load of 50.498MW @ pf of 91.6% is reasonable” What is the basis of not having design growth and contingency factor? The life time of the plant is 40 years. Is it reasonable for not considering any design growth or contingency during the life time of the plant?				This statement is only referencing the gross results of the calculation. With regards to the design growth and contingency factors, these are factors that are typically utilized by the design agency to ensure that the client’s requirements are met; i.e., these values are zero at the time of design complete. However, the client would typically specify that the design agency maintain a operational growth factor of X% at the time of design complete (Title III design complete) per IEEE 141 Section 2.4.1.4 “Forecasting and Planning”; which is what is recommended in the next paragraph of the study. IEEE 141 Section 2.4.1.1 “Load Survey” describes the load estimate process as the design matures. The closing sentence of the Section states:”The power system load estimate will require continual refinement until job completion”. See study Section VI. “Review and Comment”, A, 4. a) for detailed information on load growth after design completion. The section states that a load growth of ½% per year is consistent with IEEE 141 Section 2.4.1.4 “Forecasting and Planning” See study Section XIII, “Results/Conclusions” A. for a full discussion of a 30% operational	

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					growth margin and the 40 year life span of the WTP. Section VI, A, 4 documents an another view of design and load growth margins. This section validates the current 15% design margin and the above 30% load growth margin.	
10	I strongly recommend a section that captures all recommendation. Issues. Recommendation need to be clear.		Evaluate and revise as required	Y	(A) Table 1 The executive summary and conclusion are already broken down into each of the six areas of the study. The pertinent recommendations and issues are called out in these sections as is appropriate.	
11	Under Fifth Feeder Study, third paragraph, top of page 11. The term of standby loads is used. It needs to be clear that the paragraph talks about loads needed to be backed up by the standby power and not the standby loads.		Evaluate and revise accordingly	Y	(A) Section XIII.B The study wording has been revised as recommended.	
12	Recommendation, wherever you have MW, provide the MVA between parenthesis. Throughout the document sometimes you talk about MVA and sometimes about MW. This is going to be very confusing to other people reading the report.		Wherever you have MW, provide the MVA between parentheses.	Y	(A) The study has been revised as recommended.	
13	Second paragraph of page 11, the report talk about Power Factor Correction System but it does not give more detail on the size of the capacitors required. Also, Do we need the power factor correction regardless of the capacity needed so we won't be penalize for not meeting utility minimum power factor.		Please evaluate and revise accordingly	Y	(PA) Section VII. This Executive summary section of the study pertains to the fifth feeder study. Power factor correction was only mentioned in this section, because power factor correction could be implemented in conjunction with the fifth feeder. The next	

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					section in the executive summary covers power factor correction system and the recommendations made. In the body of the study, under power factor correction, the size of the required capacitors is provided based on a 70MW@91.6%pf.	
14	Page 12, Second paragraph, Why using 80% vs 91.6% which is documented in the load flow calc.for the cost/benefits analysis?		Evaluate and revise accordingly.	Y	Power factor is determined by the loads and there will be additional load growth and changes to the existing loads until the design is complete. This will result in a final load power factor that is likely different than the current calculated power factor. One possibility is that the power factor could be less than the current 91.6%. 80% power factor was chosen as a means to bound the actual value of the power factor when the loads reach 70MW. The cost benefit-analysis was also performed at 70MW and utilizing the current 91.6% power factor.	
15	Page 12, 4th paragraph, item 2 need to state clearly the requirements for performing Harmonic Analysis is crucial. The December 2010 schedule shown in PIER 09-1038 is to "Evaluate the issue identified in DOA Observation A-09-AMWTP-RPP-WED-RPT-002-O3 and provide a response". It does not show the analysis will be performed.		Evaluate and revise statement accordingly.	Y	(A) Section XIII.C The Executive Summary section was revised in its entirety and no longer refers to a harmonic analysis. Harmonic Analysis is addressed in the body of the report in Section XIII, C. The Executive Summary portion of the discussion was down sized to accommodate editorial comments from URS and Central Engineering. No details have been lost, just not repeated within the Executive Summary section.	
16	Page 12, under Viable Options to Deliver a		Evaluate and revise accordingly	Y	(A) Executive Summary item 4 and	

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	Minimum of 70MW to WTP. Does cost estimate include installation, testing, and design change of current configuration?				Section XIII.D The study was revised to clarify that ROM TIC generally includes (engineering, procurement, construction, and commissioning cost); however it does not include BNI's cost estimate for implementation of Option 7.	
17	The executive summary should include conclusions and brief description of items to be evaluated that are shown on page 3 and 4 of the scope of work provided by WRPS transmittal number WRPS-1000326 R2. The reader should have answers to those items without going to the body of the report. The body of the report should have a detail on your evaluation and how you came up to this conclusion. Options should be clearly and briefly provided in the executive summary.		Evaluate and revise accordingly	Y	(A) Where appropriate, the executive summary address each of the items as requested.	
18	Page 12, 3rd paragraph. It states the most significant technical risk associated with option 1 and 7 is a higher available fault current due to a large transformer. 1) Has this issue been analyzed?\ 2) Is it going to be analyzed when performing the SKM study on the utility side? 3) How does this option impact the cost and schedule? 4) Why would you recommend this option if it could pose significant technical risk?		Evaluate and revise accordingly	Y	1) Analyzed sufficiently to indicate that it is viable to implement. Section X.B.7 2) No, in order to answer if a transformer with the appropriate impedance value can be procured, the short circuit contribution from the WTP motor loads would have to be provided by the WTP project or it would have to be independently determined. 3) No impact to schedule. 4) The risk associated with the 100 MVA transformers is the higher available short circuit they present, but this risk is mitigated by	

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					procuring the transformers with the appropriate impedance, which is commercially available.	
19	Page 12, 4th paragraph, show more detail in the body of the report that support your statement of IEEE C57.91 specially where you stated" This guide allows for exceeding the name plate of a transformer, while maintaining specified temperature parameters, for up to several months and can occur 2 or 3 times over the normal life of the transformer."		Provide section number of the IEEE and actual verbiage.	Y	(A) Section XII.2.a The study has been revised as requested.	
20	Page 13, 4th paragraph. Have you consider the cost of maintain the transformer when it is stored. There are usually certain maintenance requirements on spare transformer that the vendor usually recommend.		Evaluate and revise as required	Y	True; however, these are operating costs and operating costs have not been included in any of the options. The Executive Summary, third paragraph, 4th item describes the ROM cost includes only engineering, procurement, construction and commissioning. Maintenance costs have not been included in the ROM cost estimates.	
21	Page 14, 1st paragraph. Re-visit the numbers provided. Provide references.		Verify	Y	(A) The numbers were revisited and were validated as they were.	
22	Page 14, 2nd paragraph, under Hanford 230kV system Capacity. State the following "The Hanford 230kV electrical utility system information was not available for review to determine additional spare capacity." This item is one of the most critical items that ORP would like to have an answer for, for making decision on the electrical system upgrade. Power analysis of the utility system need to be completed to evaluate system capacity and any other problems like system loading, voltage drop and short		SKM analysis and evaluation of Hanford 230kV electrical utility system is needed and required by ORP and WRPS scope of work.	Y	(A) The SKM files presented were not technically acceptable to perform an analysis. A preliminary review of the 230kV system capacity has been made based on available information, with the preliminary finding presented. RL has taken the lead to coordinate a BPA power flow analysis, see July 15, 2010, 7:01 AM e-mail from R. Krekel (copy attached to this RCR.)	

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	circuit study.					
23	Page 14, 3rd paragraph. The evaluation of loss of transformer fan cooling should be performed using the vendor file as well as the IEEE C57.91. The evaluation in this paragraph was made based on the IEEE only.		Review vendor file and provide additional discussion as required.	Y	(A) Section XII The study has been revised to include the transformer vendor O&M manual.	
24	Basis for cost estimate: 3rd item has ABB vendor name. Is the cost estimate, you consider buying same type and same manufacturer transformer for the existing one we currently have in the A-6 substation. If not, would that make a difference regarding maintainability and reliability of the system?		Evaluate and provide response.	Y	(R) ABB budgetary pricing was utilized for estimating the ROM price for each of the options presented. Other vendor pricing would be within the accuracy of the ROM estimate. The manufacture of the transformer will be determined through the standard government procurement process, which unless a sole source procurement is authorized, the lowest priced vendor based on an engineering specification will be utilized. The maintainability and reliability of different vendor supplied transformer is beyond the scope of this study. New transformers will require the design and installation of concrete pads and oil retention systems. The ROM costs include these concrete costs.	
25	Under Purpose, it state “There are five distinct”, the report shows 6 items.		Verify and revise accordingly.	Y	(A) The study is revised as appropriate.	
26	Under Scope, item D, Add “Maintainability”		Add maintainability	Y	(A) The study is revised to include Maintainability.	
27	Under scope, Item E, add, evaluation of the system shall include electrical analysis using SKM software for the load flow, voltage drop and short circuit study. Results will be evaluated including impacts on the currently design 230kV and		Add, evaluation of the system shall include electrical analysis using SKM software for the load flow, voltage drop and short circuit study.	Y	(A) The SKM file was not made available to perform analysis. A preliminary review of the 230kV system was made based on available information, with the preliminary finding presented.	

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	A-6 substation.					
28	The following items have not been addressed under the scope or purpose. These items listed in the scope of work for deliverables: 1- Review of data provided by BNI, WRPS and MSA, including loads and required contingencies, redundancies and operability 2- Compare needs to existing system capabilities and expansions 3- Weigh options using a cost-benefit analysis 4- Make recommendation to ORP on the preferred path forward 5- Provide rough order of magnitude cost estimate and schedule to implement the recommended options 6- Confidence in the cost estimates shall be presented either by a cost range or confidence level 7- The basis of the cost estimates shall be documented.		Please evaluate and ensure the report is been revised to address these items.	Y	(PA) Where appropriate, each of these items has been addressed / provided in the study; however, as pointed out these items are not necessarily called out explicitly, although inferred, in the scope or purpose. 1- Referenced Documentation 2- Section XI 3- Section X 4- Section XIII and executive summary 5- Section X 6- Executive Summary part 3 7- Executive Summary, Basis for Cost and Schedule Estimate; Att. 1-4	
29	Codes and Standard section does not list all code and standards listed within the body of the report. Also, evaluate if any of the following Codes and standards apply: 1- IEEE-379, Standard Application of the Single-Failure Criterion to Nuclear Power Generating Station Safety Systems 2- IEEE-603, IEEE Standard Criteria for Safety Systems for Nuclear Power Generating		Evaluate and revise accordingly.	Y	(A) The study was updated with all of the codes and standards that were utilized in the development of the study.	

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	Stations 3- C57 Series, *Distribution, Power, and Regulating Transformers*					
30	The basis of design state the following: "Offsite power is provided to the WTP from Site Services Electric Utility, hereinafter referred to as the *utility*. A utility-furnished and maintained substation is located next to the WTP site. The substation receives power from two 230-kV overhead transmission lines that originate at the Midway substation 251(A8) and the Ashe switch station (A22) respectively. The transmission lines feed power to the two utility substation transformers, which are each rated 230-13.8-kV, 37/50/62 MVA. Within the substation, the utility substation transformers supply power to a utility-furnished and maintained, single switchgear lineup with two incoming breakers and a bus tiebreaker, this isolates the two substation transformer incoming feeds. The utility-furnished switchgear has four feeder breakers; two per utility substation transformer, which provide power to the WTP power distribution system. The total plant load in the WTP is divided into two load groups, designated as plant load groups A and B. Each utility substation transformer and associated load group switchgear feeders are sized to provide power to the entire WTP plant electrical load if the other utility substation transformer or load group switchgear is unavailable. ICD 11, *Interface Control Document for Electricity*, (24590-WTP-ICD-MG-01-011) defines the physical and administrative interfaces for the electricity interface during WTP design, construction, and operations."		Please evaluate and verify impact on your report including options and cost.	Y	No impact to the study. This document will likely have to be revised, depending on the option selected by DOE for implementation.	
31	The Safety Requirements Document section4.4-4 state the following: An onsite electric power system and an offsite electric power system shall be provided to permit functioning of systems designated as Safety Class. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to ensure Safety Class functions are maintained in the event of postulated accidents. Onsite electric power systems		Please evaluate and verify impact on your report including options and cost	Y	No impact to the study. This document will likely have to be revised, depending on the option selected by DOE for implementation. Each of the configurations that have been evaluated are consistent with the existing design, thus none of the safety basis documents would have	

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	shall be provided to permit functioning of SC systems that require electrical power to perform their safety functions during loss of offsite power as determined by the accident analysis. The onsite power systems shall include sufficient independence, redundancy, and testability to ensure that the safety function can be performed under postulated accident conditions, including a single failure if postulated. Physical and electrical separation shall be provided between diverse or redundant SC electrical systems. Please evaluate and verify impact on your report including options and cost.				to be revised.	
32	Have you included any cost for fire protection system for any of the options required new or additional switchgear building?		Evaluate and revise accordingly	Y	(A) Yes, it is part of the ROM sq. ft. pricing.	
33	The following Preliminary Documented Safety Analysis to Support Construction Authorization; state the following: General Information (24590-WTP-PSAR-ESH-01-002, Rev.4l: "2.8.1.1 Offsite Power Offsite power will be provided to the WTP from the Site Services Electric Utility, hereafter referred to as the *utility*. A utility-furnished and maintained substation is located next to the WTP site. The substation receives power from two 230-kV overhead transmission lines that originate at the Midway substation 251(A8) and the Ashe switch station (A22) respectively. The transmission lines feed power to the two utility substation transformers, which are each rated 230-13.8-kV, 37/50/62 MVA. Within the substation, the utility substation transformers supply power to a utility-furnished and maintained, single switchgear lineup with two incoming breakers and a bus tie breaker. This isolates the two substation transformer incoming feeds. The utility-furnished switchgear has four feeder breakers; two per utility substation transformer, which provide power to the WTP power distribution systems. The total plant load in the WTP is divided into two load groups,		Please evaluate and verify impact on your report including options and cost	Y	No impact to the study. These documents will likely have to be revised, depending on the option selected by DOE for implementation. Option 1 implementation may require revision of the transformer sizing to 60/80/100 MVA. If the RL/MSA sponsored A6 Substation expansion option is implemented then the PSAR will need to be revised to show that the WTP loads could be fed from four transformers, two 62 MVA and two 100 MVA transformers.	

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	designated as plant load groups A and B. Each utility substation transformer and associated load group switchgear feeders are sized to provide power to the normal operating WTP plant electrical load profile if the other utility substation transformer or load group switchgear is unavailable." Balance of Facility Specific Information (24590-WTP-PSAR-ESH-0 1-002-05, Rev 4e) state the following: 2.8.2 13.8 kV Supply System The 13.8 kV power to the WTP site will be provided via the DOE site substation (Figure 2A-2). The DOE site substation will consist of two 230-13.8 kV power transformers supplied from two separate offsite 230 kV power lines. The DOE transformers will provide electrical power to the WTP main switchgear. The four main feeder cables will be routed from the 13.8 kV feeder circuit breakers in the DOE switchgear via four concrete encased underground ducts to the WTP main 13.8 kV switchgears in the switchgear building. Figure 2A-2 is a single-line diagram of the electrical supply system from the distribution grid to the building.					
34	Page 21, Assumption D, it state "This study assumes that the existing 230kV system has sufficient capacity to handle the increased load capacity of each of the presented options.". This item is one of the major and crucial items of the scope of work deliverable. It needs to be analyzed not to be assumed. SEE ITEM 27 ABOVE.		Analyze the 230kV system and provide results in the report.	Y	(A) The SKM file was not made available to perform analysis. A preliminary review of the 230kV system was made based on available information, with the preliminary finding presented.	
35	Page 22, Item b). The propose change state for the purpose of the design, what about future growth. The design margin should be cleared up front and not at each stage of design complete, construction complete, start-up, etc.		Evaluate and revise report accordingly.	Y	(A) The recommended operational growth margin is specifically for future growth. i.e., based on the existing 62.5MVA transformers and the recommend operational growth margin of 30%, the WTP maximum electrical load at Title III, would be limited to 48MVA. The 48 MVA is "back calculated" from the current	

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					transformer size of 62 MVA. This calculation only demonstrates that accommodating a 30% growth margin means the transformers are too small when compared to the BNI load calculation. Study Section XIII "Results / Recommendations" A 5th paragraph discusses design growth, contingency factor and operational growth margin as follows: "Design Growth and Contingency factors are utilized by design agencies to ensure that they meet client specified operational margins as recommended above. At the point of Title III design complete, these factors should no longer exist and the calculated electrical design load plus the operational growth margin should not exceed the clients' specified maximum average operational power available for project operations.	
36	General comment: The report should have section in the conclusion and the results that clearly identified but not limited to Recommendations, Issues and maybe a table that shows different options, with advantage, disadvantage and cost.		Evaluate and revise accordingly	Y	(A) For both the executive summary and conclusion, there are recommendations for each of the areas reviewed. Table 1 has been added.	
37	Page 21, under acceptance criteria, provide more detail why those criteria are acceptable, and do they meet industrial and code standards. For example, why would a horse brake power is acceptable for the calculation rather the use of the name plate rating of the equipment. Why the power		Evaluate and revise accordingly.	Y	(A) Section VI.A.2 The study has been revised to add additional detail.	

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	demand is is acceptable. How are we conservative in the calculation, etc.					
38	Page 23, item d. There was no evaluation done to validate items in "d", item 1 through 3. It looks like it rely on the AHJ approved proposed action.		Evaluate and provide concurrence and the basis for the concurrence and revise document accordingly.	Y	(A) Section VI.A.2 Item 1 is explained, "This factor is taking credit for the difference in the designed power needs for mechanical operation and the next available standard size larger motor to drive the mechanical load." Item 2 is explained, see section VI.A.2.b). Item 3 was revised to add additional clarification.	
39	Page 23, item 3, standby loading factor. My understanding that some of these equipment will be running at the same time for a period of approximately 2 hours before they shut down one of them. How would this condition impact the loading of the system and motor starting and motors of other system		Evaluate and provide revised statement.	Y	(A) Section VI.A.2 Addressed in comment resolution #38 Item 3).	
40	Page 24, item 3a), Again the following statement have been provided, "For the Loading Factors, Diversity Factors, and Standby Loading Factor that were approved by the AHJ (the legal authority to make this decision); these are inputs to the calculation and not assumptions. The AHJ has reviewed and approved the basis for the various factors applied to the list of loads and provided them to the project for use for this calculation" It looks like again no evaluation was done, relied on the AHJ decision		Evaluate and revise accordingly.	Y	(A) Section VI.A.2 Addressed in comment resolution #38.	
41	Page 25, 3c, The report state "the basis for the power factor chosen for the lumped loads. Attachment A-3, ETAP Input Data Lump Loads included Mechanical Package		Evaluate and revise accordingly	Y	The total system MVA is not going to change based on this item, i.e., the electrical equipment (excluding the PFCS) can still be sized based on the	

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	Power Panels, is a list of 486 assorted loads, all with a .85 pf Without having more information on these loads it is impossible to say if this is a bounding assumption. However, one must realize that the given information is in terms of KVA; in other words, the total current is not going to change for these loads, but only the ratio of real versus reactive currents. This would impact the total WTP power factor and if required, the sizing of a PFCS. " what would be your recommendation, does BNI report need to have more information to verify their assumption and what kind of impact it will have on the total loading, voltage drop and short circuit.				load flow analysis. Since no power factor correction penalty is assessed, there is no need to implement a PFCS. Thus, no real need to revise this information at this time.	
42	Page 31 and 32, etc. For any calculation provide a reference for any equation used.		Revise to add references to equations used in the calculations.	Y	(PR) All equations used are standard electrical engineering equations; the sources of which are not typically called out. If abstract equations were utilized, their sources would be called out.	
43	General Comment: Provide a separate page for Acronyms and abbreviations		Provide a separate page for Acronyms and abbreviations	Y	(A) Implemented	
44	Page 34, 2b, change then to than (Typo)			Y	(A) Corrected	
45	Page 34, Item 5 and Page 35 5 Recommendation. See comment 15 above.			Y	Verification of compliance with IEEE 519 cannot be verified without completing a harmonic analysis. Section XIII, C. recommends that a harmonic analysis be performed before implementation of a power factor correction system. The harmonic analysis may show that that a filter bank be installed, which will have a direct effect on a design of power factor correction system.	

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46	Section VIII provides a grading numbering system for Functionality, Reliability, Cost and Final recommendation. The numbering system is confusing especially when you read throughout the document.		Avoid grading system if possible.	Y	(A) Section IX.D The number grading system was eliminated.	
47	General Comment: There is a lot of repetitive throughout the document. Same discussion is carried out sometime 3 or 4 times.		Avoid too much repetitive.	Y	(R) Typical for a document that has an Executive summary, a body, and a conclusion.	
48	Page 41, Section X, Option 1, Last paragraph it states "A test calculation was performed to verify viability of procuring the 60MVA" Change 60 MVA to 60/80/100MVA to be consistent with the rest of the document and not to confuse people who read the report.		Change 60 MVA to 60/80/100MV (TYPICAL)	Y	(A) Made the change.	
49	Page 42, Acronym has been used without any definitions to that acronym or references to equation used.		Provide definition for acronym used (e.g. Is.c, f, M, %Z, rms, etc) and references to equations used.	Y	(R) Standard Electrical Equations.	
50	Page 42, it calculate the required transformer impedance. The report last paragraph of page 43 it state "this calculation assumes no contribution to fault current from WTP motor loads, which is not the case. A short circuit analysis should be performed to determine the required transformer impedance (%Z) necessary to ensure the short circuit rating of the WTP electrical equipment."		What is the purpose of this calculation? According to statement provided the calculation did not show actual contribution from the WTP loads. Which means %Z that was calculated is not accurate. How is the value of 7.5 going to be any useful for us in this report? Evaluate and revise report accordingly.	Y	(R) The purpose of this calculation was to determine if increasing the transformer sizes was viable based on the limitation of the switchgear short circuit rating. The 7.5 %Z shows that there is still likely a sufficient range of transformer impedance that could be procured, depending on the WTP motor load contribution to the total system fault current.	
51	Page 41 under disadvantages talk about 4000A switchgear and breaker. Are we replacing switchgear and the main breaker? These items are not shown in the cost estimate of attachment 4		Evaluate and revise report and/or the cost estimate as required.	Y	(A) The switchgear are being replaced. The 4,000 amp air insulated switchgear come with 4,000 amp breakers that are fan cooled. These fans can fail, which is a drawback to this design option.	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
					The price of the breaker is included in the price of the switchgear.	
52	Page 44, option 2. This option required installation of second Tie-in breaker which is not discussed under option 2 or the cost estimate. Also, it does not address the fire system in the new switchgear building.		Evaluate and revise report and cost estimate accordingly.	Y	(A) The cost of the tie breakers is accounted for in the switchgear pricing and the reduced reliability is address. The fire system cost are included in the switchgear bldg.	
53	General comment: Does any changes, additions etc. required any lightning system. How it is going to be addressed in the report including cost estimate if required.		Evaluate and verify if any lightning system required and revise accordingly. Include any additional code and standard.	Y	For the recommended options there is no change to the existing lightning protection system. For the expansion of the substation option (Option 3), it would be included in the substation design cost.	
54	Page 46, Option 3, shows two 4000 switchgear. Is that required additional switchgear building? Option 1 have the same configuration and did not required additional switchgear building. I can understand that this configuration might need additional real estate to install two additional 62MVA transformers.		Evaluate and revise document/cost estimate as required. Typical for option 4	Y	Option 3 required the addition of 2 vertical sections for the additional 2 main breakers in the A6 substation switchgear bldg. There isn't physical space for two more vertical sections in the A6 switchgear building	
55	Page 52, Option 5, Swing Bus. This option was not completely analyzed. There would be some advantage to this option, 1) we have the real estate on the north side of the A-6 substation to add one more transformer. 2) Regarding adding another building or modifying existing building you had that the previous option that were considered like option 2 and 4 3) for reliability you always have 2 out three transformers available 4) you always have 124MVA availability, etc.		Evaluate and provide cost estimate for this option	Y	In order to implement this option, a new bldg would be required. Additionally, one switchgear would have to be removed from the existing switchgear bldg and relocated in the new bldg. A new vertical section would have to be bought for each of the two A6 switchgear for the additional main breakers that are required. At least one of the existing bus duct would have to be demolished and two new bus duct bought. 2/3rds of the 230kV substation future expansion would have to be implemented. With all of the above, it would be more cost effective to fully develop the future	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
					230kV future substation. i.e., option 4. A cost estimate will be provided on option #5 and the range of the estimate accommodates the two MSA swing bus options. An additional cost estimate will be developed for the RL/MSA sponsored A6 Expansion option. This RL/MSA option will be detailed within the 230 KV Hanford System Capacity narrative.	

From: Krekel, Randall N
To: Reed, Garth R; Olsen, Gary B; Al-Wazani, Mazen G; Ziegenbein, Richard S; Baker, Scott (EU); Hache, Joseph M (Mike); Dudney, Calvin E
Cc: Krekel, Randall N
Subject: BPA power flow analysis
Date: Thursday, July 15, 2010 7:00:50 AM

FYI –

I contacted our BPA Customer Service Engineer yesterday regarding the need for updated power flow analysis information. He will investigate with the BPA Transmission Planning organization to determine if the 1999 analysis for A6 is still valid or if it is out of date, or whether BPA has any other recent analyses that would satisfy our needs. The 1999 analysis for A6 did model the system for transformer ratings up to 100 MW; however, that may not be adequate if additional site loads resulting from the WRPS Phase 2 Study are also considered. If no existing BPA analyses are valid or available then we will need to develop a reimbursable project work order for BPA to perform the analysis. If BPA has any questions I will contact the appropriate individuals and we may set up a conference call with BPA to discuss their questions. I also affirmed the need to have this information in a short time frame.

I will be staying in close contact with our BPA Customer Service Engineer on this item and will let you know as soon as I hear anything from them.

Let me know if you have any questions.

Thanks,

Randy

Randall N. Krekel
Electrical Utilities Management
Infrastructure, Services, Information Mgmt. Division
U.S. Department of Energy, Richland Operations Office
(509) 376-4264 office
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REVIEW COMMENT RECORD (RCR)

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5. Document Number(s)/Title(s)	6. Program/Project/Building Number	7. Reviewer	8. Organization/Group	9. Location/Phone
Analysis of Power Delivery to WTP Study Number: 17-05-110-001		Randall Krekel	DOE-RL	825JADWIN/480-C/700 (509)376-4264

17. Comment Submittal Approval	10. Agreement With Indicated Comment Disposition(s)	11. CLOSED
Date / Organization Manager (optional) (print and sign)	Randall Krekel — Reviewer/Point of Contact (print and sign) — 8/9/10 Date	Randall Krekel — Reviewer/Point of Contact (print and sign) — 8/9/10 Date
	Jeremy Wilkins — Author/Originator (print and sign)	Jeremy Wilkins — Author/Originator (print and sign)

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
1	Background, page 9, Change 62MV to 62 MVA in 2 places		Change 62MV to 62 MVA in 2 places		Accept	Closed
2	Background, page 9, delete temporary construction		delete temporary construction		Accept	Closed
3	Background, page 9, Change 71.7MV to 71.7 MVA		Change 71.7MV to 71.7 MVA		Accept	Closed
4	Background, page 9,Add Line C8-L5 in 2 paragraphs		Add Line C8-L5 in 2 paragraphs		Accept	Closed
5	Background, page 11, Change 62MV to 62 MVA		Change 62MV to 62 MVA		Accept	Closed
6	Background, page 14, Change 71.7MV to 71.7 MVA		Change 71.7MV to 71.7 MVA		Accept	Closed

REVIEW COMMENT RECORD (RCR)

1. Date	2. Review No.
06/20/2010	
3. Project No. Project Number: 29906	Page 1 of 2

5. Document Number(s)/Title(s)	6. Program/Project/Building Number	7. Reviewer	8. Organization/Group	9. Location/Phone
Analysis of Power Delivery to WTP Study Number: 17-05-110-001		Ernie Hamm	WRPS – Central Engineering	2750E/A203/200E (509)372-0310

17. Comment Submittal Approval	10. Agreement With Indicated Comment Disposition(s)	11. CLOSED
Date / Organization Manager (optional) (print and sign)	Ernie Hamm Reviewer/Point of Contact (print and sign) Date / Jeremy Wilkins Author/Originator (print and sign)	Ernie Hamm Reviewer/Point of Contact (print and sign) 11/27/2010 Date / Jeremy Wilkins Author/Originator (print and sign)

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
1	Executive Summary is too detailed.				Reduced the size of the Executive Summary per the following; BACKGROUND – deleted section WTP LOAD FLOW CALC – deleted two paragraphs FIFTH FEEDER STUDY – condensed to one paragraph by deleting four paragraphs POWER FACTOR CORRECTION - condensed to one paragraph by deleting 6 paragraphs VIABLE OPTIONS - condensed to three paragraphs by deleting three paragraphs LOSS OF FAN COOLING – expanded from three paragraphs to five paragraphs	
2	Add table summarizing results				Added table at end of Executive Summary	
3	Change reliability section to risk				Maintained the Reliability title but added discussions within each option on inherent risks	
4	Evaluate requirement for 30% operational growth				30% (15% + 15%) operational growth is scope directed by ORP. Did not evaluate options that did not meet load of 76 MVA	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
5	Make Fan Cooling section more generic and applicable to the 62 MVA transformer				Added additional information to include the discussion on existing 62 MVA transformers.	

APPENDIX C

REVIEW COMMENT RECORD ON POWER OPTIONS SUBMITTED BY MSA

- M. Hache MSA number of pages 12

REVIEW COMMENT RECORD (RCR)

1. Date	2. Review No.
08/02/2010	
3. Project No. Project Number 29906	Page 1 of 12

5. Document Number(s)/Title(s)	6. Program/Project/Building Number	7. Reviewer	8. Organization/Group	9. Location/Phone
Analysis of Power Delivery to WTP Study Number: 17-05-110-001		Mike Hache	MSA-EU	2101M/120/200E (509)373-1853

17. Comment Submittal Approval	10. Agreement With Indicated Comment Disposition(s)	11. CLOSED
Date / Organization Manager (optional) (print and sign)	Mike Hache J.M.Hache 8-3-10 Reviewer/Point of Contact (print and sign) 8-3-10 Date Jeremy Wilkins 8/3/10 Author/Originator (print and sign)	Mike Hache J.M.Hache 8-3-10 Reviewer/Point of Contact (print and sign) 8-3-10 Date Jeremy Wilkins 8/3/10 Author/Originator (print and sign)

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
URS 1	Alternative 1: 2 ea l00 MVA Xfmrs, 2ea 4kA Swgr, Control bldg Expansion PROs • Single 100 MVA transformer can carry the anticipated load with loss of one stage of cooling fans • Operational Interface is clean, follows established guidelines for interface control (TWRS; BPA) • Separation of ownership of hardware is clean • Follows established controls of the auxiliary equipment, such as protection schemes and communication systems and interface is well understood and controlled • Hanford SCADA system design and communications and operation will remain similar • Access to EU medium voltage equipment is limited to qualified Utility personnel • Agrees with current contract re infrastructure services • Customer relays and protection schemes do not trip open the 230kV loop. • Additional interface agreements not needed with BP A • Configuration control maintained by the				URS option 1 remains the narrowly focused recommended option for providing at least 70 MW power to WTP on a single transformer. The MSA review comments have been attached to the report.	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	site utility. • Continued use of Utility existing lock and tag program. • Does not require reconnection of WTP loads to new busses if fault duty is not an issue. • Will not require modification to the 230kV system CONs • Non-standard 4000A switchgear requires fan cooled or gas insulated • Requires the expansion of the A6 swgr bldg • Performance of ops and maint functions may not allow use of established Site Utilities programs and may require training and procedures preparation for 100 MVA transformers and 4000A bus • A fault and coordination study on the impact of potentially larger fault value, especially when paralleled for switching • Transformer pads and oil containment system will have to be modified, rebuilt • Larger investment in transformers may need to add redundant backup relays to protect investment				The Disadvantages portion of the URS option 1 discussion have been updated to include the MSA concerns on this option. The MSA review comments have been attached to the report.	
URS 5	Alternative 5: l ea 62MV A Xfrnr, 2ea 13.8kV in comer brkrs, 2ea 230kV GCB, swing bus PROs • Two of any three 62 MV A transformer can carry the anticipated load. Loss of cooling fans would allow replacement of bank via switching. • Maintains use of 3000A switchgear - no increase in bus capacity required. • Operational Interface is clean, follows				URS option 5 has been updated to include cost information. The cost is comparable to URS option 1. URS option 5 was not recommended due to increased complexity of operation, additional maintenance costs and loss of reliability due to additional	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	established guidelines for interface control (TWRS; BPA) • Separation of ownership of hardware is clean • Follows established controls of the auxiliary equipment, such as 13.SkV feeder protection schemes and communication systems and interface is well understood and controlled. • Hanford SCADA system design and communications and operation will remain similar • Access to EU medium voltage equipment is limit to qualified Utility personnel • Agrees with current contract re infrastructure services • Customer relays and protection schemes do not trip open the 230kV loop. • Configuration control maintained by the site utility. • Continued use of Utility existing lock and tag program. • Does not require reconnection of WTP loads to new busses CONs • May require control bldg expansion for two new in corner breakers. • Will require protection scheme modifications to the 230kV and 13.SkV busses. • Different configuration than other EU substations may present different concerns when operating, whether performing routine maintenance or recovering from a disturbance. • Performance of ops and maint functions may not allow use of established Site Utilities switching conventions and may				components compared to URS option 1. The MSA review comments have been attached to the report. The Disadvantages portion of URS option 5 discussion have been updated to include the MSA concerns on this option. The MSA review comments have been attached to the report.	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	require procedures preparation for the different possible configurations. • Coordination and protection analysis on the different possible configurations • SCADA system points will have to be expanded. • Additional discussion needed with BPA • The relay communication for transfer trip scheme will be more complex, will need BPA buy-in • Availability of RFL equipment					
URS 7	NOT A VIABLE OTPION TO EU Alternative 7: 2ea 100 MVA xfrnrs, Direct Feed to Bldg 87 PROs • Higher reliability (minimal) due to less equipment that could fail • Eliminated cost of new switchgear • Single 100 MVA transformer can carry the anticipated load with loss of one stage of cooling CONs • Operational Interface is complicated, does not follow established guidelines for interface control (WTP; BPA) • Separation of ownership of hardware is not clean • Shared control of the WTP switchgear • SCADA interface and controls will be difficult, BPA needs to have SCADA controls • Established controls of the auxiliary equipment, such as protection schemes and communication systems and interface will not be well understood or controlled. • Required contract change between DOE-RL (MSA) and WTP				The Disadvantages portion of URS option 7 discussion have been updated to include a statement by MSA that this option is not viable. The MSA review comments have been attached to the report.	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	• A6 station service will have to come from a tertiary winding from the new l00 MVA transformers or be fed from Bldg 87 • Safety practices will not be common to both EU and WTP even though operating and maintain same equipment. • Duplication of services will be required i.e. maint, ops personnel and qualification of said persons • Application and use of Utility existing lock and tag program and clearance process will be at odds with the facility programs. • Loss of configuration control by the site utility. • Additional interface agreements may be needed with BP A • Ground grids are not shared between substation and Bldg 87. • May require fiber optic communications for relays, SCADA • There still may be a need for CT positions inside the A6 Substation control bldg • For 100 MVA, may need additional differential as a backup. When going the 100 MVA size transformer, additional relaying would be wise to protect investment. • Fault on customer equipment or operation of customer BFR (if equipped) will open the loop. • Mis-coordination of customer equipment could also open the loop. • With no EU bus tie, will need to add reverse power relays • May need communications between A6 and 87 Bldg for high speed tripping • Uncertain how the A6 control bldg will					

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	be bypassed • Metering will be required in Bldg 87 • Bus Tie Control in Bldg 87 • A fault and coordination study on the impact of potentially larger fault value, especially when paralleled for switching at Bldg 87. • Transformer pads and oil containment system will have to be modified, rebuilt • Larger investment in transformers - may need to add redundant backup relays to protect investment					
MSA 1	Alternative EU 1: 1 ea 62 MV A xfmrs, 2ea outdoor l3.8kV brkrs, l ea 230kV GCB, Swing Bus PROs • Two of any three 62 MV A transformer can carry the anticipated load. Loss of cooling fans would allow replacement of bank via switching. • Maintains use of 3000A switchgear - no increase in bus capacity required • Operational Interface is clean, follows established guidelines for interface control (TWRS; BP A) • Separation of ownership of hardware is clean • Follows established controls of the auxiliary equipment, such as 13.8kV feeder protection schemes and communication systems and interface is well understood and controlled. • Hanford SCADA system design and communications and operation will remain similar • Access to EU medium voltage equipment is limit to qualified Utility personnel • Agrees with current contract re				MSA option 1 is nearly electrically equivalent to URS option 5. The physical variation is the outdoor location of the 13.8 KV breakers and one less 230 KV breaker. The reduction of a 230 KV breaker is a definite cost saving over URS option 5, but this reduction is well within the ROM cost estimate of -30% and +50%. The MSA review comments have been attached to the report.	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	infrastructure services • Customer relays and protection schemes do not trip open the 230kV loop • Configuration control maintained by the site utility • Continued use of Utility existing lock and tag program • Does not require reconnection of WTP loads to new busses • Expansion of substation control bldg not required CONs • Will require protection scheme modifications to the 230kV and 13.8kV busses • SCADA system points will have to be expanded. • Additional discussion re having two bus ties is needed with BPA • Coordination and protection analysis on the different possible configurations • The relay communication for transfer trip scheme will need to be reviewed for impact, will need BP A Review Unknowns • Cost • BPA's position on two bus ties • Coordinating the transfer trip schemes • Space for additional 230kV and 13.8kV relaying • Relay types may need to be changed				A July 26, 2010 field trip by URS and MSA to the A6 substation confirmed that the switchgear building is not large enough to accommodate the addition of the in comer sections to the switchgear. The cost of another switchgear building raises the cost of MSA option 1 to the URS option 5 cost level. The MSA review comments have been attached to the report.	
MSA 1A	Alternative EU la: l ea 62 MVA xfmrs, 2 ea indoor 13.8kV brkrs, l ea 230kV GCB, expand control bldg, Swing Bus PROs • Two of any three 62 MV A transformer				MSA option 1A is nearly electrically	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	can carry the anticipated load. Loss of cooling fans would allow replacement of bank via switching. • Maintains use of 3000A switchgear - no increase in bus capacity required • Operational Interface is clean, follows established guidelines for interface control (TWRS; BPA) • Separation of ownership of hardware is clean • Follows established controls of the auxiliary equipment, such as l3.8kV feeder protection schemes and communication systems and interface is well understood and controlled. • Hanford SCADA system design and communications and operation will remain similar • Access to EU medium voltage equipment is limit to qualified Utility personnel • Agrees with current contract re infrastructure services • Customer relays and protection schemes do not trip open the 230kV loop. • Configuration control maintained by the site utility. • Continued use of Utility existing lock and tag program • Does not require reconnection of WTP loads to new busses CONs • Requires control bldg expansion for additional 230kV relay and control panels, and the two new in comer breakers to the swgr indoors • Will require protection scheme modifications to the 230kV and 13.8kV busses				equivalent to URS option 5. The reduction of one 230 KV breaker is a definite cost saving over URS option 5, but this reduction is well within the ROM cost estimate of -30% and +50%. The MSA review comments have been attached to the report.	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	• SCADA system points will have to be expanded. • Additional discussion re having two bus ties is needed with BPA • Coordination and protection analysis on the different possible configurations • The relay communication for transfer trip scheme will need to be reviewed for impact, will need BPA review Unknowns • Cost • BPA's position on two bus ties • Coordinating the transfer trip schemes • Relay types may need to be replaced					
MSA 2	Alternative EU 2: l ea 62 MVA xfmrs, 2 ea outdoor 13.8kV brkrs, l ea 230kV GCB, Swing Bus and duplicate substation using 100 MVA transformers PROs • Provides additional required capacity for WTP • Maintains use of 3000A switchgear - no increase in bus capacity Operational Interface is clean, follows established guidelines for interface control (TWRS; BP A) • Provides power for future tank waste operations loads • Will not require capacity upgrade to A6 Substation for future 2E tank farm loads • Separation of ownership of hardware is clean • Follows established controls of the auxiliary equipment, such as 13.8kV feeder protection schemes and communication systems and interface is well understood and controlled				MSA option 2 is combination of URS option 5 and the230 KV Hanford A6 expansion option. No action was taken on this option since the 230 KV Hanford A6 expansion option will provide all required power to WTP and projected TF loads, without impacts to WTP commissioning. The MSA review comments have been attached to the report.	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	• Hanford SCADA system design and communications and operation will remain similar for existing station and will be incorporated into new SCADA for new substation • Access to EU medium voltage equipment is limited to qualified Utility personnel • Agrees with current contract re infrastructure services • Customer relays and protection schemes do not trip open the 230kV loop. • Configuration control maintained by the site utility. • Continued use of Utility existing lock and tag program. • Does not require changes in connection to WTP loads CONs • Cost • Protection issue with two substation so close together • SCADA system will have to be expanded to add new substation. • SCADA system points will have to be expanded for existing expansion. • Additional discussion needed with BP A • The relay communication for transfer trip scheme will need BP A buy-in • RFL equipment may not be available • Non-standard 4000A switchgear Unknowns • Cost • Loads needed for tank farm operations • Impact of two stations so close together • Coordinating the transfer trip schemes • Space for duplicate substation • Availability of RFL equipment					

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
RL	A6 Expansion - duplicate substation using 100 MVA Transformers PROs • Except for modification to 230kV bus and bus and transformer differential circuits and redirecting some tip circuits, does not require modification to A6 substation controls, 13.8kV systems, or the control bldg. • Provides required capacity for WTP (without contingency and load growth) with capability to pick up new WTP processes up to a total of70MW WTP load. Remaining 90+ MW from substation expansion to be used for waste feed, tank farm operations (and general area feeders if capacity still available). • New substation expansion will have enough capacity to accommodate waste feed and tank farm loads • Maintains use of3000A switchgear inside existing A6 substation - no increase in bus capacity • Operational Interface is clean, follows established guidelines for interface control (TWRS; BPA) • Separation of ownership of hardware is clean • Follows established controls of the auxiliary equipment, such as 13.8kV feeder protection schemes and communication systems and interface is well understood and controlled. • Hanford SCADA system design and communications and operation will remain similar • Access to EU medium voltage equipment is limit to qualified Utility personnel				The 230 KV Hanford A6 expansion option is recommended when considering the combination of the WTP and projected TF loads. This option has been included within the report, but as an answer to the 230 KV system capacity analysis. This option has also been added to Hanford 230 KV System Capacity discussion and into Table 1 in the Executive Summary of the report. The MSA review comments have been attached to the report.	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	• Agrees with current contract re infrastructure services • Customer relays and protection schemes do not trip open the 230kV loop • Configuration control maintained by the site utility • Continued use of Utility existing lock and tag program • No cost for Phase 1 CONs • Will require new connections or changes in connection to WTP loads • Additional discussion needed with BPA for any impacts to regional loads and BPA operations Unknowns • Cost • Transformer size needed • Loads needed for tank farm operations • Space for duplicate substation					

APPENDIX D

REVIEW COMMENT RECORD ON MSA POWER OPTION SELECTION CRITERIA

- S. Baker MSA number of pages 4

REVIEW COMMENT RECORD (RCR)

1. Date	2. Review No.
08/02/2010	
3. Project No. Project Number 29906	Page 1 of 4

5. Document Number(s)/Title(s)	6. Program/Project/Building Number	7. Reviewer	8. Organization/Group	9. Location/Phone
Analysis of Power Delivery to WTP Study Number: 17-05-110-001		Scott Baker	MSA-EU	2101M/116/200E (509)373-2028

17. Comment Submittal Approval	10. Agreement With Indicated Comment Disposition(s)	11. CLOSED
Date / Organization Manager (optional) (print and sign)	Scott Baker SM Baker Reviewer/Point of Contact (print and sign) 8/3/10 Date Jeremy Wilkins Author/Originator (print and sign)	Scott Baker SM Baker Reviewer/Point of Contact (print and sign) 8/3/10 Date Jeremy Wilkins Author/Originator (print and sign)

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
1	Minimize Changes to existing infrastructure - When considering options attempt to minimize changes to existing infrastructure (e.g., transformer, concrete pads, oil containment, switchgear/bldg mods, etc.				Consideration of minimizing impact to existing structures and components was weighed against system operation, reliability, maintenance and EPCC costs. An example of weighing system operability and reliability against changes to existing infrastructure is URS option 1 versus URS option5. URS option 1 requires replacement of 62 MVA transformers, 3,000 A bus duct and 3,000 A switchgear with larger equipment. New oil containment structures will require replacement. URS option 1 provides the high reliability and standard operation procedures. URS option 5 leaves much of the existing A6 substation equipment in place, but the additional transformer, bus ducts and switchgear section lowers system reliability due to additional equipment. The process of swinging a transformer into placer is a standard industry practice, but not a Hanford utility standard practice.	RPP-RPT-46992, REV 0 page 1 of 4
2	Additional Investment Protection - Increase size of transformers, GCB, etc				The report recognizes the MSA concern of additional investment	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	will usually result in additional equipment protection items (e.g., backup relays, additional SCADA alarm monitoring points, etc.)				protection. No changes have been made to the EPCC cost estimate due to the estimate ROM range of -30% to +50% will cover the additional protection equipment items.	
3	Oil Containment - As previously mentioned, increasing size of transformer will require new concrete footprint and additional excavation to increase capacity of oil containment system.				The URS options requiring replacement of 62 MVA transformers with 100 MVA transformers do have loaded cost considerations of the oil containment structures.	
4	WECC/NERC Reliability Standards – Protection – Tremendous impact while making option determination. WECC considers DC Batteries, Protective relays, PT/CTs, DC Circuits and Communication Circuit as Protection Equipment. These items have multiple compliance requirements associated with them. Options should minimize the quantity of new items being installed.				The ORP statement of work includes named ANSI, IEEE, NEMA and NFPA codes and standards for consideration in the study. The WECC/NERC Reliability Protection Standards are outside the scope of work for this conceptual study. URS option 1 and the Hanford 230 KV A6 Substation option appear to be viable from a WECC/NERC standards viewpoint. It is assumed that the option ultimately chosen by ORP, RL and MSA, WECC/NERC standards compliance will be a key technical issue.	
5	WECC/NERC Reliability Standards – Connections - Tremendous impact while making option determination. WECC also has many requirements associated with the connection/modifications to the existing transmission system. Few Examples • CIP-002-2: Risk-Based Assessment Methodologies, Critical Asset Listings • FAC-001-0: Facility Connection Requirements • FAC-002-0: Planning Authority Interface • FAC-008-1: Rating				The ORP statement of work includes named ANSI, IEEE, NEMA and NFPA codes and standards for consideration in the study. The WECC/NERC Reliability Connections Standards are outside the scope of work for this conceptual study. URS option 1 and the Hanford 230 KV A6 Substation option appear to be viable from a WECC/NERC standards viewpoint. It is assumed that the option	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	• FAC-009: Rating • Etc. These items have multiple compliance requirements associated with them. Options should minimize the quantity of these items being installed.				ultimately chosen by ORP, RL and MSA, WECC/NERC standards compliance will be a key technical issue.	
6	WECC/NERC Reliability Standards – BPA Certification - Large impact while making option determination. Annually BPA transmits an certification letter for the various WECC Reliability Standards in which BPAs support for compliance evidence is provided. Any significant changes to configuration may impact some of these 20-22 Reliability Standards.				The ORP statement of work includes named ANSI, IEEE, NEMA and NFPA codes and standards for consideration in the study. The WECC/NERC Reliability Standards BPA Certification are outside the scope of work for this conceptual study. URS option 1 and the Hanford 230 KV A6 Substation option appear to be viable from a WECC/NERC standards viewpoint. It is assumed that the option ultimately chosen by ORP, RL and MSA, WECC/NERC standards compliance will be a key technical issue.	
7	Training- Staying with traditional equipment will minimize costs associated with training, procedure prep, etc,				It is recognized that MSA-EU has programs in place that cover existing equipment, but the equipment ratings of the existing equipment must meet the study statement of work tasking. URS option 5 maximizes the use of existing equipment, but requires additional components which reduces the reliability of the option. Therefore the selection of larger equipment not familiar to MSA-EU was given a higher recommendation.	
8	Yard Accessibility - This needs to be considered when selecting sitting for 2nd Substation				The study is conceptual in nature and the options discussed within the study appear to be able to be accommodated in the real estate	

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
					within and near the A6 Substation. Detailed examinations of sitting for the selected option equipment and infrastructure must be performed by the design agency contracted to perform a detailed engineering analysis.	

APPENDIX E

REVIEW COMMENT RECORDS ON REVISION D OF URS STUDY

- M. Hache MSA number of pages 1
- J. Uecker MSA number of pages 1

- M. Al-Wazani ORP number of pages 11

REVIEW COMMENT RECORD (RCR)

1. Date	2. Review No.
08/25/2010	
3. Project No. Project Number 29906	Page 1 of 1

5. Document Number(s)/Title(s)	6. Program/Project/Building Number	7. Reviewer	8. Organization/Group	9. Location/Phone
Analysis of Power Delivery to WTP Study Number: 17-05-110-001, Revision D		Mike Hache	MSA-EU	2101M/120/200E (509)373-1853

17. Comment Submittal Approval	10. Agreement With Indicated Comment Disposition(s)	11. CLOSED
Date / Organization Manager (optional) (print and sign)	Mike Hache Reviewer/Point of Contact (print and sign) Date / Jeremy Wilkins Author/Originator (print and sign)	Mike Hache 8-26-10 Reviewer/Point of Contact (print and sign) 8/26/10 Date Jeremy Wilkins Author/Originator (print and sign)

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
1	Page 9, Fifth Feeder Study This section does not make sense to me. The 55MW is what was promised to WTP as free power to BNFL. It was decided to purchase 62MVA transformers. Plant power factor was an unknown quantity. The station capacity is 62MVA from a single transformer. The ICD only promised 55MW. 62MVA + 7.6MVA = 69.6MVA and not 67.7MVA, but still falls short of the desired 76.4MVA.				The 60 MVA is from 55MW at 91.6% pf.	
2	Page 58, 7. Disadvantages, 2und paragraph Is this misplaced? Should this be for option 7?				Deleted from Option 1. This discussion already existed in Option 7.	
3	Page 58, 7. Disadvantages, 3rd paragraph Is this misplaced? Should this be for option 7?				Deleted from Option 1. This discussion already existed in Option 7.	
4	Page 58, 7. Disadvantages, 4th paragraph Correct spelling mistake of operations.				Corrected.	
5	Page 76, sentence before I. Option 8 Replace and with was or is.				Made the change.	

RPP-RPT-46992, REV 0, PAGE 1 OF 1

REVIEW COMMENT RECORD (RCR)

1. Date	2. Review No.
08/26/2010	
3. Project No.	Page 1 of 1

5. Document Number(s)/Title(s)	6. Program/Project/Building Number	7. Reviewer	8. Organization/Group	9. Location/Phone
RPP-RPT-46992, revision D	29906	J. E. Uecker	MSA/EU	2101-M/373-1930

17. Comment Submittal Approval	10. Agreement With Indicated Comment Disposition(s)	11. CLOSED
8/24/2010 Date; S. M. Baker Organization Manager (optional) (print and sign)	J. E. Uecker Reviewer/Point of Contact (print and sign); Date; J. D. Wilkins Author/Originator (print and sign)	J. E. Uecker Reviewer/Point of Contact (print and sign); 8/26/10 Date; J. D. Wilkins Author/Originator (print and sign)

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
1.	Section VI.A.2.b. page 27. From a utility standpoint, the A-6 Substation appears to be properly sized.	Industrial Power Systems Handbook, Donald Beeman, copy attached.	Expound on 91% diversity factor. For example, continuous operations such as textile mills are at 90%, while semi-continuous processes such as paper mills and refineries are at 60%.		WRPS was directed by ORP to 70 MW demand. Refer to July 20, 2010 Meeting Minutes, topic #5.	No action
2.	Section X. page 48. Hanford 230kV load is 31.248 MW, not 22 MW.	BPA Power and Transmission bills, chart attached.	Change to 31 MW and correct following sentence to 185 MVA or 69%. Also change on page 10.		Will continue to use loading from June 14, 2010 Meeting Minutes, topic # 2. The proposed revised load number will not change the conclusion that the Hanford 230 KV system has sufficient capacity to carry projected WTP and Area 200 loads.	No action
3.	Section XIII.A. page 79. Transformer rating is not a limitation.	ANSI C57 Guide for Loading Transformers up to 100MVA, copy attached.	Change reword to say, "WTP is limited to a rating of 62 MVA."		Will incorporate the suggested wording.	Included comment
4.	Section XIII.E. page 84. Option 6 (Warehouse Spare Transformer) is discussed at length, but is not mentioned in the Executive Summary.	Executive Summary should reflect the Recommendations.	Include Option 6 in Executive Summary.		The Executive Summary discusses options that meet the strict 70 MW under worst case loading.	No action

REVIEW COMMENT RECORD (RCR)

1. Date	2. Review No.
08/26/2010	
3. Project No.	Page 1 of 11

5. Document Number(s)/Title(s)	6. Program/Project/Building Number	7. Reviewer	8. Organization/Group	9. Location/Phone
URS Study Number: 17-05-110-001 WRPS Report #: RPP-RPT-46992 Rev D	Project Number: 29906	Mazen Al-Wazani	ORP/WED	2440 STVCN/2308/R CHN

17. Comment Submittal Approval	10. Agreement With Indicated Comment Disposition(s)	11. CLOSED
Date / Organization Manager (optional) (print and sign)	mazen G Al-Wazani M. G. Al-Wazani 8/26/2010 Reviewer/Point of Contact (print and sign) 8/26/10 Date J. D. Wilkins Author/Originator (print and sign)	mazen G Al-Wazani M. G. Al-Wazani 8/26/2010 Reviewer/Point of Contact (print and sign) 8/26/10 Date J. D. Wilkins Author/Originator (print and sign)

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
1	In the executive summary, should include the following items: - Analyze and evaluate the existing 13.8 KV and 230 KV systems for power delivery • Verification of adequate electrical capacity or identification of impacts to the Hanford 230 KV system • Weigh options using a cost-benefit analysis • Make recommendation to ORP on the preferred path forward • The basis of the cost estimates shall be documented. • Is the incoming line to A-6 substation adequate to carry any changes or any of the	WRPS-1000326_R2 Scope of Work	Revise executive summary to include missing items		The indicated items will also be discussed in the WRPS cover report, RPP-RPT-46992, Revision 0. The format of the WRPS cover report will follow more closely the format of the tasking letters between ORP and WRPS. No revisions will be made to the Executive Summary of URS study # 17-05-110-001, Rev D. R S Ziegenbein	Addressed in WRPS report

A-6400-090.1 (REV 1)

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	options?					
2	Page 9 of 88, first paragraph, state "The maximum average operational power for the WTP is limited to 95.6MVA ….." ???		State the basis?		The basis for the 95.6 MVA is shown on pages 10, 56 and 64. Since this is the Executive Summary the basis is not required here since it is covered elsewhere in the body of the study.	No action
3	Page 10 of 88, state "no modifications to the 230kV system would be required in order to deliver 70MW". Any recommendation needs to be made here for the BPA to confirm that by performing load flow analysis to the 230KVA Hanford system?		Elaborate in the discussion to include any recommendation needs to be made here for the BPA to confirm that by performing load flow analysis to the 230KVA Hanford system		The same sentence also states "pending further evaluation and concurrence by BPA." How BPA chooses to evaluate the additional load is up to them. URS cannot speak for BPA. The wording as shown is sufficient to document that BPA has further actions to perform.	No action
4	Page 10 of 88 state "Since this option addresses both the criteria outlined in the commission of this study for the WTP electrical load demands as well as the projected electrical load demands of the Hanford site 200 Area, this option is the overall recommended option of this study to provide electrical power to the WTP and the projected		Evaluate and revise accordingly		The ROM costs are limited to the A6 Substation. Transitioning of the loads from one switchgear to another switchgear is an operational cost and was not considered. The cost of breaking into the existing 13.8 KV duct bank to the WTP and pulling new feeders cables was included in the EPCC cost.	No action

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	Tank Farm Loads." Was any consideration given to the cost and the time needed for this option. during the transition of the WTP loads to the new station Tank farm loads have not been analyzed neither any calculation have been completed up to this day for the new projected load. Please re-evaluate and verify if this option is feasible. This mean the A-6 substation will be expanded and maintained for a long time before it can be utilized.				The estimate of additional Area 200 loads is based on current load projections by WRPS. The estimate does show that the current A8 and A6 substations cannot carry the total projected load of 180 MVA. Maintenance costs are not included with the ROM estimates.	
5	Page 10 of 88, the scope of work is Identify viable options for increasing power delivery up to at least 70 MW of capability to the WTP. The letter and the scope of work did not request option to deliver power to the Tank Farm. Option 10 as it is shown on Figure#2 and as it is been described in the analysis does not meet the 70MW criteria for the WTP. The scope. The executive summary should address recommended options to deliver to the WTP minimum 70MW. Other options like delivering power to the Tank farm should be addressed in different section of the analysis.	WRPS-1000326_R2 Scope of Work	Revise the documents to address the WTP need and to comply with the scope of work.		The needs of the WTP and the scope of work is covered within the URS study. The format of the WRPS cover report will follow more closely the format of the tasking letters between ORP and WRPS. No revisions will be made to the Executive Summary of URS study # 17-05-110-001, Rev D. R S Ziegenbein	Addressed in WRPS report

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	For example, under comments by the Hanford community. and can be described and talked about in a separate section as preferred alternative solution.					
6	Page 11 of 88, 3rd bullet, it state option #1 has the shortest time for implementation of 2 years. I look at Table 1 on page 13 most of the options are 2 year period. What is the difference?				All options share a 2 year ROM schedule time period. Option 1 is therefore also the shortest implementation time period.	No action
7	What is the basis for the cost estimates provided for the different options? Also, provide summary of what is the cost estimate provided include?	WRPS-1000326_R2 Scope of Work.	Provide basis for the cost estimates.		The basis for the cost estimates are Attachments 3 and 4 appended to the PDF version of Revision D of the study. These attachments are discussed in Section XI with each of the costed options. The table is included in the Executive Summary for overview purposes only.	No action
8	Table 1, Expand description for option 10. Provide description of new components.		Revise documents to add new components		Option 10 description will be expanded to include duct bank and new feeder cable details.	Comment will be picked up
9	Table 1, option 10, Configuration as it shown on page 52 of 88 does not meet the 70MW criteria set forth in the scope of work.		Evaluate and revise accordingly		Option 10 has the advantage of making revisions to the A6 Substation when the WTP load nears the 62 MVA capacity of the existing transformers. Option 10 does meet the 70 MW criteria if the option is implemented immediately as	No action

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
					with the options considered within the study.	
10	Page 16 of 88. The purpose is missing several items that should have been addressed and identified in this section as required by scope of work.	WRPS-1000326_R2 Scope of Work	Revise the purpose section I to align with the scope of work. See item 1 above.		The indicated items will also be discussed in the WRPS cover report, RPP-RPT-46992, Revision 0. The format of the WRPS cover report will follow more closely the format of the tasking letters between ORP and WRPS. No revisions will be made to the Purpose section of URS study # 17-05-110-001, Rev D. R S Ziegenbein	Addressed in WRPS report
11	The purpose of the analysis is to: 1- Identify viable options for increasing power delivery up to at least 70 MW of capability to the WTP and make recommendation to ORP on the preferred path forward 2- Analyze and evaluate the existing 13.8 KV and 230 KV systems for power delivery. 3- Verification of adequate electrical capacity or identification of impacts to the Hanford 230 KV system 4- Compare needs to existing		Revise the purpose section to align with statement of work		The indicated items will also be discussed in the WRPS cover report, RPP-RPT-46992, Revision 0. The format of the WRPS cover report will follow more closely the format of the tasking letters between ORP and WRPS. No revisions will be made to the Purpose section of URS study # 17-05-110-001, Rev D. R S Ziegenbein	Addressed in WRPS report

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	system capabilities and expansions 5- Provide rough order of magnitude cost estimate and schedule to implement the recommended options and provide basis of the cost estimate. 6- Review certain section of the load flow analysis. The items listed under purpose are part of the main items listed above.					
12	Page 17 of 88, Add : Provide rough order of magnitude cost estimate and schedule to implement the recommended options and basis for the cost estimate.		Revise and add as stated		ROM cost and schedule development are called out on page 17, subsection C and page 18, subsection E.	No action
13	Page 20 of 88, last paragraph, why the 2.5MW was not included. The 2.5MW are loads identified in the load flow calc for loads that have not been designed yet?	Load flow analysis	Verify and revise accordingly.		2.5 MW is not mentioned because the "The maximum power demand from the DOE substation for operation of RPP-WTP plant is determined to be 50.498MW @ pf of 91.6%, <u>excluding design growth and contingencies</u>."(8.1.1) is a direct quote from the BNI load flow calculation. 8.1.2 of the BNI load flow shows the	No action

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
					"Total Maximum Power demand including Design Growth" as 52.998.	
14	Page 19 listing NFPA 70-1999 National Electric Code., Can 1999 edition of NFPA 70 be used for this modification, or NESC need to be listed?		Verify and revise accordingly.		The 1999 version of the NEC is shown to insure alignment with the BNI contract. New design and construction work would need to comply with the most recent versions of the NEC and NESC. The NESC will be included as a cited standard.	Picked up comment
15	Page 23 of 88, item 4.state "This study assumes that there are no significant harmonic interaction with the capacitor bank automatics PFCS" What is the basis for this assumption and what impact it is going to have on the system if it is significant?		Evaluate and revise accordingly		The assumption is made to facilitate the calculation of the PFCS sizing in Section VII of the study. The recommendations that a harmonic analysis must be performed are contained in the study pages 23, 38, 40 and 81.	No action
16	Page 27 of 88, item C. The report state what is the BNI AHJ provided for the loading factor, Diversity factor. It did not state if they have been evaluated by the analyst t and was the outcome of his evaluation.		Evaluate and provide evaluator results in this section.		The following statement was added, "This is an industry standard practice for calculating electrical load; as such, this study concurs with this method."	Picked up comment
17	Page 28 of 88, state the following for the standby loads "The AHJ approved a 0% standby loading factor. This is effectively a 0% duty cycle for the spare/redundant		Please verify and revise accordingly.		The statement is still bounding as long as the normal operation of the standby loads is as defined in the Power System Load Flow Analysis,	Picked up comment

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
	loads. This factor is reasonable based on industry standard operations for standby/spare equipment. Operations does not typically operate standby/spare equipment in parallel with the in service equipment, other than to momentarily (few minutes) switch in service equipment to balance run time between in service and standby/spare equipment. Ultimately, the diversity factor utilized in the Load Flow Analysis accounts for this momentary paralleling of mechanical loads." My understanding from operation in the previous meetings with BNI that some of the standby loads will be running with the other main load for 1 to 2 hours. If this is the case, would your statement and evaluation be still bounding?				24590-WTP-E1C-MVE-00004 Rev. E. In other words, if as an abnormal event a standby load is operated in parallel with the normally running load for more than a few minutes it would not change the answer.	
18	Page 48 of 88, Is the 78MVA the Tank Farm existing and projected load?		Verify and revise accordingly to add more clarification in this paragraph. Please state how much of it existing load and how much of it future loads		As stated on page 48 the 78 MVA is the Baseline Projected loads. The basis for the loads are documented in Attachment #11 appended to the PDF version of Revision D of the study. All the Attachments will be appended to the PDF version of revision 0 of the study.	No action

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
19	Page 48 of 88, last paragraph, what is the basis for the 95MVA?		Provide a basis for the 95MVA		The basis of the 95 MVA is 33 MVA from A8 and 62 MVA from A6 substation transformers.	No action
20	Page 48 of 88, what is the Tank Farm existing and projected future load listed?		Clarify Tank Farm loads in the discussion		The basis for the loads are documented in Attachment #11 appended to the PDF version of Revision D of the study. All the Attachments will be appended to the PDF version of revision 0 of the study.	No action
21	Page 49 of 88, and page 50 item 6, The 230KV utility option 10 does not meet the criteria set forth in the statement of work of deliver of 70MW minimum. This option will require the shared control of the WTP with the Tank Farm. This might required a contract change to implement the necessary interface and operation of the WTP and Tank Farm and utility.		Evaluate operability, reliability and maintainability and documents that need to be changed at the three levels of Tank Farm, WTP and utility.		There are no operability issues between the WTP, TF and the utility. MSA is the sole operator of the 13.8 KV breakers in all of the Hanford 230 KV substations. MSA normal operating procedures cover notification of the users (WTP, TOC, PRC, etc.) before any scheduled non-emergency operations of the 13.8 KV breakers. This is exactly the same situation that exists in the A6 Substation at present. WTP authorization basis documents will need to be revised to varying degrees for all of the options.	No action

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
					MSA maintains the 230 KV substations regardless of who the user is. Maintenance costs are not included in the ROM cost estimates.	
22	General comment: The evaluation provided schedule for each option, does the time provided include everything like time to go through the budget cycle or the time and the clock start when the contract is awarded?		Provide clarification		The ROM schedules include only the EPCC time frame, which does not include the DOE mandated budgeting and authorization cycles. In short the schedules start AFTER ORP has authorized the contractors to commence work. See page 18 for details.	No action
23	General comment: Was the evaluation considered any outages and impact to WTP when selected different options.		A statement need to be added for the owner of the report to consider outage duration to WTP during option selection.		The schedules include no consideration of duration of outages to implement an option. Refer to Meeting Minutes August 24, 2010, topic 7 Duration of Outages to WTP for documentation of the issue.	No action
24	General Comment: was any consideration given for the protection of the transformers of different substations.		Add in the Advantage/Disadvantage section of the report that upon loss of one 100MVA transformer and switching to 62MVA transformer, the loads need to be evaluated before the switching is completed and the circuit is energized. Also, a		The evaluation of loading on any Hanford 230 KV substation transformers primarily resides with MSA. Switching operations will be based on criteria developed by MSA, with input from the users. Design of interlocks is a detailed design action to be	No action

12. Item	13a. Comments	13b. Basis	13c. Recommendation	14. Reviewer Concurrence Required (Y or N)	15. Disposition (provide justification if **NOT** accepted)	16. Status
			mechanical interlock should be provided.		completed by the AE contracted to perform the detailed engineering analysis of the chosen power option.	
25	Page 58 of 88, second sentence state "Option 1 will require two different contractual authorities (Hanford 230Kv System Operator and the WTP Operator) to have shared authority of building 87 main switchgear, Why, Explain.		Provide clarification why shared authority is needed.		MSA also noticed this issue. Option 1 will be revised to eliminate the issue. After the change has been picked up there will be no contractual issues differing from those already documented in ICD-11.	Picked up comment
26	Page 58 of 88, you provided reference for the Is.c primary of 10722.7A, what is the reference for the secondary of 28,000A		Verify and provide the reference.		Added reference as requested.	Picked up comment

APPENDIX F

PROJECT MEETING MINUTES

- May 21, 2010, 1300 hours
  - 2440 Stevens Center Drive, 2701 Conference Room
  - Monthly Status Meeting – Analysis of Power Delivery to WTP
  - number of pages 5

- June 14, 2010, 1100 hours
  - 2440 Stevens Center Drive, 2701 Conference Room
  - Monthly Status Meeting – Analysis of Power Delivery to WTP
  - number of pages 5

- June 29, 2010, 1100 hours
  - 2440 Stevens Center Drive, 2701 Conference Room
  - Scope and Schedule Meeting – Analysis of Power Delivery to WTP
  - number of pages 11

- July 13, 2010, 1000 hours
  - Building 2101M East Area, Bijou-Cosmos Room
  - Briefing to MSA on Analysis of Power Delivery to WTP Engineering Study
  - number of pages 4

- July 22, 2010, 0700 hours
  - Building 2101M East Area, Bijou-Cosmos Room
  - Analysis of Power Delivery to WTP Engineering Study Options Presentations
  - number of pages 36

- August 24, 2010, 0800 hours
  - Building 2101M East Area, Bijou Room
  - Design Review of Revision D of Analysis of Power Delivery to WTP Engineering Study
  - number of pages 4

Meeting Minutes

Chairperson: Richard Ziegenbein

Meeting: May 21, 2010, 1300 hours

Location: 2440 Stevens Center Drive, 2701 Conference Room

Purpose: Monthly Status Meeting – Analysis of Power Delivery to WTP

Prepared by: Richard Ziegenbein 5/25/10

1. **Safety Topic** – Richard reminded everyone that May is National Electrical Safety Month. According to the Consumer Product Safety Commission, electrical extension cords are a leading cause of fires, injury and death. According to the CPSC:
   - 3,300 residential fires caused by extension cords, killing and injuring over 300 people,
   - More than half of the injuries involve fractures, lacerations, contusions, or sprains caused by people tripping over the extension cords,
   - Continual use of the cords can degrade the insulation causing shock or fire,
   - Consider adding more outlets if many extension cords are used.

2. **Introduction of Personnel** – All attendees introduced themselves with particular attention paid to the Senior Electrical Engineer, Jeremy Wilkins. Attendees included:

Mazen Al-Wazani	Mike Mache	Marshall Miller
Corbun Babel		Zak Schatz
Janet Diedeker		Martin Wheeler
Randall Krekel		Jeremy Wilkens
Gary Olsen		Richard Ziegenbein

3. **Project Status** – Richard reminded everyone that the study efforts are being conducted per the "SCOPE OF WORK AND METHODS OF ACCOMPLISHMENT FOR INCREASING POWER DELIVERY TO THE WTP". The status of the significant activities was discussed.

4. **Project Schedule** – A detailed project schedule was presented by Richard to Mazen, completing the requirement to deliver a detailed schedule within two weeks, deadline of May 25, 2010, of DOE ORP approval of the project scope and methods of accomplishment. Richard will revise the detailed schedule to include comments provided by Mazen on the Phase I and Phase II SKM Power Tools for Windows software analysis of the 230 KV Hanford Loop.

5. **Identification of Future Projects** – Phase II of the analysis requires identifying future loads (see scoping document dated 4/20/2010) that the Hanford Site 230 KV system must support. Martin will set up a meeting between ORP and WRPS to facilitate the identification of appropriate baseline future projects and future initiative projects that will be the basis of the future loads.

6. **MSA Support Documentation** – Mike indicated that MSA intended to provide the cost estimate on support services to WRPS by May 25, 2010. Richard described several of the support documents required, such as vendor data on the A6 Substation 62 MVA transformer and the Building 251E 13.8 KV switchgear. On Monday, May 24, 2010, Mazen provided Richard with photographs of the 62 MVA transformer and transformer nameplate. On Tuesday, May 25, 2010, Mike provided Richard with the cost estimates on support services

7. **Hanford 230 KV System and BPA Rate Information** – Randy took the action to provide Richard documentation on the Hanford 230 KV system equipment operations, BPA metering locations and the BPA rate structure. On Monday, May 24, 2010, Randy provided Richard the following documents:
    - USDOE – RICHLAND, Customer #10426, Meter Diagram \METERDIAGRAM\WALLAWALLA\USDOERICHLAND1_Meter.skf
    - Electrical 230 KV Single Line Switching Diagram, H-5-102
    - Bonneville Power Administration Transmission Services, 2010 Transmission and Ancillary Service Rate Schedules
    - 2010 Wholesale Power and Transmission Rate, WP-10-A-02-AP02.

8. **Overview of Options** – Richard reminded everyone that the scope of the project is based on providing at least 70 MW of power under worst case. Those options that do not meet these requirements will not be analyzed. The input to the options include:
    - 100 MVA transformers
    - 64 MVA transformers
    - 4,000 A 13.8 switchgear in Building 251E at A6 Substation
    - Fifth Feeder – WTP construction power
    - Power factor correction.

9. **Requested WTP Documents** – The WTP documents requested by Richard in Monday, May 10, 2010, were provided by Mazen in a CD. A paper copy of the WTP Power System Load Analysis, 24590-WTP-E1C-MVE-00004, Rev E, including the large format drawings were also provided by Mazen to Richard. The CD included copies of the following documents:
    - 24590-BOF-E1-MVE-00001, Rev 6 BOF Facilities Power Distribution (MVE) Main Single Line Diagram
    - 24590-WTP-AHJ-E-08-0004 Percent loading factor
    - 24590-WTP-DB-ENG-01-001, Rev 10, Basis of Design
    - 24590-WTP-DC-E-01-001, Rev 7 Electrical Design Criteria
    - CCN 204692 Potential Changes in Risk Items
    - CCN 163262 DOE Transformer information
    - CCN 174183 Maximum Recorded Utility Grid Voltage
    - CCN 199010 0.46 KV motor nameplate data

- CCN 199915 Alarms on A6 transformer load
- CCN 199915 Operation of Standby load
- CCN 200979 Meeting Minutes of electrical load analysis of non-running standby loads
- CCN 200979 Referenced mechanical design documents
- CCN 201338 Operating loads
- CCN 201344 Use of actual design loading
- CCN 201345 Non-Running Standby loads is Chiller facility 13
- CCN 201354 To-Be-Designed Buildings load estimate
- CCN 202428 Design Philosophy for Standby BOF PSA Compressor
- CCN 204691 Non-Running Motor Loads
- CCN 206042 Impact of Standby Motor Operation on the Electrical Load Flow Analysis

Attachment: May 21, 2010 Meeting Sign-in Sheet

May 21, 2010, 1:00 pm

2440 Stevens Drive, 2701 Conference Room

NAME	SIGNATURE	E-MAIL ADDRESS	PHONE NUMBER
Al-Wazani, Mazen	Mazen	Mazen_G_Al-Wazani@orp.doe.gov	(509)376-4784
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Wilkins, Jeremy		Jeremy_D_Wilkins@rl.gov	(509)551-7917
Schatz, Zak		Zakary_M_Schatz@rl.gov	(509)376-6411
Ziegenbein, Richard		Richard_S_Ziegenbein@rl.gov	(509)376-0991
Mike Marshall		Marshall_S_Mike@RL.Gov	509-942-4175

Meeting Minutes

Chairperson: Richard Ziegenbein

Meeting: June 14, 2010, 1100 hours

Location: 2440 Stevens Center Drive, 2701 Conference Room

Purpose: Monthly Status Meeting – Analysis of Power Delivery to WTP

Prepared by: Richard Ziegenbein

1. **Meeting Attendees**

Mazen Al-Wazani	Russell Harwood	Martin Wheeler
Corbun Babel	Randall Krekel	Jeremy Wilkens
Ernie Hamm	Zak Schatz	Richard Ziegenbein

2. **Project Status** –The Phase I report is still on track for June 30, 2010 transmittal to ORP. The deliverable of the SKM analysis of the 230 KV system is at risk. The SKM report has not been made available due to ongoing negotiation efforts with MSA on the level of support required for the entire analysis effort. Richard discussed an option of performing a maximum capacity calculation of the 230 KV Hanford system and comparing the result with the projected loads on the 230 KV system. Mazen indicated that it is critical to have the SKM analysis of the 230kV system that will include the load flow, short circuit and voltage drop analysis. He also, indicated the report will not be completed without the SKM analysis including estimate of the tank farm loads and future loads. He also, indicated if WRPS at risk of meeting the June 30, 2010 or not having complete report including SKM analysis, WRPS needs to communicate that with a letter to DOE-ORP for any changes to the deliverable required by WRPS letter WRPS-1000326 R2. Mazen also indicated that is critical to have MSA and BNI to review the report and provide their comments formally. Randy Krekel informed the group that DOE has negotiated a Tier 1 billing structure with BPA on the first 92 MW of load. 70 MW covers a previously projected WTP load. 22 MW covers a previously projected Hanford Site wide load.
   Update – On June 21, 2010 MSA accepted WRPS contract #36523, release 38 in technical support of the Analysis of Power Delivery to WTP report. On June 21, 2010 MSA was tasked by WRPS to provide the SKM files, impedance drawing and review comments on the Phase I report.

3. **Project Schedule** – An updated project schedule, dated June 14, 2010 was presented by Richard to Mazen. A revised copy of the schedule was e-mailed to Mazen the afternoon of June 21, 2010.

4. **Review of Phase I of the Report** – The Phase I report has undergone an extensive internal URS review. Richard passed out CDs that contained files of the Phase I Report, attachments and referenced documents. Richard asked everyone to provide review comments by using "track changes" and to e-mail the document to him by close of business Friday, June 18, 2014.
   Update – Review Comments were received from: DOE-RL on June 15, 2010 via track changes, DOE-ORP provided most of their comments on June 18, 2010, 8 more additional comments were provided on June 21, 2010 via the Review Comment Record (RCR) form A6400-090.1 and WRPS Central Engineering on June 21, 2010 via track changes. WRPS will disposition the review comments via the RCR process and issue the Phase I Report as a final PE stamped document on June 30, 2010.

5. **Review of Options** – Richard briefly described the eight options contained within the report. Three of the options are highly rated and key features of each option were presented to the group. See attachment for details on the eight options.

6. **Requested WTP Documents** – The WTP documents requested by Richard in Thursday, May 27, 2010, were provided by Mazen in a CD on Wednesday, June 2, 2010. The CD included copies of the following documents:
   - 24590-BOF-E1-MVE-00002, Rev 9, Switchgear Building 13.8KV MVE-SWGR-87001A & 87001B Single Line Diagram
   - 24590-BOF-E1-MVE-00003, Rev 8, Switchgear Building 13.8KV MVE-SWGR-87002A & 87002B Single Line Diagram
   - CCN 200152
   - CCN 196111
   - CCN 194415

Attachment: June 14, 2010 Meeting Sign-in Sheet

Listing of Eight Options Considered

June 14, 2010, 11:00 am

2440 Stevens Drive, 2701 Conference Room

NAME	SIGNATURE	E-MAIL ADDRESS	PHONE NUMBER
Al-Wazani, Mazen	Mazen G. Al-Wazani	Mazen_G_Al-Wazani@orp.doe.gov	(509)376-4784
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Hamm, Earnest	Earnest Hamm	Earnest_R_Hamm@rl.gov	(509)372-0310

Wheeler, Martin		Martin_Wheeler@rl.gov	(509)376-2099
Wilkins, Jeremy		Jeremy_D_Wilkins@rl.gov	(509)551-7917
Schatz, Zak		Zakary_M_Schatz@rl.gov	(509)376-6411
Ziegenbein, Richard		Richard_S_Ziegenbein@rl.gov	(509)376-0991

RECOMMENDED OPTIONS

Replace transformers with 100 MVA transformers
Directly feed WTP Building 87 switchgear
Does not meet ICD 11 interface boundaries
$10.5 M 2 years

Replace transformers with 100 MVA transformers
Replace switchgear with two 4,000 A switchgear
Meets ICD 11 interface boundaries
$12.3 M 2 years

Procure spare 62 MVA transformer
Utilize IEEE Std C57.91 loading
Does not meet single transformer loading
$1.5 M 1 year

OPTIONS NOT RECOMMENDED

Replace transformers with 100 MVA transformers
Add two 3,000 A switchgear
Build second A6 substation building
$18.4 M 2 years

Add two 62 MVA transformers
Replace switchgear with two 4,000 A switchgear
Build second A6 substation building
No cost estimate prepared due to cost of second building

Add two 62 MVA transformers
Add two 3,000 A switchgear
Build second A6 substation building
No cost estimate prepared due to cost of second building

Add 62 MVA transformer
Build second A6 substation building
No cost estimate prepared due to cost of second building

Existing A6 Substation
Two 62 MVA transformers
Two 3,000 A switchgear
Utilize IEEE Std C57.91 loading
Does not meet single transformer loading

Meeting Minutes

Chairperson: Richard Ziegenbein

Meeting: June 29, 2010, 1100 hours

Location: 2440 Stevens Center Drive, 2701 Conference Room

Purpose: Scope and Schedule Meeting – Analysis of Power Delivery to WTP

Prepared by: Richard Ziegenbein

1. **Meeting Attendees**

Mazen Al-Wazani	Gary Olsen	Earnest Hamm
Susan Johnson	Garth Reed	Richard Ziegenbein

2. **Phase I Report** –The Phase I report scope will be revised per:
   - Use of an alternate calculation versus the SKM software to determine the impact of WTP load on the Hanford 230 KV system. The alternate calculation shall provide an answer to ORP whether the Hanford 230kV system, including the feed to A6 substation, has sufficient capacity to support the current WTP projected load of a minimum 70MW. The alternate calculation will take into consideration the different options provided as results of the evaluations in the Phase I report..
   - Existing and Future Tank Farm and Initiatives loads will be included in the alternate calculation to determine total impact to 230 KV system
   - Alternate calculation will cover only the MVA and A-6 feeder capability of the Hanford 230 KV loop. The complete analysis of impacts to the 230 KV loop will be performed in the Phase II report and will include the SKM Load Flow, Voltage Drop and Comprehensive Fault Analyses.
   - MSA review comments will be incorporated
   - Report will be PE stamped and delivered to ORP on or before July 26, 2010

3. **Future Tank Farm Projects** – Richard discussed the purpose of June 22, 2010 meeting with Stacy Charboneau, Richard Ziegenbein and Marshall Miller. The result of the meeting is a list of future projects approved by ORP for inclusion in the load flow analyses. The projects are documented in a June 22, 2010 e-mail. The projects are composed of three categories:
   - Tank Farms Waste Feed Delivery and Safe Storage
   - Existing Baseline Future Projects
   - Future Initiative Projects.

   The projects are also divided into two cases: Baseline Case and Alternative Case. Richard also described the ongoing efforts to determine and document the electrical loads associated with

the future projects. Richard will distribute for review a spreadsheet containing the projects, electrical loads, timing of the loads and the references to documentation supporting each electrical load.

4. **MSA Contract** – The status of the contract between WRPS and MSA is as follows:
    - MSA accepted the WRPS contract on June 21, 2010, 8:18 AM
    - MSA committed to providing services for each authorized service within 10 business days of the authorization
    - WRPS authorized MSA on June 21, 2010, to provide the Hanford 230 KV and 13.8 KV SKM data files
    - MSA provided the SKM data files on June 21, 2010
    - WRPS authorized MSA on June 21, 2010, to provide review comments on a draft copy of the Phase I report.
    - On June 30, 2010, MSA was provided an updated copy of the draft copy of the Phase I report to facilitate the review of the above mentioned alternate calculation.

5. **Phase II Report** – Report will be PE stamped and delivered to ORP on or before September 16, 2010. Delivery date of September 16, 2010 is contingent upon receiving all review comments no later than August 27, 2010 and resolving received comments no later than September 2, 2010. The scope of work is unchanged. The group discussed two cases to be considered in the report:

    Case 1 – WTP Phase I report power supply recommended option and the Baseline Case of Future Tank Farm Projects

    Case 2 – WTP Phase I report power supply recommended option and the Alternative Case of Future Tank Farm Projects.

    Note: The Baseline Case and Alternative Case are defined in the above referenced June 22, 2010 e-mail as follows:
    - **Baseline Case**
        - Tank Farm Upgrades (Waste Feed Delivery and Safe Storage)
        - Integrated Disposal Facility
        - Interim Hanford Storage Facility
        - Secondary Waste/Effluent Treatment Facility (ETF) Upgrades
        - Second LAW
        - Wiped Film Evaporator Mobile Unit
        - B/T Farm Special Waste Retrieval and Packaging
        - Tank Waste Operations Center
        - Aluminum Reduction Facility (ARF)

- **Alternative Case**
    - Tank Farm Upgrades (Waste Feed Delivery and Safe Storage)
    - Integrated Disposal Facility
    - Interim Hanford Storage Facility
    - Secondary Waste/Effluent Treatment Facility (ETF) Upgrades
    - East Supplemental Pretreatment Facility (SCIX & RMF)
    - East Supplemental Treatment Facility I (FBSR)
    - East Supplemental Treatment Facility II (FBSR)
    - East Post Supplemental Treatment Encapsulation
    - West Supplemental Pretreatment Facility (SCIX & RMF)
    - West Supplemental Treatment Facility (FBSR)
    - West Post Supplemental Treatment Encapsulation
    - Wiped Film Evaporator Mobile Unit
    - B/T Farm Special Waste Retrieval and Packaging
    - Tank Waste Operations Center

6. **SKM Load Flow Analysis** – Richard described the SKM analysis that will be performed during the Phase II report. The SKM Power Tools for Windows (PTW) product that will be used in the analysis is DAPPER. The analysis will consist of the following DAPPER Studies:
    - Load Flow
    - Voltage Drop
    - Comprehensive Fault Analysis.

7. **Alternate Calculations** – Richard described the process behind the alternative calculation. Review comments were received from Mazen and these will be incorporated into the Phase I report. Richard agreed to send an e-mail to RL requesting confirmation that BPA is not wheeling power through the Hanford 230 KV system.

8. **Review Comment and Resolution (RCR)** – Review comments will be dispositioned per the WRPS RCR process and included in the Document Release Form developed for each Phase I and Phase II report.

Attachment: June 29, 2010 Meeting Sign-in Sheet
June 22, 2010 2:43 PM email
PTW DAPPER_A.pdf

June 29, 2010, 11:00 am

2440 Stevens Drive, 2701 Conference Room

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JOHNSON, SUSAN		SUSAN_C_JOHNSON@ORP.DOE.GOV	(509) 373-7917

From: Ziegenbein, Richard S
To: Charboneau, Stacy L
Cc: Miller, Marshall S
Subject: FUTURE PROJECTS - ANALYSIS OF POWER DELIVERY TO WTP
Date: Tuesday, June 22, 2010 2:46:00 PM

Stacy,

After a discussion with Terry Sams, I added an encapsulation effort in the supplemental treatment projects. I propose that the following lists be used to support the power study effort. Do you concur?

BASELINE CASE
Tank Farm Upgrades (Waste Feed Delivery and Safe Storage)
Integrated Disposal Facility
Interim Hanford Storage Facility
Secondary Waste/Effluent Treatment Facility (ETF) Upgrades

Second LAW

Wiped Film Evaporator Mobile Unit
B/T Farm Special Waste Retrieval and Packaging
Tank Waste Operations Center

Aluminum Reduction Facility (ARF)

ALTERNATIVE CASE
Tank Farm Upgrades (Waste Feed Delivery and Safe Storage)
Integrated Disposal Facility
Interim Hanford Storage Facility
Secondary Waste/Effluent Treatment Facility (ETF) Upgrades

East Supplemental Pretreatment Facility (SCIX & RMF)
East Supplemental Treatment Facility I (FBSR)
East Supplemental Treatment Facility II (FBSR)
East Post Supplemental Treatment Encapsulation
West Supplemental Pretreatment Facility (SCIX & RMF)
West Supplemental Treatment Facility (FBSR)
West Post Supplemental Treatment Encapsulation

Wiped Film Evaporator Mobile Unit
B/T Farm Special Waste Retrieval and Packaging
Tank Waste Operations Center

Richard Ziegenbein
Washington River Protection Solutions
WTP Interface Management Lead
509 376 0991 office
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1200 Jadwin (347) MS E6-30
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SKM Power*Tools
ELECTRICAL ENGINEERING SOFTWARE

PTW DAPPER®

DAPPER® Studies

DAPPER is an integrated set of modules for Three-Phase Power System Design and Analysis including rigorous load flow and voltage drop calculations, impact motor starting, traditional fault analysis, demand and design load analysis, feeder, raceway and transformer sizing, and panel, MCC, and switchboard schedule specification.

Benefits

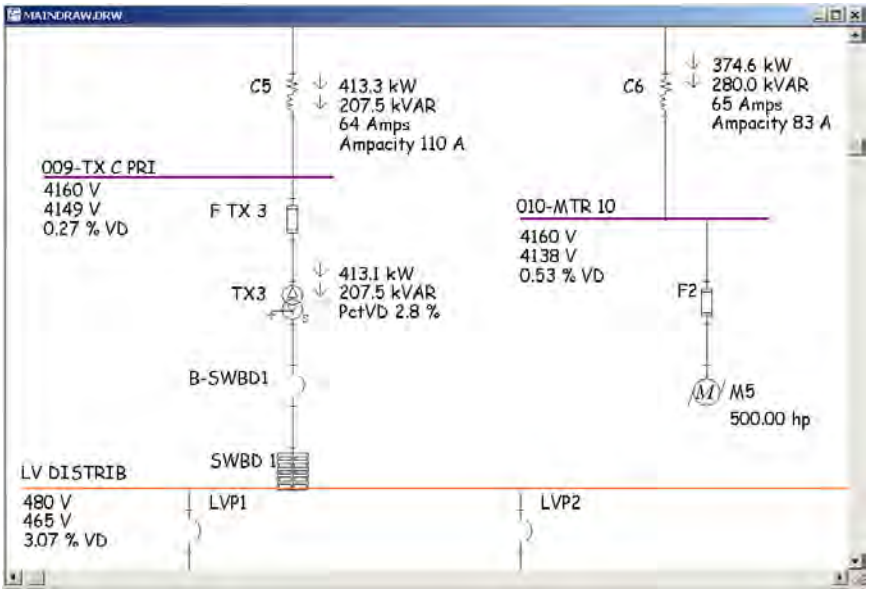
- Generate better designs by comparing alternatives quickly.
- Improve accuracy with DAPPER's rigorous solution methods.
- Save time by sharing a common project database and interface.
- Improve consistency with standard design libraries.
- Design safer systems by comparing calculations with short circuit and continuous ratings.
- Communicate designs effectively with presentation quality graphics, reports, and equipment schedules.

Load Flow/Voltage Drop

With DAPPER, users can calculate the voltage drop on each feeder and transformer branch, voltage on each bus, projected power flow, and losses in the power system.

This program may be used for conventional voltage drop analysis, loss analysis, power factor studies, capacitor placement, long-line charging effects, impact loading for motor starting studies, generator sizing, and for cogeneration analysis.

With DAPPER, a single load flow program models loop and radial power systems. Double precision sparse matrix current injection solutions are used for faster, more accurate convergence. This allows for better modeling of ill-conditioned systems.



Load flow study results are automatically displayed on the oneline diagram and in tabular report form.

DAPPER® Load Flow Features

- Models radial, loop, and multiple independent systems.
- Models utility and generator equivalent impedance calculated from short circuit duty.
- Models up to 50 utilities/swing bus generators.
- Models up to 400 regulated and unregulated co-generators.
- User definable per unit driving voltage at each utility and swing bus generator.
- Models transformer primary and secondary taps and off nominal rated voltages.
- Model load tap change transformer and zig-zag transformer.
- Model static var compensator, dynamic var compensator, and power factor correction equipment.
- Full transmission line modeling with built in line parameter calculators.
- Models any combination of motor and non-motor loads with global and/or local load factors.
- Models any combination of constant kVA, constant impedance and constant current loads.
- Reports bus voltage, voltage angle, and voltage drop at each bus.
- Reports branch voltage drop, power factor, and power flow in kW, kVAR, kVA, and Amps.
- Reports branch loss in kW, kVAR, kVA, and total system losses.
- User definable report criteria for bus and branch voltage drops.
- Percentage voltage drops based on system voltage per ANSI standards.
- Double precision calculations improve solution accuracy.
- Rapid solution convergence.
- Suitable for impact motor starting, capacitor placement and power factor studies.
- Load flow results validated to match with benchmark calculations and IEEE examples.

Comprehensive Fault Analysis

The DAPPER Comprehensive Fault Analysis program provides a network solution of three-phase, single-line to ground, line-to line, and double line to ground fault currents; RMS momentary fault currents; asymmetrical fault duties at three, five, and eight cycles; the positive, negative, and zero sequence impedance values between each fault location, and contributions from utilities, generators, and motors. At each fault location, the direction, X/R, and magnitude of fault currents are reported, thus providing a clear view of the conditions that exist during the fault.

Fault Location Bus Name	Bus Voltage	3-Phase Amps	3-Phase MVA	3-P X/R	SLG Amps	SLG MVA	SLG X/R	Mom Amps	--3P Asym Amps-- 3 Cycle	5 Cycle	8 Cycle
001-UTILITY CO	69,000	4,632	553.55	25.32	3,715	147.99	4.68	7,412	5,580	5,004	4,718
002-TX A PRI	69,000	1,847	220.73	14.93	1,169	46.57	9.60	2,809	1,989	1,874	1,849
003-HV SWGR	13,800	7,956	190.17	10.86	8,478	67.55	9.07	11,588	8,200	7,980	7,957
004-TX B PRI	13,800	7,770	185.71	5.48	8,157	64.99	4.39	9,937	7,778	7,770	7,770

DAPPER® Fault Analysis Features

- Symmetrical and Asymmetrical values reported at 1/2, 3, 5, 8, and 30 cycles.
- Asymmetrical values reported at user selected fault time.
- Asymmetrical values reported as peak or RMS values.
- Models two and three winding transformer taps, phase shift, and off nominal rated voltages.
- Asymmetrical exponential DC decay is based on X/R to each contribution.
- Reports Thevenin equivalent impedance and X/R at the faulted bus.
- Detailed and summary reporting options.
- Reports bus voltages and branch flows throughout the system for each faulted bus.
- Reports phase or sequence current and voltage.
- Reports ground return current for double line to ground faults.
- Models transformer and generator neutral grounding impedances.
- User-defined pre-fault voltage at each bus, using load flow results, no load with tap, or user-defined value.

Demand Load Analysis

The DAPPER Demand Load Analysis program provides a consistent summary of the loads throughout the power system. Connected, demand, and design loads are calculated for each load bus. All load calculations are based upon the global application of demand and design factors and the complex addition of loads, to properly account for the differences between load types. This method assures complete compliance with local and national electric code requirements while permitting flexibility in design for special applications.

The demand load information can be used directly by the DAPPER sizing and load flow modules. This data calculation procedure greatly simplifies the user interface while providing rigorous analytical results.

DAPPER® Demand Load Analysis Features

- Reports Connected, Demand, and Design loads.
- All load calculations account for individual load power factors.
- Automatically creates input load data for Load Flow and Voltage Drop Studies.
- Automatically creates loads for sizing feeders and transformers.
- System demand loads calculated using methods recognized by the NEC.
- Automatically tracks largest motor fed by each bus to meet NEC requirements.
- Automatic compliance with NEC and local codes for multi-level load diversity.
- Sensitivity studies, future load growth studies and load diversity studies by scaling load factors globally.
- "What if" analysis of loading conditions, i.e. light loading versus normal loading, or winter versus summer loading.
- Meet utility company requirements for providing a load summary by load type for connected, demand, and design loads at each utility bus.
- Generate sufficient information for sizing feeders, transformers, and other elements of the power system.

LOAD DESCRIPTION TYPE	UNITS	CONNECTED LOAD	DEMAND LOAD	DESIGN LOAD	POWER FACTOR
GENERAL LOADS	KW	55.3	55.3	55.3	
	KVAR	36.9	36.9	36.9	
	KVA	66.5	66.5	66.5	83.20 LAGGING
HEAT	KW	158.2	158.2	197.7	
	KVAR	0.0	0.0	0.0	
	KVA	158.2	158.2	197.7	100.00 UNITY
LTS	KW	216.8	216.8	271.0	
	KVAR	95.6	95.6	119.5	
	KVA	236.9	236.9	296.1	91.50 LAGGING
OFF EQ	KW	7.1	7.1	7.1	
	KVAR	4.4	4.4	4.4	
	KVA	8.3	8.3	8.3	85.00 LAGGING
ENERGY AUDIT Z	KW	237.5	237.5	237.5	
	KVAR	-3603.9	-3603.9	-3603.9	
	KVA	3611.7	3611.7	3611.7	-6.58 LEADING
KVA TYPE MTR	KW	12122.4	12122.4	12122.4	
	KVAR	5792.5	5792.5	5792.5	
	KVA	13435.2	13435.2	13435.2	90.23 LAGGING
LARGEST KVA MTR	KW	3885.4	3885.4	4856.8	
	KVAR	0.0	0.0	0.0	
	KVA	3885.4	3885.4	4856.8	100.00 UNITY
TOTAL LOADS	KW	16682.7	16682.7	17747.8	
	KVAR	2325.5	2325.5	2349.4	
	KVA	16844.0	16844.0	17902.7	
	% PF	99.0 LAGGING	99.0 LAGGING	99.1 LAGGING	

Feeder and Transformer Sizing

DAPPER will size feeder cables, ground wires, raceways, bus ducts, duct banks and transformers throughout the power system to the load requirements calculated by the Demand Load Analysis program.

Feeders are selected to meet user-defined criteria for conductor material, voltage level, insulation type, and environmental conditions. Transformer primary and secondary feeders are sized to the transformer full load as specified by the user. Feeders and transformers may be included, excluded or evaluated in the sizing study.

DAPPER® Feeder and Transformer Sizing Features

- AWG, Bus Duct, ACSR, or metric sizes may be used.
- Feeders and transformers with “Do Not Size” are evaluated for capacity.
- Feeder libraries permit user to include metric sizes and ampacity.
- Transformers can be sized to Demand or Design load.
- Option to comply with the IEE wiring regulations for international wiring installation.

		-----Raceway Information -----					----- Feeder Information -----				
Cable Name	From Bus To Bus	In/Out New/Exist.	Number Size	Duct Bank Material	Ground Size Neutral Size	Qty/Ph. Size	Conductor Insulation	Length (feet)	Ambient (deg C)	Design Load (Amps)	Derated Rating(Amps)
C1	003-HV SWGR	In	1	D-7	8	1	Copper	200	30	46	115
	004-TX B PRI	New	2 1/2"	Non-Magnetic	8	6	XLP				
C10	BLDG 115 SER	In	2	NONE	2	2	Copper	350	30	162	390
	026-TX G PRI	New	3"	Non-Magnetic	3	1/0	XLP				
C11	BLDG 115 SER	In	1	NONE	2	1	Copper	500	30	339	480
	025-MTR 25	Existing	5"	Non-Magnetic	3/0	500	XLP				
C12	022-DSB 2	In	4	NONE	3/0	4	Copper	100	30	937	1,140
	023-MTR 23	New	2 1/2"	Non-Magnetic	3/0	300					

Load Schedules

The DAPPER Load Schedule module provides detailed documentation of load fed through Panels, Motor Control Centers (MCCs) and Switchboards. Input is simplified through the use of libraries and copy and paste functions. The schedules can be displayed, printed, and exported in a variety of different formats.

DAPPER® Load Schedules Features

- Schedules are automatically updated with available short circuit values and sub-feed totals.
- Panel & switch board schedules are automatically generated from connected branch loads.
- MCC schedules can reference a default design library for automatic selection of feeder and raceway sizes, or the complete cable library for more detailed specification.

PANEL_S3

PANEL: PANEL S3	OC DEVICE TYPE: Breaker	ENCLOSURE: NEMA 1	MAINS(A): MLO	BUS RATING(A):	225
LOCATION: Penthouse	DEVICE FAMILY: Bolt On	MOUNTING: Flush	WIRING: 3-Phase 3-Wire	WITHSTAND(A):	10000
FED FROM: 016-H2A		VOLTAGE: 480		FAULT CURRENT(A)	7658
REVISION: 1			ITE		

OC AMPS P	NOTES	DESCRIPTION	DEMAND CODE	VA	CKT	PHASE LOADS VA A	B	C	CKT	VA	DEMAND CODE	DESCRIPTION	NOTES	OC AMPS P
0 3		019-H3A	NONE	41383	1	32535			2	58197	HEAT	Heater		100 3
""		""		-	3		32535		4	-		""		""
""		""		-	5			32535	6	-		""		""
0 3		L8	LTS	9700	7	7390			8	4157	LTS	Lights		20 1
""		""		-	9		7390		10	4157	LTS	Lights		20 1
""		""		-	11			7390	12	4157	LTS	Lights		20 1
0 3		L7	LTS	8000	13	6809			14	4157	LTS	Lights		20 1
""		""		-	15		6809		16	4157	LTS	Lights		20 1
""		""		-	17			6809	18	4157	LTS	Lights		20 1

ALL CONNECTED	KVA	AMPS	* PHASE TOTALS	VA	AMPS	BUS TOTALS	KVA	
TOTAL CONNECTED	139.74	168.1	* A-N	46578.6	168.1	CONNECTED	139.74	DATE: 17 Apr 2003
TOTAL DEMAND	139.74	168.1	* B-N	46578.6	168.1	DEMAND	139.74	TIME: 09:55:28
TOTAL DESIGN	172.71	207.7	* C-N	46578.6	168.1	DESIGN	172.71	

Panel is locked, use key #17-C

Systems Analysis, Inc.
P.O. Box 3376
Manhattan Beach, CA 90266
800.232.6789
www.skm.com
sales@skm.com

Meeting Minutes

Chairperson: Richard Ziegenbein

Meeting: July 13, 2010, 1000 hours

Location: Building 2101M East Area, Bijou-Cosmos Room

Purpose: Briefing to MSA on Analysis of Power Delivery to WTP Engineering Study

Prepared by: Richard Ziegenbein

1. **Meeting Attendees**

DOE	MSA	WRPS	BNI
Mazen Al-Wazani	Scott Baker	Jeremy Wilkins	Charles Chan
Randall Krekel	Cris Carlson	Richard Ziegenbein	
Garth Reed	Calvin Dudney		
	Mike Hache		
	Sheree Schweiger		
	Jacob Smith		
	Jim Uecker		

2. **MSA Review Comments** – MSA stated they had been unable to develop review comments on the A6 Substation options due to insufficient information contained within the study. Richard said the options were conceptual, hence were not intended to be fully detailed. A meeting was requested by MSA so that WRPS can provide additional technical information on options that MSA believes are truly viable with respect to MSA's experience in dealing with Bonneville Power Administration (BPA) requirements and MSA's numerous years of electrical utility experience. MSA also requested that during the meeting they will present options they wish to be considered in the study and WRPS may ask questions related to these MSA options. After consideration of schedules and priorities, Scott will propose a time, date and location for the meeting. Mike will relay this information to Richard for WRPS concurrence. The meeting may take place late this week. MSA may provide the date when their review comments will be provided to WRPS.
   Note: On July 14, 2010 MSA proposed July 22, 2010 for the meeting date. WRPS accepted the meeting date. The meeting will be conducted in Building 2101M East Area, Bijou-Cosmos Room from 7:00 AM to 10:00 AM.
   Note: On July 19, 2010 MSA proposed providing options comments to WRPS on July 28, 2010. WRPS accepted the July 28, 2010 date.

3. **Inclusion of MSA Review Comments in Study** – WRPS acknowledges that MSA is the Hanford electrical utility (study Section IV Background, "The Hanford 230 kV electrical utility system is

administered by Mission Support Alliance (MSA) for DOE.") and as such the study would be enhanced by including MSA review comments. Richard stated that MSA review comments will be dispositioned per the WRPS RCR process and included in the Document Release Form developed for the study.

4. **Availability of Power from BPA** – MSA and Randy expressed concerns that BPA may not be willing or able to provide DOE-ORP with the additional power required to support the projected WTP and Tank Farm loads. Randy agreed to contact BPA to begin coordinating the additional load requirements. MSA and Randy agreed that, even though BPA must ultimately be involved with DOE in the selection of a recommended option, the study can proceed. Scott stated that MSA has sufficient knowledge of BPA preferences to insure that the recommended option may be acceptable to BPA.

5. **WTP 70 MW Projected Load** – MSA stated they felt the 70 MW projected load was excessive and options considering less than 70 MW should have been considered in the study. Richard stated that the tasking from ORP directed WRPS to perform analyses and determine viable options for increasing power delivery up to at least 70 MW under a worst case scenario. Jim asked if the 70 MW was an NEC load (connected) or an operational load. Charles stated that the 70 MW was composed of 53 MW of calculated operational demand load with a 15% contingency and 15% design growth.

6. **Review Comment and Resolution (RCR)** – Richard stated that review comments will be dispositioned per the WRPS RCR process and included in the Document Release Form developed for the study.

7. **Phase I Study Due Date** – WRPS informed DOE that the current June 26th due date was not going to be met based on MSA request for additional time to review the study, develop comments on the WRPS options and develop MSA options. A revised schedule date will be developed at a later point in time, reflecting MSA's schedule input.

Attachment:

Sign in sheet

July 13, 2010, 10:00 am

2101M, Bijou-Cosmos Rooms

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Meeting Minutes

Chairperson: Richard Ziegenbein

Meeting: July 22, 2010, 0700 hours

Location: Building 2101M East Area, Bijou-Cosmos Room

Purpose: Analysis of Power Delivery to WTP Engineering Study Options Presentations

Prepared by: Richard Ziegenbein

1. **Meeting Attendees**

DOE	MSA	WRPS	BNI
Mazen Al-Wazani	Scott Baker	Earnie Hamm	Charles Chan
Russell Harwood	Jane Boyd	Marshall Miller	
Randall Krekel	Mike Hache	Zak Schatz	
	Joe Popp	Jeremy Wilkins	
	Sheree Schweiger	Richard Ziegenbein	
	Daniel Sours		
	Jim Uecker		

2. **Purpose of the Meeting** – Richard stated that the purpose of the meeting is twofold:
   - WRPS to make presentations on the options in the existing study and MSA to ask detailed questions on these options
   - MSA to make presentations on new options which MSA desires to be addressed in the study and WRPS to ask detailed questions on these new options
   - Discuss the revised project schedule
   - Discuss the incorporation of review comments

3. **Inclusion of MSA Sponsored Options in the Study** – WRPS will address the MSA sponsored options into the study. Details on these options will be obtained from this meeting's presentations and written input from MSA. It is acceptable and preferable to receive the MSA written input via e-mail. The written input must be received by Wednesday, July 28, 2010 for inclusion into the study.
   Note: Mike provided, via a July 22, 2010 e-mail, PDF copies of the MSA presentation materials and documentation of the option that Randy discussed.

4. **Existing Study Options** – WRPS distributed handouts consisting of selected portions of the study to the meeting participants to aid in the discussion of the existing study options. The below options were presented by Jeremy and he answered questions from the meeting participants. Refer to attachment "URS Options.pdf" for additional information on the options.

- URS Option 1 - Upgrade Transformers, 60/80/100MVA; Upgrade Switchgear A-6 Substation; 4,000A
- URS Option 2 - Upgrade Transformers; 60/80/100MVA; add two 3,000A Switchgear & 1 new Switchgear building
- URS Option 3 - Add two Transformers; 37/50/62 MVA; upgrade A-6 Substation; 4,000A switchgear
- URS Option 4 - Add two Transformers; 37/50/62 MVA; and associated new switchgear; add two 3,000A Switchgear & 1 new Switchgear building
- URS Option 5 - Add one transformer; 37/50/62 MVA; and associated new switchgear vertical sections with 3,000A breakers; add 230kV primary breakers; add two 3,000A bus duct
- URS Option 6 - Warehoused Spare 37/50/62MVA Transformer
- URS Option 7 - Upgrade Transformers, 60/80/100MVA with 3 windings; Eliminate A6 Switchgear & direct feed power from transformers
- URS Option 8 - Remove the requirement of 100% Electrical Load Operations while on one Transformer
- URS Option 9 - Concurrent implementation of 5th feeder and capacitor banks

5. **Options Presented by MSA** – Mike made presentations and answered questions on the below options. Refer to attachment "Electrical Utilities Comments and Proposals.pdf" for additional information on the options.
    - URS Option 1 - comments
    - URS Option 5 - comments
    - URS Option 7 – comments
    - EU Option #1 – 1 each 62 MVA transformers, 2 each outdoor 13.8 KV breakers, 1 each 230 KV GCB, Swing Bus
    - EU Option #1A – 1 each 62 MVA transformers, 2 each indoor 13.8 KV breakers, 1 each 230 KV GCB, expand control building, Swing Bus
    - EU Option #2 – 1 each 62 MVA transformers, 2 each outdoor 13.8 KV breakers, 1 each 230 KV GCB, expand control building, Swing Bus and duplicate substation using 100 MVA transformers

6. **Options Presented by RL** – Meeting participants discussed the below option described by Randy. Refer to attachment "RL Option.pdf" for additional information on the option.
    - RL Option – Duplicate substation using 100 MVA transformers

7. **Review Comment and Resolution (RCR)** – Richard stated that review comments will be dispositioned per the WRPS RCR process and included in the Document Release Form developed for the study. Richard will meet with each reviewer to disposition each comment and will ask the reviewer to sign off on the RCR form.

8. **SKM Files Technical Data** – WRPS received initial SKM data files on June 21, 2010. Upon loading the files into the SKM software it was determined that the library files were missing and on June 30, 2010, WRPS requested MSA to supply the additional library files, which were received on July 12, 2010. When these library files were loaded into the SKM software, it was determined that they were incomplete in terms of existing load information and key electrical equipment ratings; for example, the substation 13.8 KV bus electrical ratings and the 230 KV breaker electrical frame size and trip set point information. This missing information was discussed with an MSA electrical utility engineer and he indicated that the project files had never been populated with the load flow information, because the Bonneville Power Administration performs the Hanford 230 KV system load flow analysis as a result of their being the Hanford 230 KV system operator. Mike confirmed that existing load information and key electrical equipment ratings were indeed missing and that MSA could supply, if so requested by WRPS, documents to determine these electrical ratings. WRPS would then enter that data into the SKM files. WRPS indicated that this extensive technical effort is outside of the original scope of work negotiated with ORP. As discussed during the meeting, the SKM load flow analysis tasking by ORP cannot be performed by WRPS without extensive technical research and data entry for the entire Hanford 230 KV and 13.8 KV systems. In response to this, WRPS proposes to continue developing the alternative manual calculation in Section XI of the report as a compensatory measure to determine if the Hanford 230 KV system can support the projected loads of the WTP and the Tank Farms and the impacts of these loads on the 230 KV system and the A6 and A8 Substations.

9. **Schedule impacts on WTP LBL commissioning due to revisions to A6 Substation** – Charles told the group that revisions to the existing A6 substation could impact the BNI schedule to commission the LBL portion of the WTP. Jeremy said that the ROM schedule to implement revisions to the A6 Substation are about two years, after ORP has authorized the A6 Substation project to move forward into the engineering, procurement, construction and commissioning phases.

10. **MSA Concerns on Selection Criteria** – Scott informed the meeting participants that MSA is concerned that many operational and non-technical criteria are not addressed in the report, examples include compliance, safety, Western Electricity Coordinating Council/ North American Electric Reliability Council (WECC/NERC) regulations, Conduct of Operations, Maintenance Interface, System Protection, etc.. Randy said that MSA should document these concerns in the written documentation that MSA has agreed to provide WRPS no later than July 28, 2010.

11. **Revised Study Schedule** – Richard stated that the Analysis of Power Delivery to WTP Engineering Study project has been rescheduled to accommodate the inclusion of MSA sponsored options, inclusion of MSA review comments on the revised study, and revision of study scope to replace the SKM analysis effort with a manual capacity impact calculation. Key activities and milestones of the revised schedule are as follows:

	July 22, 2010	Meeting to discuss WRPS and MSA options
	July 28, 2010	**MSA transmits to WRPS comments resulting from July 22, 2010 options meeting**
July 26, 2010	August 13, 2010	WRPS incorporates MSA options and comments into report
August 16, 2010	August 20, 2010	URS reviews report
	August 23, 2010	**submit report for Hanford community review and comment**
August 23, 2010	August 27, 2010	Hanford community prepares review comments on RCR form
	August 27, 2010	**Hanford community transmits review comments to WRPS**
August 30, 2010	September 2, 2010	WRPS dispositions Hanford community review comments
	September 6, 2010	Labor Day
August 30, 2010	**September 9, 2010**	**WRPS resolves review comments with Hanford community**
	September 10, 2010	Completed RCR forms transmitted to URS
September 10, 2010	September 15, 2010	URS approves and PE stamps report
September 10, 2010	September 15, 2010	WRPS prepares transmittal paperwork for report
	September 16, 2010	**WRPS transmits report to ORP**

Attachments:

Sign in sheet
URS Options.pdf
Electrical Utilities Comments and Proposals.pdf
RL Option.pdf

July 22, 2010, 7:00 am

2101M, Bijou-Cosmos Rooms

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Project Name: Analysis of Power Delivery to WTP

Project Number: 29906

URS Study Number: 17-05-110-001

WRPS Report Number: RPP-RPT-46992

ANALYSIS OF POWER DELIVERY TO THE WTP TO ACHIEVE A MINIMUM OF 70MW (76.4MVA)

PREPARED FOR

Department of Energy, Office of River Protection

URS Corporation

10800 Richmond Avenue

Houston, TX 77042

Revision: 0 Status: Final

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Table 1 Options Reviewed to Deliver a Minimum of 70MW (76.4MVA) to the WTP

Option	Description	Functionality	Reliability	Cost/Schedule
1	Upgrade Transformers, 60/80/100MVA; Upgrade Switchgear A-6 Substation; 4,000A	Meets the 70MW requirement, with 91.6% pf	Dual redundant line-up	$12.3M/ 2 Yr
2	Upgrade Transformers; 60/80/100MVA; add two 3,000A Switchgear & 1 new Switchgear building.	Meets the 70MW requirement, with 91.6% pf	Dual redundant line-up	$18.4M/ 2 Yr
3	Add two Transformers; 37/50/62 MVA; upgrade A-6 Substation ; 4,000A switchgear	Meets the 70MW requirement, with 91.6% pf	Dual redundant line-up	Not Considered Viable, due to insufficient space in A6 substation switchgear building
4	Add two Transformer; 37/50/62 MVA; and associated new switchgear; add two 3,000A Switchgear & 1 new Switchgear building.	Meets the 70MW requirement, with 91.6% pf	Dual redundant line-up	$17.5M/ 2 Yr
5	Add one transformers; 37/50/62 MVA; and associated new switchgear vertical sections with 3,000A breakers; add 230kV primary breakers; add two 3,000A busduct.	Meets the 70MW requirement, with 91.6% pf	Dual redundant line-up	Not Considered Viable, due to insufficient space in A6 substation switchgear building
6	Warehoused Spare 37/50/62MVA Transformer. Allows timely replacement of transformer at minimum cost.	Does NOT meet the 70MW requirement, with 91.6% pf	Dual redundant line-up	$1.5 M/1 Yr

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7	Upgrade Transformers, 60/80/100MVA with 3 windings; Eliminate A6 Switchgear & direct feed power from transformers.	Meets the 70MW requirement, with 91.6% pf	Dual redundant line-up	$10.5 M/2 Yr
8	Remove the requirement of 100% Electrical Load Operations while on one Transformer.	Does NOT meet the 70MW requirement, with 91.6% pf	Single redundant line-up	Not Considered Viable, due to ability to overload a single transformer as the result of automatic transfer switch operation.
9	Concurrent implementation of 5th feeder and capacitor banks	Does NOT meet the 70MW requirement at 97% pf.	Dual redundant line-up	Not Considered Viable, due to inability to meet 70MW requirement.

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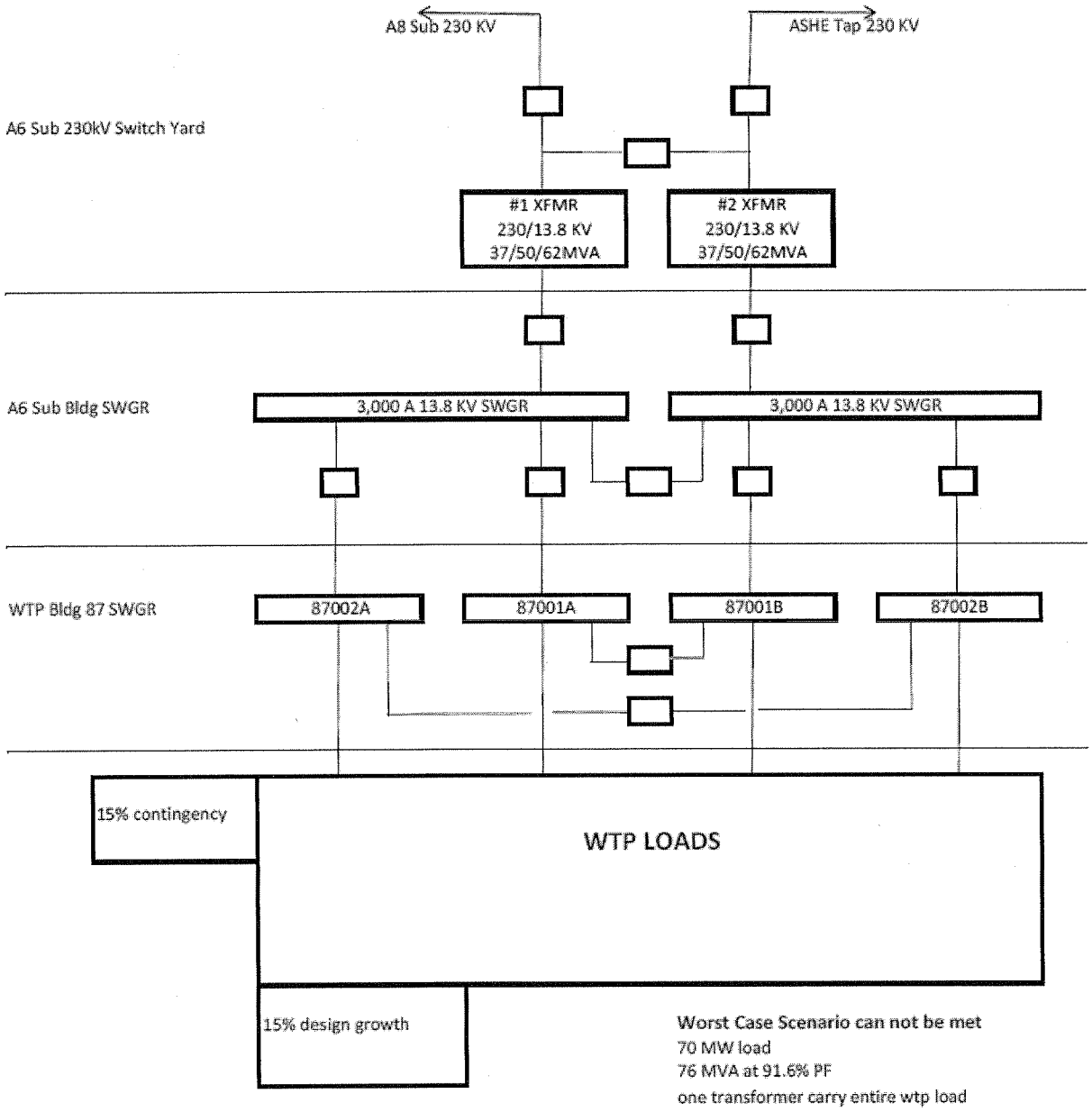
Figure #2 - 37/50/62MVA XFMRs and 3kA Swgr



EXISTING TWO 62 MVA TRANSFORMERS & 3,000 A BUS

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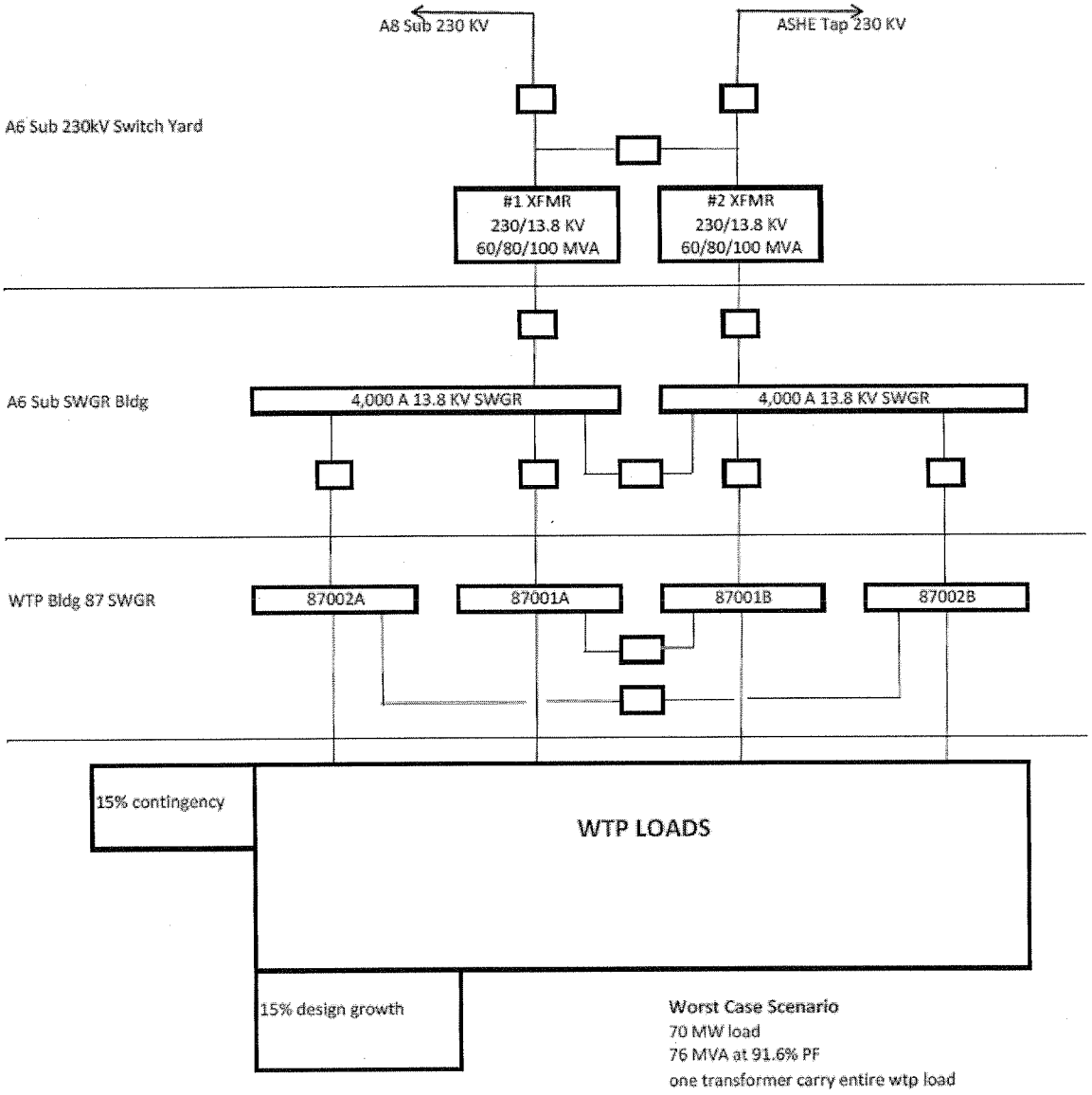
B. Option 1 – A6 Substation Electrical Equipment Upgrade

Figure #3 - 60/80/100MVA XFMRs, 2-4kA Swgr, and 1 Swgr Bldg



TWO 100 MVA TRANSFORMERS & 4,000 A BUS

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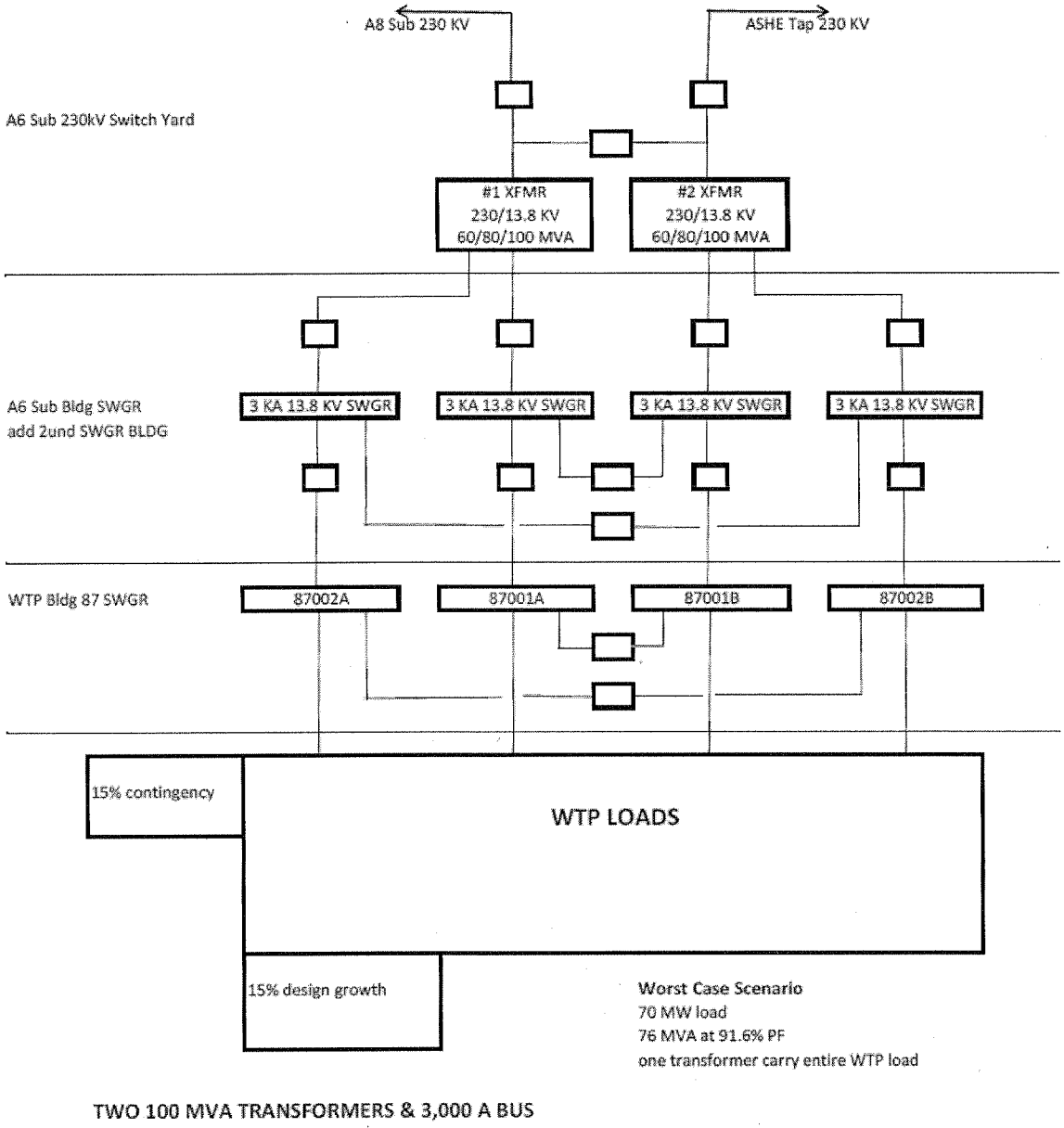
C. Option 2 – A6 Substation transformer Upgrade (3-winding), 2 New Switchgear, and Switchgear Building.

Note: Transformer primary winding rating shown

Figure #4 2-60/80/100MVA XFMRs, 4-3kA Swgr, and 2 Swgr Bldgs



TWO 100 MVA TRANSFORMERS & 3,000 A BUS

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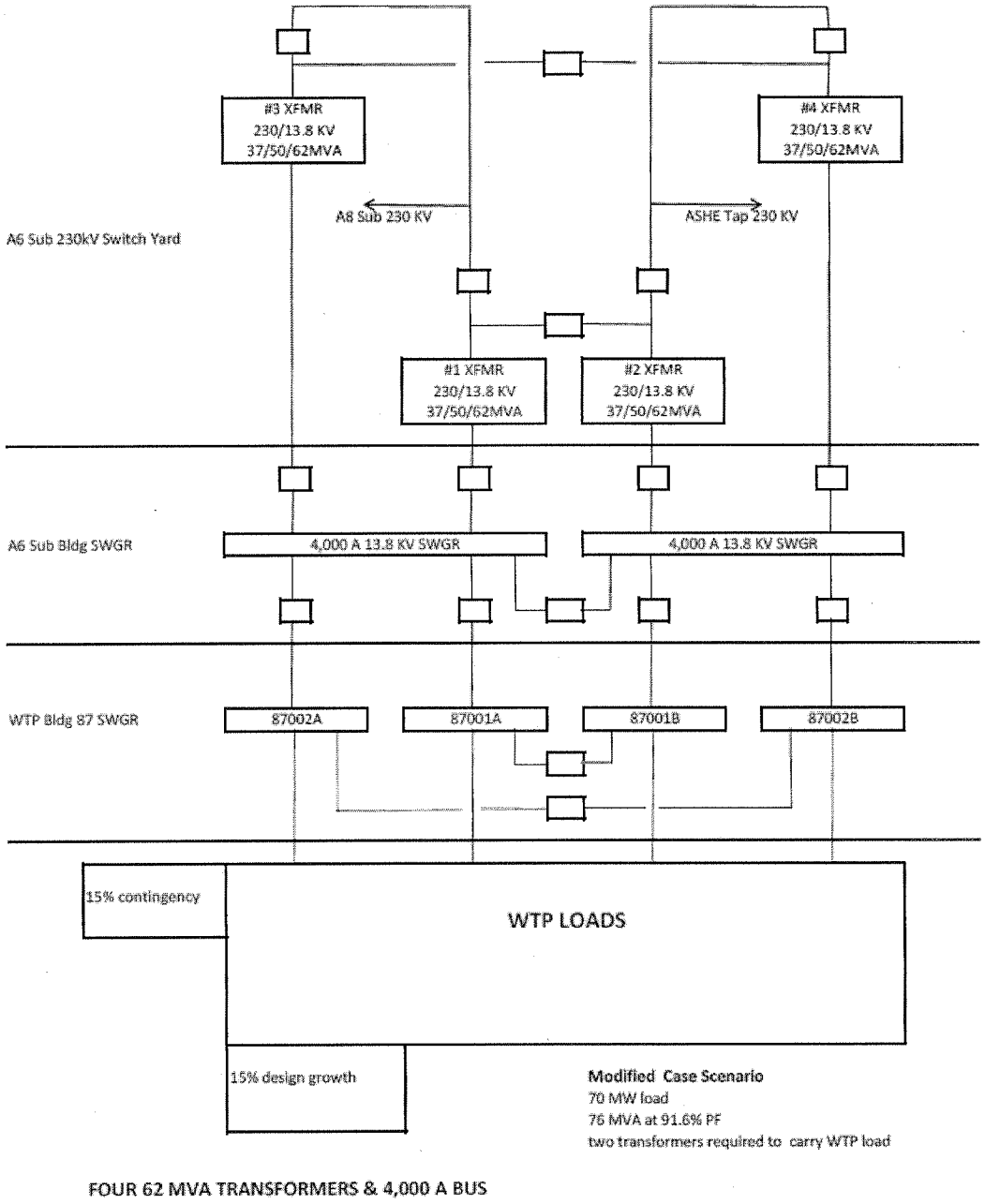
D. Option 3 – Partial Implementation of Future Expansion of A6 Substation

Figure #5 4-37/50/62MVA XFMRs, 2-4kA Swgr, and 1 Swgr Bldg.



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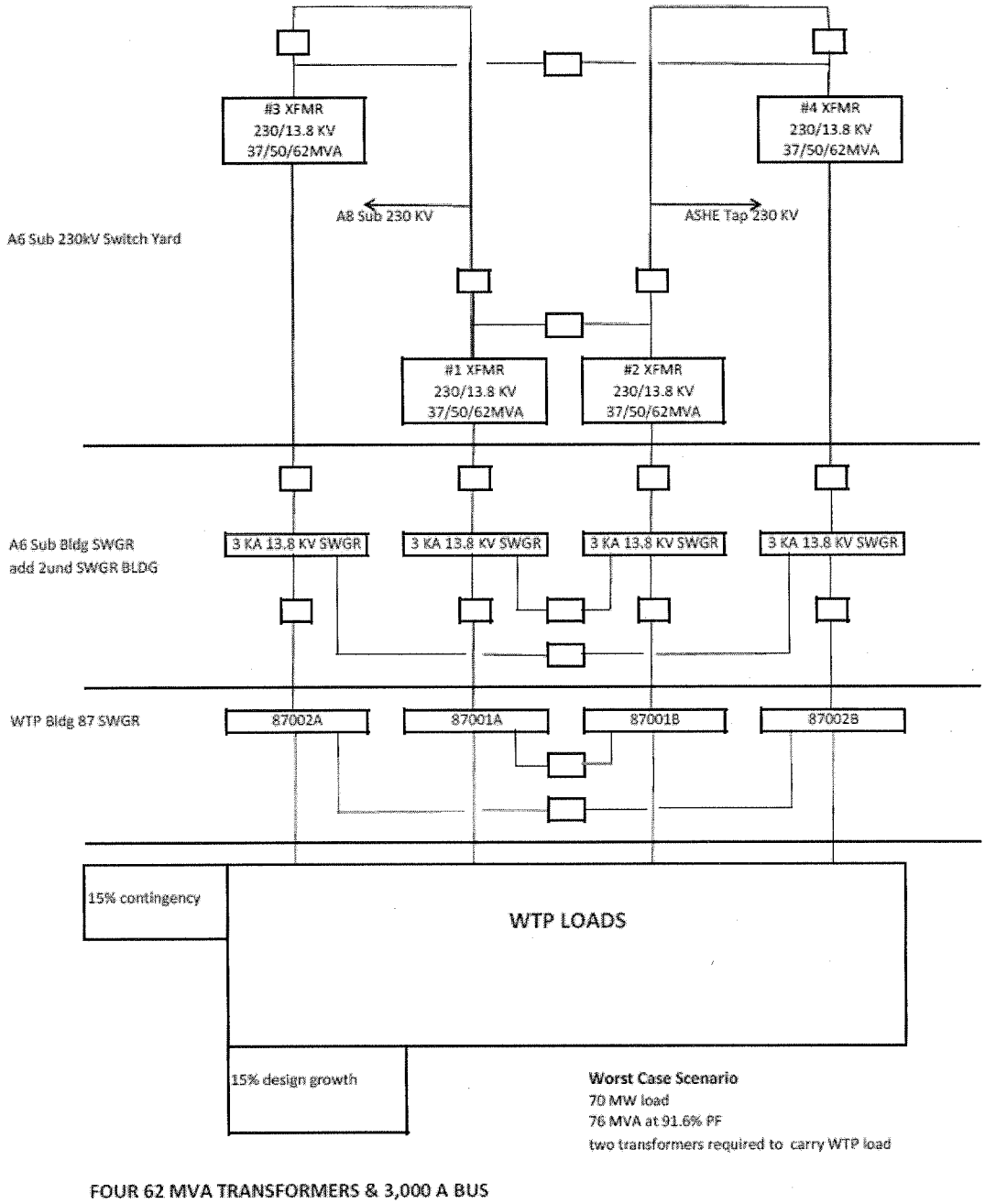
E. Option 4 Implementation of Future Expansion Portion of A6 Substation

Figure #6 4-37/50/62MVA Xfmrs, 4-3kA Swgr, and a 2nd Swgr bldg.



FOUR 62 MVA TRANSFORMERS & 3,000 A BUS

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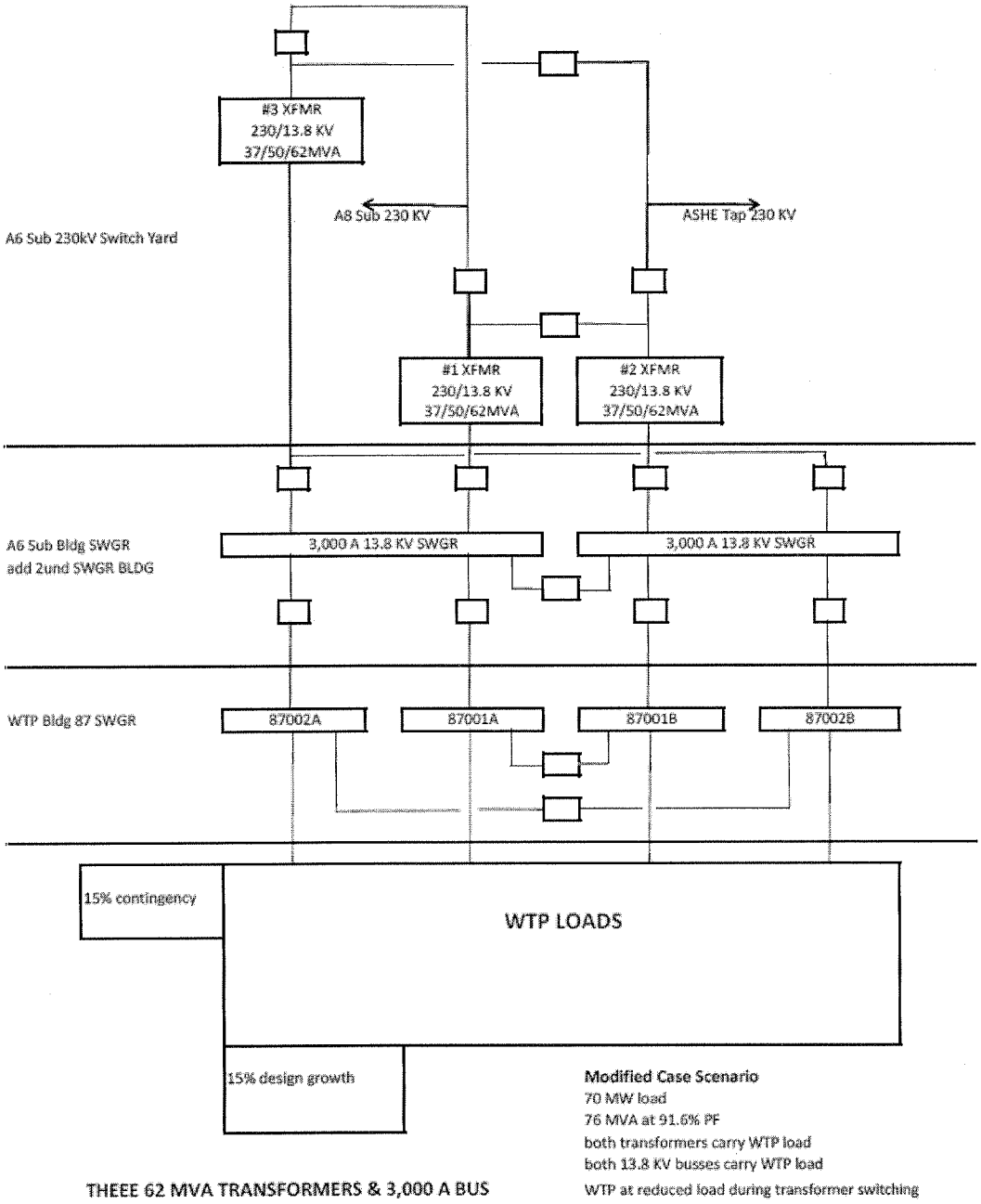
F. Option 5 Swing Bus

Figure #7 Swing Bus



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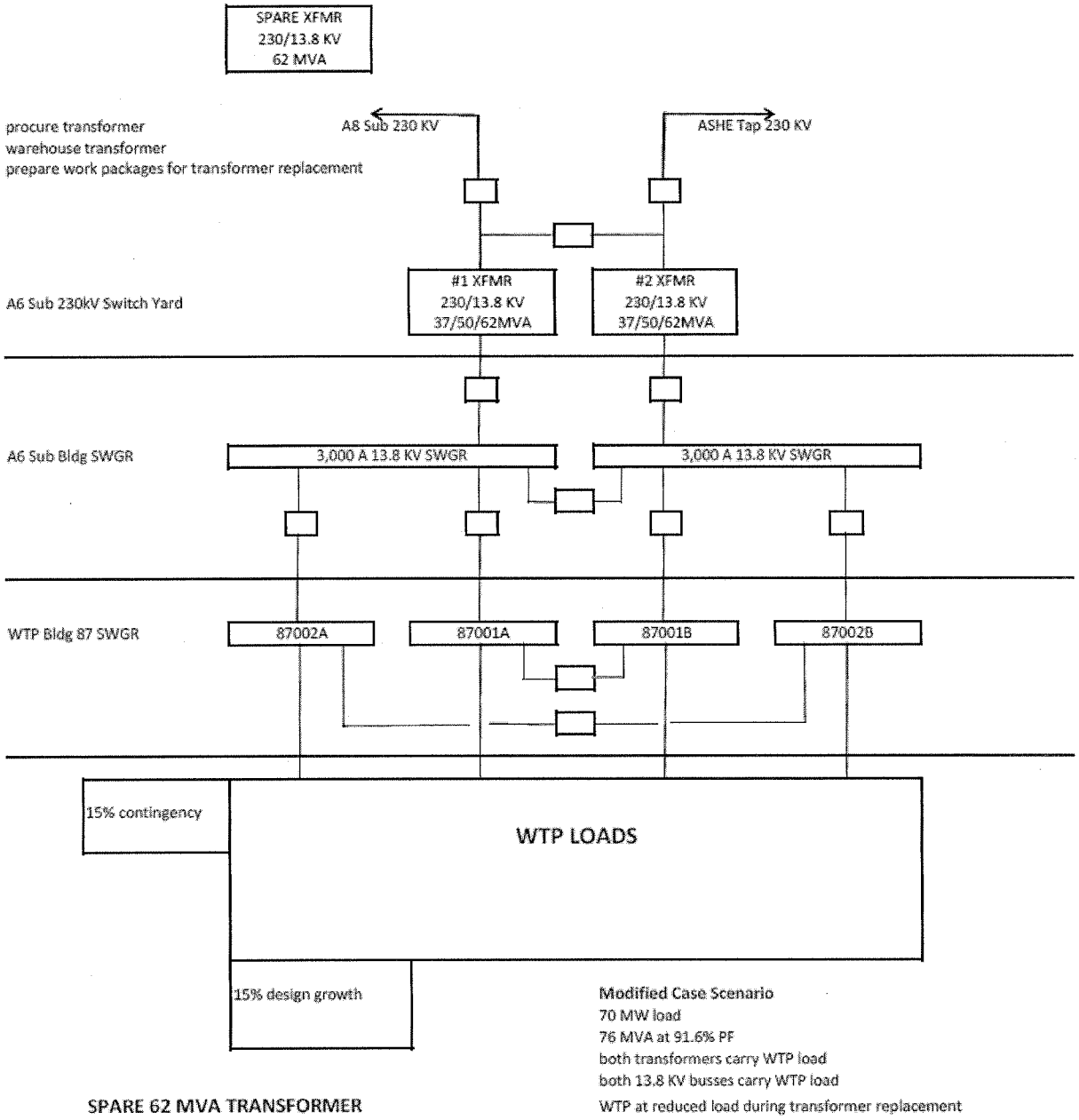
G. Option 6 Warehoused Spare

Figure #8 Warehoused Spare



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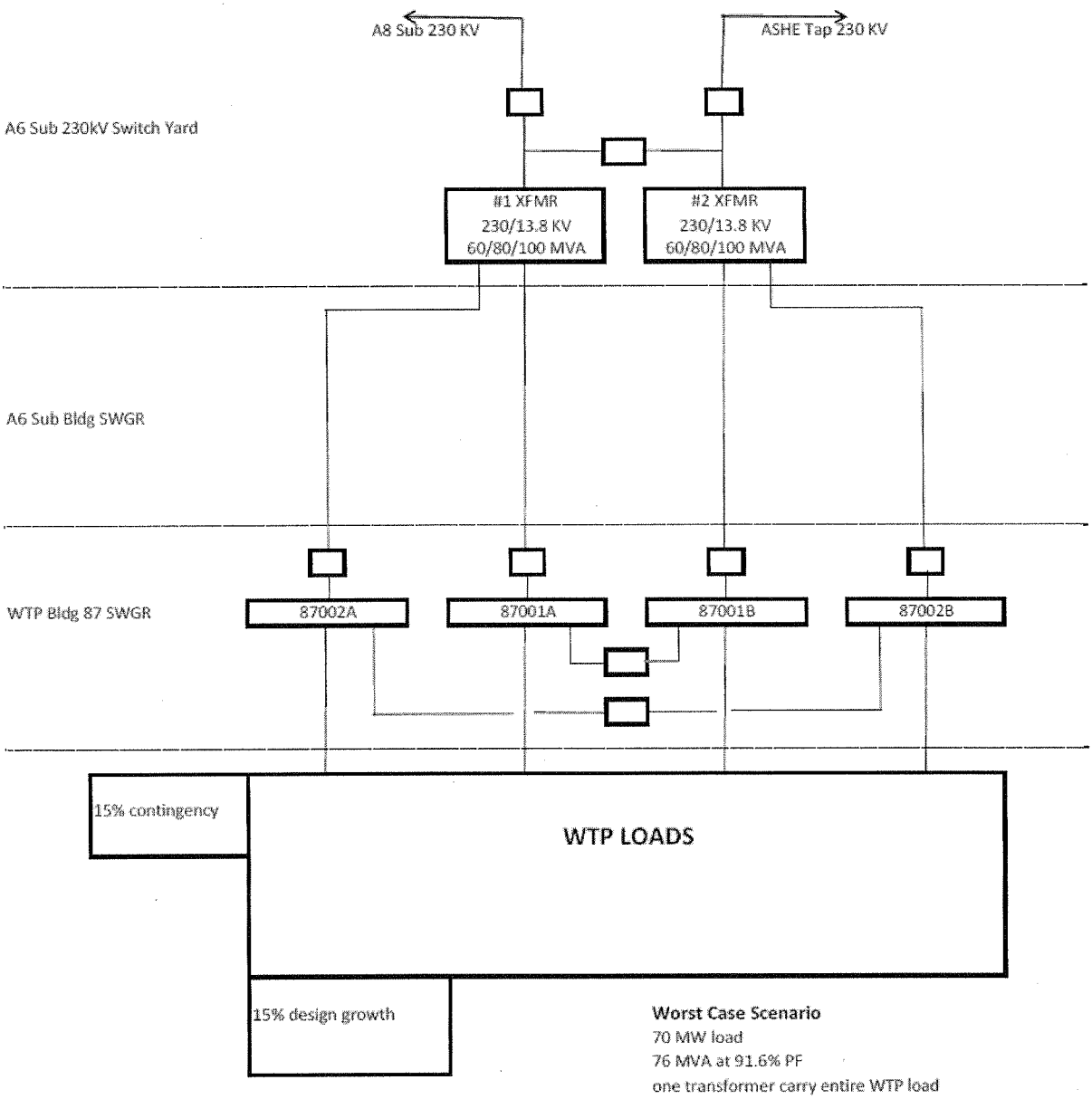
H. Option 7 Eliminate the A6 Switchgear (Direct Power Feed from the A6 Xfmrs to Bldg 87)

This option would require contract changes to the WTP project, the Hanford Electric Utility Operator, and the Tank Farm Operations Contract.

Note: Transformer primary winding rating shown

Figure #9 Two 60/80/100MVA Xfmrs with Direct Feed to B87



TWO 100 MVA TRANSFORMERS & DIRECT FEED TO BLDG 87 SWGR

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This option will require the shared control of the WTP switchgear, with the Hanford 230kV system operator. The 4 main breakers on MVE-SWGR-87001A, 1B, 2A, & 2B would be the point of interface and the utility metering point. Additionally, these switchgears would have to be modified for the relaying necessary to protect the A6 substation transformers.

A contract change would be required for the WTP to implement the necessary modifications to the switchgear in B87 and the WTP contractual documents (ICD-11, PSAR, BOD, etc.) would have to be updated with the change in the point of interface and clarify the power source changes for the B87 Switchgear Building.

With the elimination of the switchgear in the A6 substation, two independent 75kVA, 208/120 V, building service power supplies will need to be provided from B87.

It should also be noted that both the WTP project and the Electrical Utility reiterated these same disadvantages in their review of this study, in opposition to Option 1.

Refer to Option 1 Disadvantages for short circuit capacity concerns regarding transformer impedances necessary to maintain fault currents under 28kA (rms)

I. Option 8 Remove the Requirement of 100% Electrical Load Operations on One Transformer

The idea of this option is to allow the 100% use of both transformers during normal operation. This was an option that was looked during the development of this study at as well, but was disregarded early on due to WTP's implementation of automatic transfer switches in the electrical distribution system. This would create an electrical distribution system that is unstable, i.e., if greater than 62MVA of load was operating and one of the transformers failed, the automatic transfer switches in the WTP electrical distribution system would automatically transfer the opposite bus to the remaining transformer. When the loads on this bus are restarted, depending on the size of the loads being started and the extent of overloading on the remaining transformer, the protective relay system could trip the remaining transformer off line due to over current; there by causing a complete loss of power to the WTP facility.

J. Option 9 Existing A6 Substation Configuration in conjunction with the Fifth Feeder and Power Factor Correction

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This option was reviewed and discussed earlier in the study under PFCS. See section VII.H

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With assumption V.C.3, that the utility metering point is the A6 feeders to WTP, the power factor correction units would have to be physically interfaced with the WTP Building 87 MVE-SWGR-87001A&B and MVE-SWGR-87002A&B. None of the 70MW (76.4MVA) options presented in this study physically affect Building. 87, thus a PFCS could be implemented concurrently.

H. Power Factor Correction and Fifth Feeder

Power Factor Correction could be implemented in conjunction with the Fifth Feeder and using the existing 62MVA transformers. Assuming the Fifth Feeder was operating as an alternate source of power to MVE-SWGR-87003A&B and the PFCS was maintaining a .97 pf, then 60MW (62MVA) of power could be supplied from an existing transformer, with the additional 7MW of power supplied from the A8 substation; for a total of 67MW (73.1MVA) of electrical power.

The total installed cost is estimated on the order of $6.8M. $5.5M estimated by BNI for Option 4 (Ref. #2), plus $1.3M for the power factor correction system (Att. #4)

VIII. ACCEPTANCE CRITERIA

This section pertains only to the evaluation of the various design options to provide 70MW (76.4MVA) of power to the WTP.

A. Functionality

Can the Option being reviewed provide the 70MW (76.4MVA) @ 91.6% lagging power factor (before any power factor correction) of power on a single electrical power source (one transformer/switchgear load group set operating normally) required by DOE in the commission of this study? This is a pass/fail criterion.

B. Reliability

For the purposes of this study, a double ended electrical line-up is considered the most reliable. 2 out of 3 operation is considered the next most reliable electrical line-up. The least reliable electrical line-up is a radial design.

C. Risk

This will be a comparative discussion between the current design requirement, of 100% plant operations with one out of two transformers failed.

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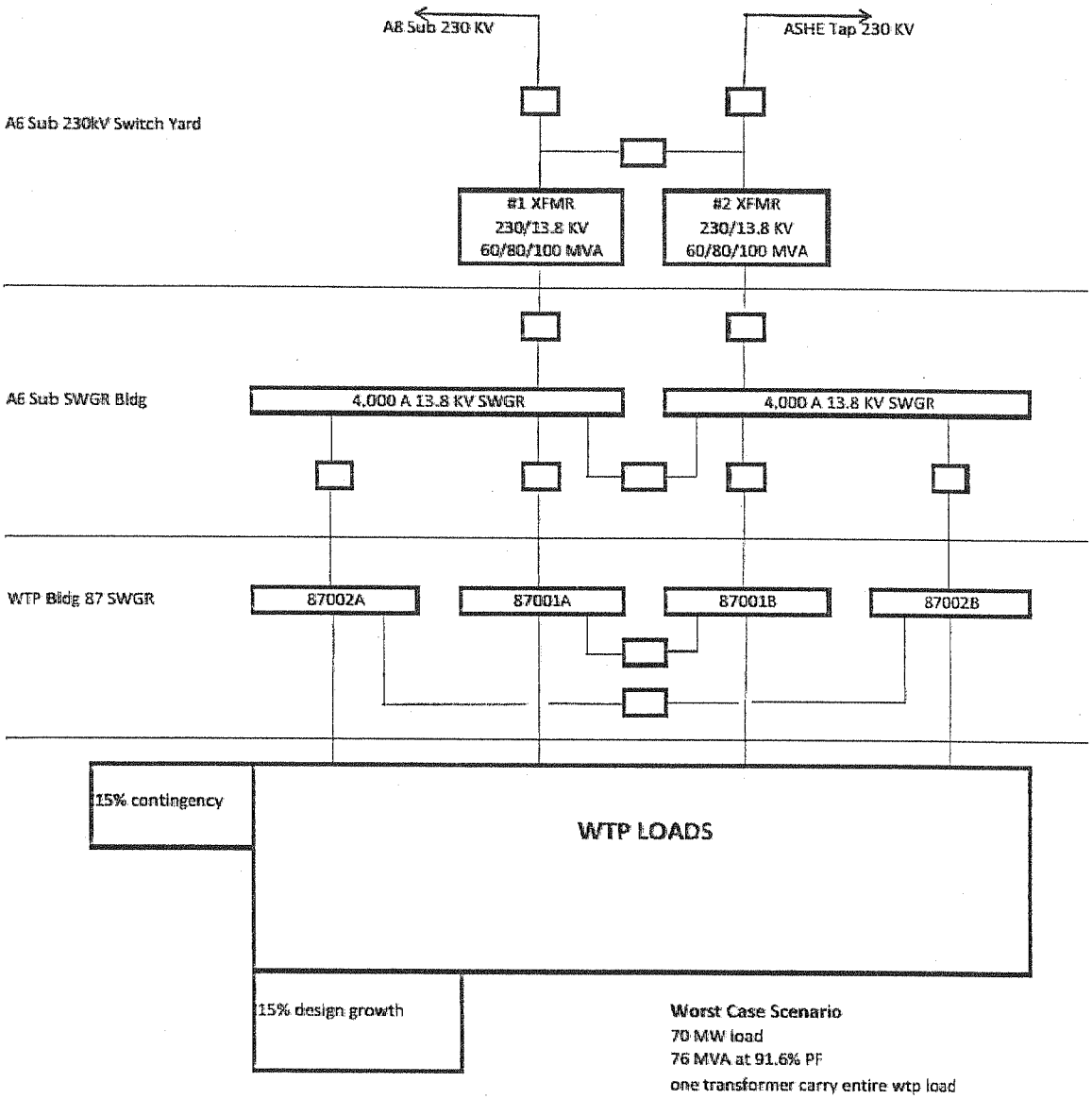
Electrical Utilities' Comments and Proposals

Option 1 – A6 Substation Electrical Equipment Upgrade

60/80/100MVA XFMRs, 2-4kA Swgr, and 1 Swgr Bldg



TWO 100 MVA TRANSFORMERS & 4,000 A BUS

Alternative 1: 2ea 100MVA Xfmrs, 2ea 4kA Sw/g, Control bldg Expansion

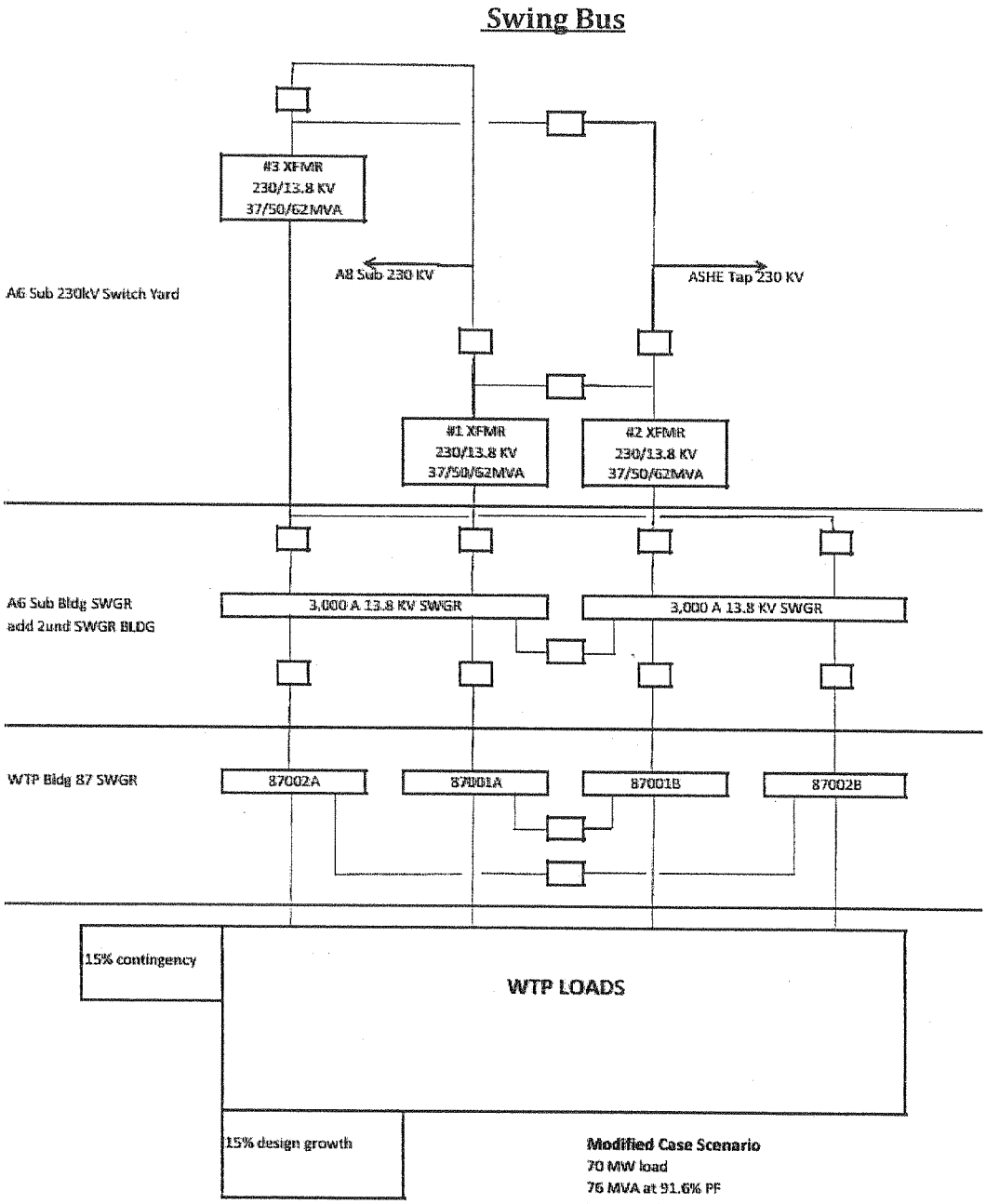
PROs

- Single 100MVA transformer can carry the anticipated load with loss of one stage of cooling fans.
- Operational Interface is clean, follows established guidelines for interface control (TWRS; BPA)
- Separation of ownership of hardware is clean
- Follows established controls of the auxiliary equipment, such as protection schemes and communication systems and interface is well understood and controlled.
- Hanford SCADA system design and communications and operation will remain similar
- Access to EU medium voltage equipment is limit to qualified Utility personnel
- Agrees with current contract re infrastructure services
- Customer relays and protection schemes do not trip open the 230kV loop.
- Additional interface agreements not needed with BPA
- Configuration control maintained by the site utility.
- Continued use of Utility existing lock and tag program.
- Does not require reconnection of WTP loads to new busses if fault duty is not an issue.
- Will not require modification to the 230kV system

CONs

- Non-standard 4000A switchgear- requires fan cooled or gas insulated
- Requires the expansion of the A6 SW/g bldg
- Performance of ops and maint functions may not allow use of established Site Utilities programs and may require training and procedures preparation for 100MVA transformers and 4000A bus.
- A fault and coordination study on the impact of potentially larger fault value, especially when paralleled for switching.
- Transformer pads and oil containment system will have to be modified, rebuilt.
- Larger investment in transformers – may need to add redundant backup relays to protect investment

Option 5 Swing Bus



Modified Case Scenario
70 MW load
76 MVA at 91.6% PF
both transformers carry WTP load
both 13.8 KV busses carry WTP load
WTP at reduced load during transformer switching

THEEE 62 MVA TRANSFORMERS & 3,000 A BUS

Alternative 5: 1ea 62MVA Xfmr, 2ea 13.8kV incomer brkrs, 2ea 230kV GCB, swing bus

PROs

- Two of any three 62 MVA transformer can carry the anticipated load. Loss of cooling fans would allow replacement of bank via switching.
- Maintains use of 3000A switchgear – no increase in bus capacity required.
- Operational Interface is clean, follows established guidelines for interface control (TWRS; BPA)
- Separation of ownership of hardware is clean
- Follows established controls of the auxiliary equipment, such as 13.8kV feeder protection schemes and communication systems and interface is well understood and controlled.
- Hanford SCADA system design and communications and operation will remain similar
- Access to EU medium voltage equipment is limit to qualified Utility personnel
- Agrees with current contract re infrastructure services
- Customer relays and protection schemes do not trip open the 230kV loop.
- Configuration control maintained by the site utility.
- Continued use of Utility existing lock and tag program.
- Does not require reconnection of WTP loads to new busses

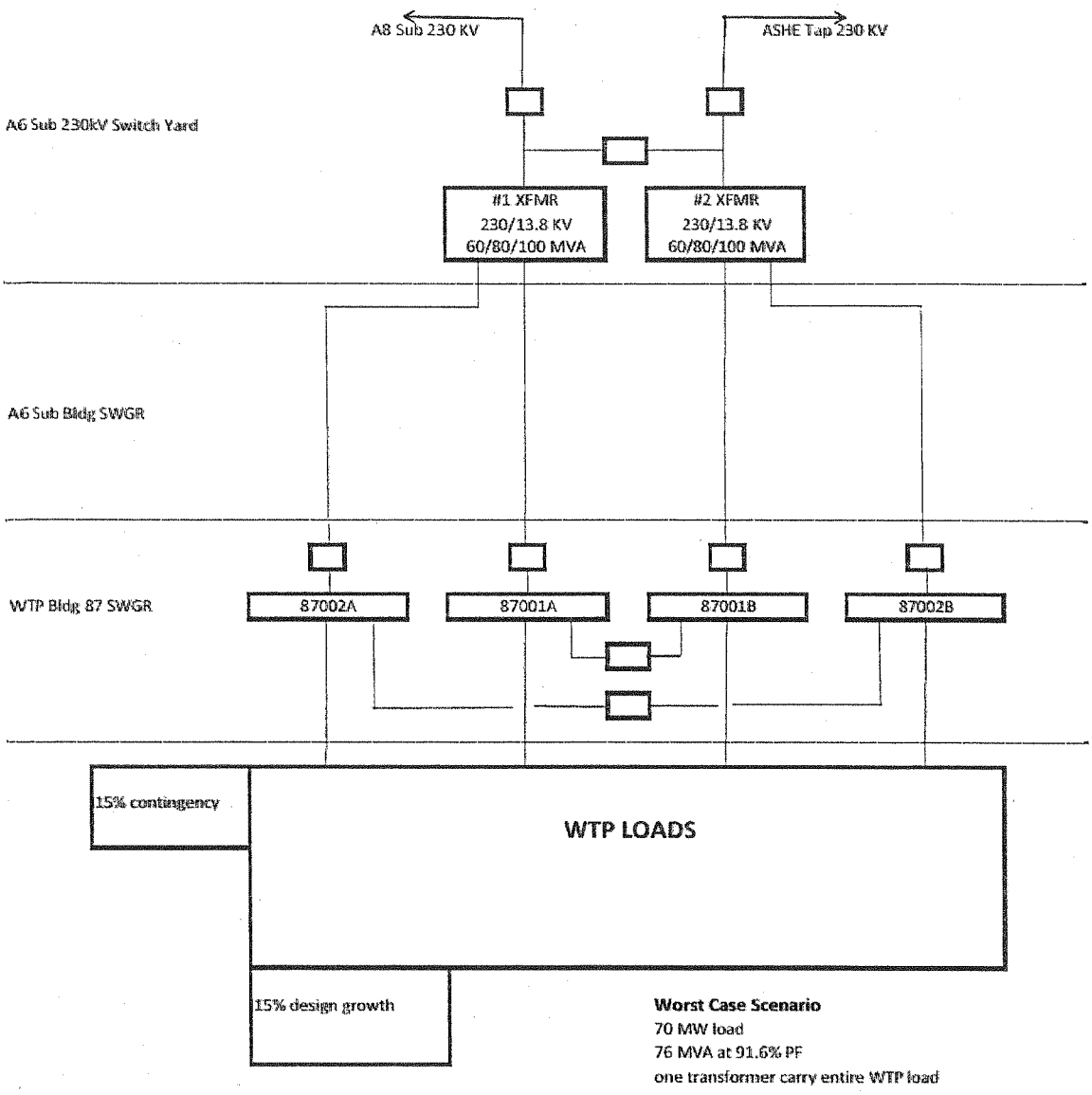
CONs

- May require control bldg expansion for two new incomer breakers.
- Will require protection scheme modifications to the 230kV and 13.8kV busses.
- Different configuration than other EU substations may present different concerns when operating, whether performing routine maintenance or recovering from a disturbance.
- Performance of ops and maint functions may not allow use of established Site Utilities switching conventions and may require procedures preparation for the different possible configurations.
- Coordination and protection analysis on the different possible configurations
- SCADA system points will have to be expanded.
- Additional discussion needed with BPA
- The relay communication for transfer trip scheme will be more complex, will need BPA buy-in
- Availability of RFL equipment

Option 7 Eliminate the A6 Switchgear (Direct Power Feed From the A6 Xfmrs to Bldg 87)

Note: Transformer primary winding rating shown

Two 100MV Xfmrs with Direct Feed to B87



TWO 100 MVA TRANSFORMERS & DIRECT FEED TO BLDG 87 SWGR

6

NOT A VIABLE OTPION TO EU

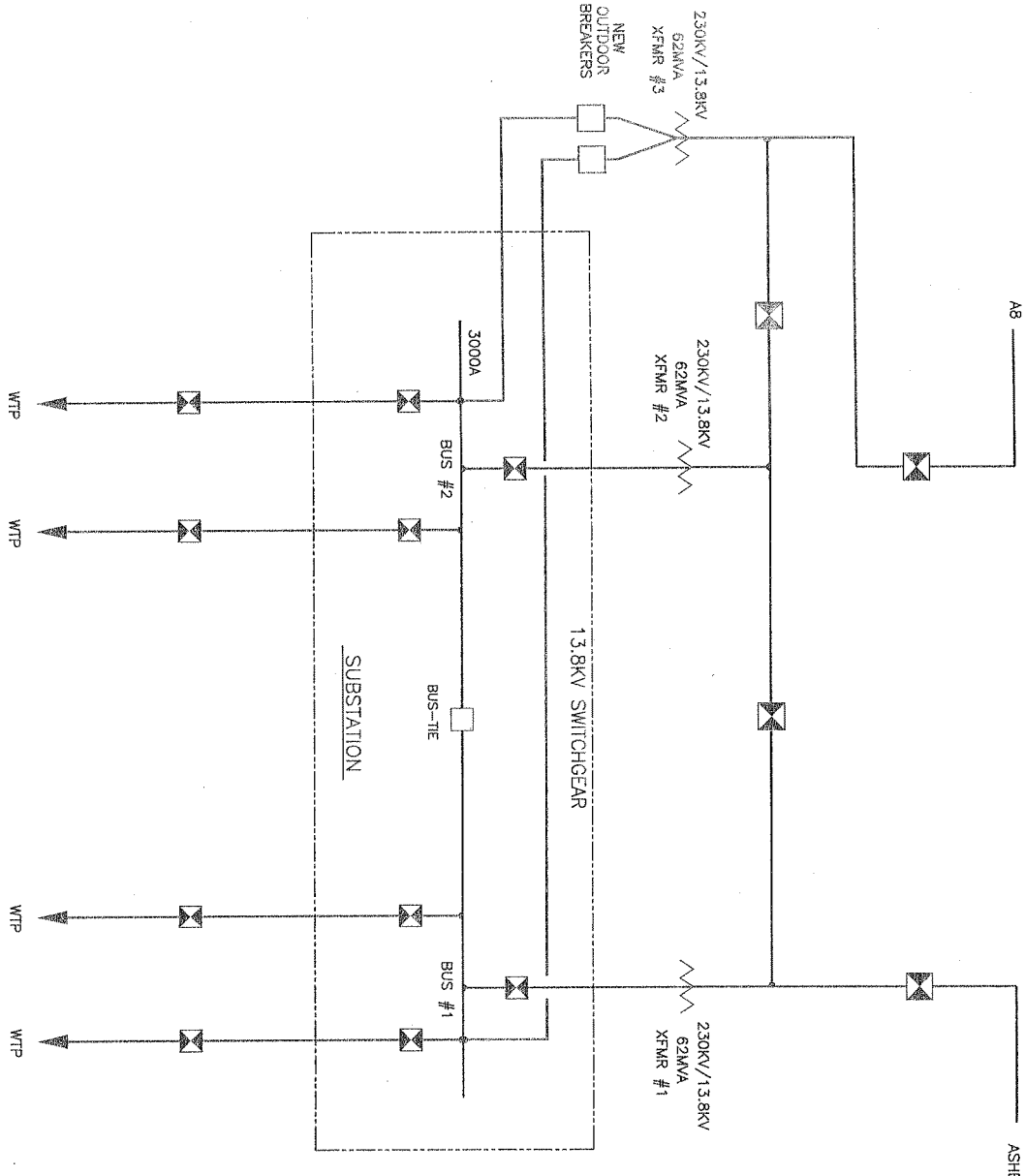
Alternative 7: 2ea 100MVA xfmrs, Direct Feed to Bldg 87)

PROs

- Higher reliability (minimal) due to less equipment that could fail
- Eliminated cost of new switchgear
- Single 100MVA transformer can carry the anticipated load with loss of one stage of cooling

CONs

- Operational Interface is complicated, does not follow established guidelines for interface control (WTP; BPA)
- Separation of ownership of hardware is not clean
- Shared control of the WTP switchgear
- SCADA interface and controls will be difficult, BPA needs to have SCADA controls
- Established controls of the auxiliary equipment, such as protection schemes and communication systems and interface will not be well understood or controlled.
- Required contract change between DOE-RL (MSA) and WTP
- A6 station service will have to come from a tertiary winding from the new 100MVA transformers or be fed from Bldg 87
- Safety practices will not be common to both EU and WTP even though operating and maintain same equipment .
- Duplication of services will be required i.e. maint, ops personnel and qualification of said persons
- Application and use of Utility existing lock and tag program and clearance process will be at odds with the facility programs.
- Loss of configuration control by the site utility.
- Additional interface agreements may be needed with BPA
- Ground grids are not shared between substation and Bldg 87.
- May require fiber optic communications for relays, SCADA
- There still may be a need for CT positions inside the A6 Substation control bldg
- For 100MVA, may need additional differential as a backup. When going the 100MVA size transformer, additional relaying would be wise to protect investment.
- Fault on customer equipment or operation of customer BFR (if equipped) will open the loop.
- Mis-coordination of customer equipment could also open the loop.
- With no EU bus tie, will need to add reverse power relays
- May need communications between A6 and 87Bldg for high speed tripping
- Uncertain how the A6 control bldg will be bypassed
- Metering will be required in Bldg 87
- Bus Tie Control in Bldg 87
- A fault and coordination study on the impact of potentially larger fault value, especially when paralleled for switching at Bldg 87.
- Transformer pads and oil containment system will have to be modified, rebuilt
- Larger investment in transformers – may need to add redundant backup relays to protect investment


ASHE TAP
230KV/13.8KV
62MVA
XFMR #1
AB
230KV/13.8KV
62MVA
XFMR #2
230KV/13.8KV
62MVA
XFMR #3
NEW
OUTDOOR
BREAKERS
13.8KV SWITCHGEAR
BUS #1
BUS-TIE
BUS #2
3000A
SUBSTATION
WTP
WTP
WTP
WTP

EU OPTION #1

Alternative EU 1: 1ea 62 MVA xfmrs, 2ea outdoor 13.8kV brkrs, 1ea 230kV GCB, Swing Bus

PROs

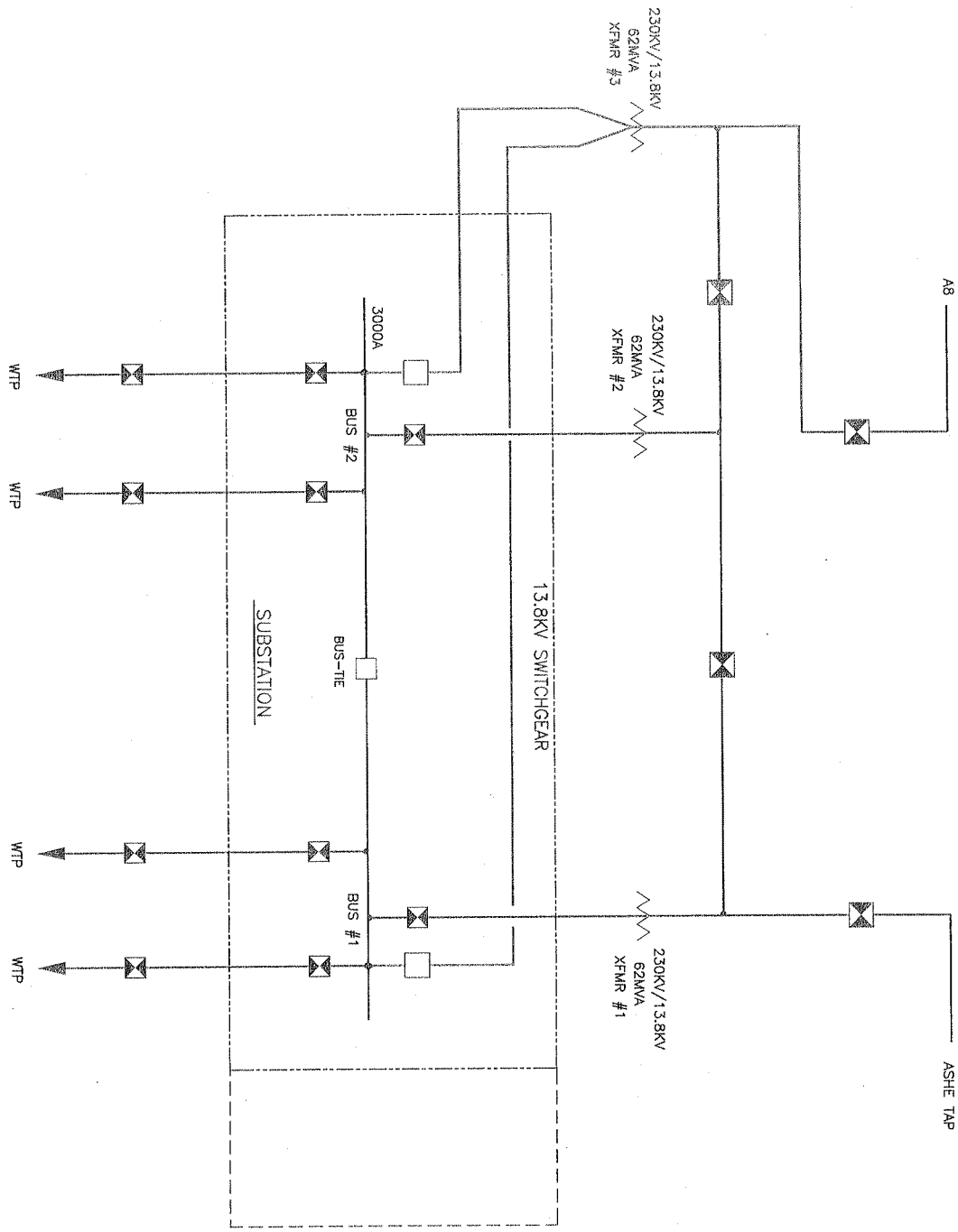
- Two of any three 62 MVA transformer can carry the anticipated load. Loss of cooling fans would allow replacement of bank via switching.
- Maintains use of 3000A switchgear – no increase in bus capacity required
- Operational Interface is clean, follows established guidelines for interface control (TWRS; BPA)
- Separation of ownership of hardware is clean
- Follows established controls of the auxiliary equipment, such as 13.8kV feeder protection schemes and communication systems and interface is well understood and controlled.
- Hanford SCADA system design and communications and operation will remain similar
- Access to EU medium voltage equipment is limit to qualified Utility personnel
- Agrees with current contract re infrastructure services
- Customer relays and protection schemes do not trip open the 230kV loop.
- Configuration control maintained by the site utility.
- Continued use of Utility existing lock and tag program
- Does not require reconnection of WTP loads to new busses
- Expansion of substation control bldg not required.

CONs

- Will require protection scheme modifications to the 230kV and 13.8kV busses.
- SCADA system points will have to be expanded.
- Additional discussion re having two bus ties is needed with BPA
- Coordination and protection analysis on the different possible configurations
- The relay communication for transfer trip scheme will need to be reviewed for impact, will need BPA review

Unknowns

- Cost
- BPA's position on two bus ties
- Coordinating the transfer trip schemes
- Space for additional 230kV and 13.8kV relaying
- Relay types may need to be changed


ASHE TAP
230KV/13.8KV
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230KV/13.8KV
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XFMR #2
230KV/13.8KV
62MVA
XFMR #3
A8
13.8KV SWITCHGEAR
BUS #1
BUS-TIE
BUS #2
3000A
SUBSTATION
WTP
WTP
WTP
WTP

EU OPTION #1A

Alternative EU 1a: 1ea 62 MVA xfmrs, 2ea indoor 13.8kV brkrs, 1ea 230kV GCB, expand control bldg, Swing Bus

PROs

- Two of any three 62 MVA transformer can carry the anticipated load. Loss of cooling fans would allow replacement of bank via switching.
- Maintains use of 3000A switchgear – no increase in bus capacity required
- Operational Interface is clean, follows established guidelines for interface control (TWRS; BPA)
- Separation of ownership of hardware is clean
- Follows established controls of the auxiliary equipment, such as 13.8kV feeder protection schemes and communication systems and interface is well understood and controlled.
- Hanford SCADA system design and communications and operation will remain similar
- Access to EU medium voltage equipment is limit to qualified Utility personnel
- Agrees with current contract re infrastructure services
- Customer relays and protection schemes do not trip open the 230kV loop.
- Configuration control maintained by the site utility.
- Continued use of Utility existing lock and tag program
- Does not require reconnection of WTP loads to new busses

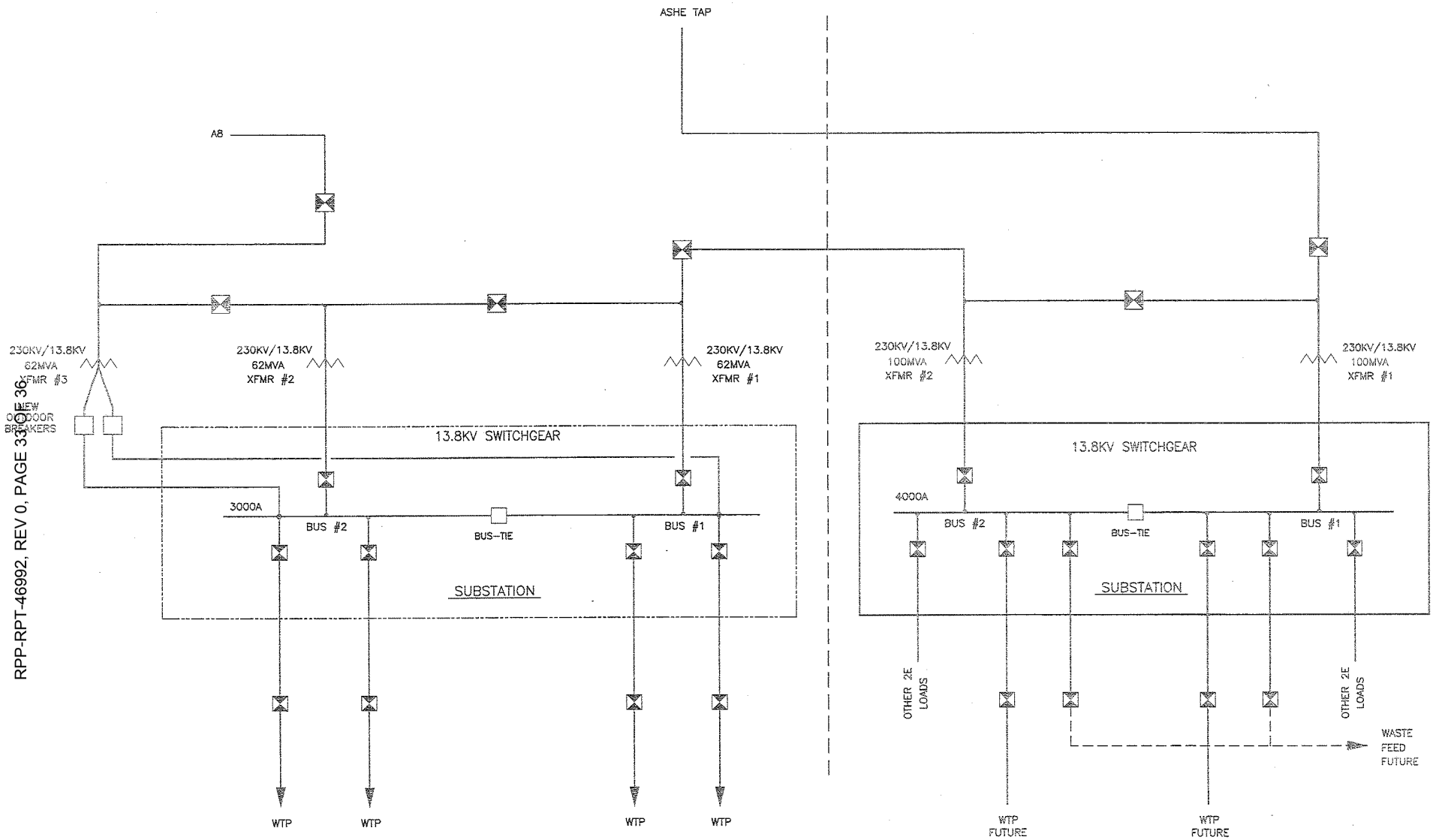
CONs

- Requires control bldg expansion for additional 230kV relay and control panels, and the two new incomer breakers to the sw/g indoors.
- Will require protection scheme modifications to the 230kV and 13.8kV busses.
- SCADA system points will have to be expanded.
- Additional discussion re having two bus ties is needed with BPA
- Coordination and protection analysis on the different possible configurations
- The relay communication for transfer trip scheme will need to be reviewed for impact, will need BPA review

Unknowns

- Cost
- BPA's position on two bus ties
- Coordinating the transfer trip schemes
- Relay types may need to be replaced

EU OPTION #2


ASHE TAP
A8
230KV/13.8KV
62MVA
XFMR #3
NEW
OUTDOOR
BREAKERS
230KV/13.8KV
62MVA
XFMR #2
230KV/13.8KV
62MVA
XFMR #1
13.8KV SWITCHGEAR
3000A
BUS #2
BUS-TIE
BUS #1
SUBSTATION
WTP
WTP
WTP
WTP
230KV/13.8KV
100MVA
XFMR #2
230KV/13.8KV
100MVA
XFMR #1
13.8KV SWITCHGEAR
4000A
BUS #2
BUS-TIE
BUS #1
SUBSTATION
OTHER 2E
LOADS
OTHER 2E
LOADS
WASTE
FEED
FUTURE
WTP
FUTURE
WTP
FUTURE

Alternative EU 2: 1ea 62 MVA xfmrs, 2ea outdoor 13.8kV brkrs, 1ea 230kV GCB, Swing Bus and duplicate substation using 100 MVA transformers

PROs

- Provides additional required capacity for WTP
- Maintains use of 3000A switchgear – no increase in bus capacity Operational Interface is clean, follows established guidelines for interface control (TWRS; BPA)
- Provides power for future tank waste operations loads
- Will not require capacity upgrade to A8 Substation for future 2E tank farm loads
- Separation of ownership of hardware is clean
- Follows established controls of the auxiliary equipment, such as 13.8kV feeder protection schemes and communication systems and interface is well understood and controlled.
- Hanford SCADA system design and communications and operation will remain similar for existing station and will be incorporated into new SCADA for new substation
- Access to EU medium voltage equipment is limited to qualified Utility personnel
- Agrees with current contract re infrastructure services
- Customer relays and protection schemes do not trip open the 230kV loop.
- Configuration control maintained by the site utility.
- Continued use of Utility existing lock and tag program.
- Does not require changes in connection to WTP loads

CONs

- Cost
- Protection issue with two substation so close together
- SCADA system will have to be expanded to add new substation.
- SCADA system points will have to be expanded for existing expansion.
- Additional discussion needed with BPA
- The relay communication for transfer trip scheme will need BPA buy-in
- RFL equipment may not be available
- Non-standard 4000A switchgear

Unknowns

- Cost
- Loads needed for tank farm operations
- Impact of two stations so close together
- Coordinating the transfer trip schemes
- Space for duplicate substation
- Availability of RFL equipment

Alternative Randy's Option: Do nothing Phase 1 - duplicate substation using 100 MVA transformers

PROs

- Except for modification to 230kV bus and bus and transformer differential circuits and redirecting some tip circuits, does not require modification to A6 substation controls, 13.8kV systems, or the control bldg.
- Provides required capacity for WTP (without contingency and load growth) with capability to pick up new WTP processes up to a total of 70MW WTP load. Remaining 90+ MW from substation expansion to be used for waste feed, tank farm operations (and general area feeders if capacity still available).
- New substation expansion will have enough capacity to accommodate waste feed and tank farm loads
- Maintains use of 3000A switchgear inside existing A6 substation – no increase in bus capacity
- Operational Interface is clean, follows established guidelines for interface control (TWRS; BPA)
- Separation of ownership of hardware is clean
- Follows established controls of the auxiliary equipment, such as 13.8kV feeder protection schemes and communication systems and interface is well understood and controlled.
- Hanford SCADA system design and communications and operation will remain similar
- Access to EU medium voltage equipment is limit to qualified Utility personnel
- Agrees with current contract re infrastructure services
- Customer relays and protection schemes do not trip open the 230kV loop.
- Configuration control maintained by the site utility.
- Continued use of Utility existing lock and tag program.
- No cost for Phase 1

CONs

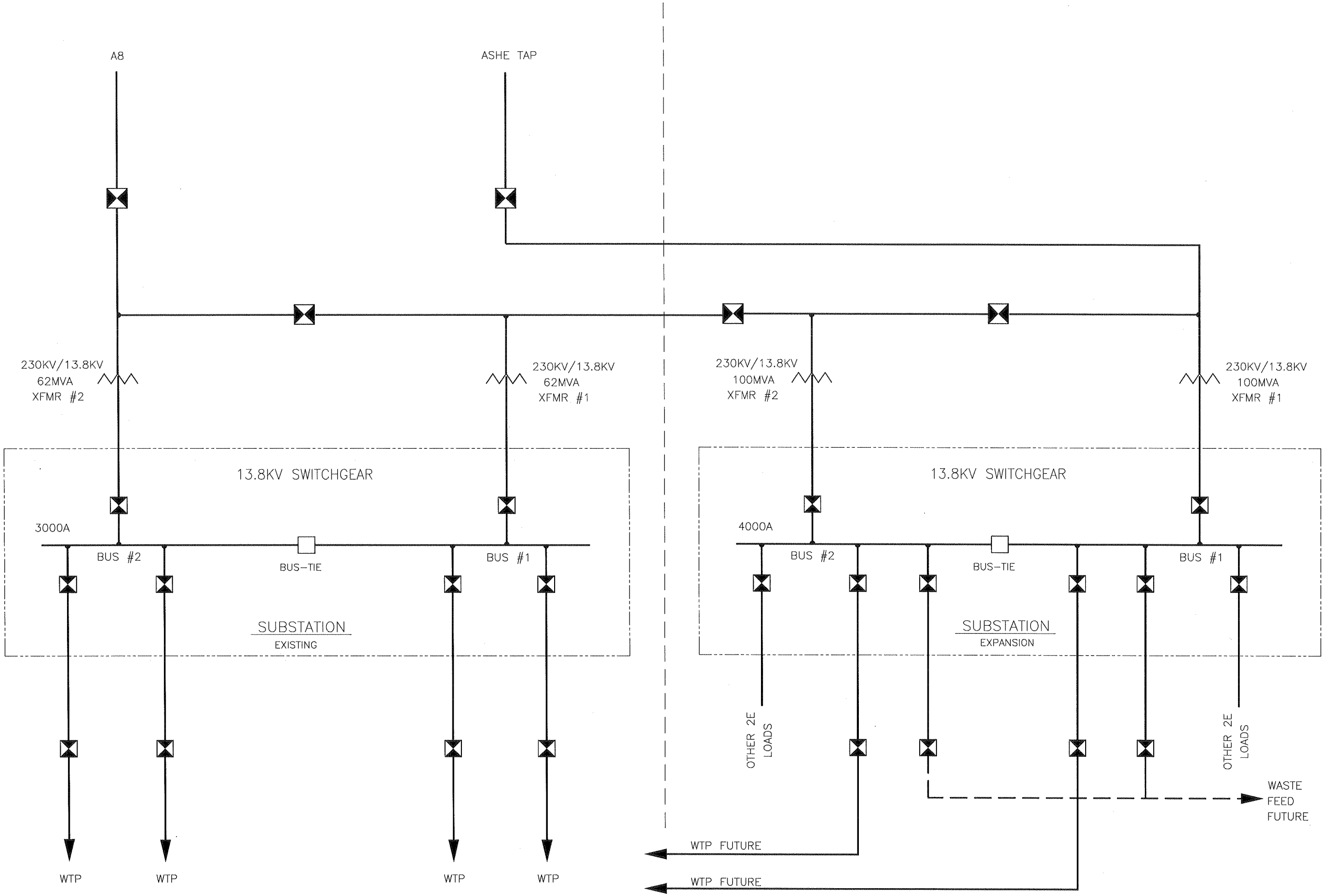
- Will require new connections or changes in connection to WTP loads.
- Additional discussion needed with BPA for any impacts to regional loads and BPA operations

Unknowns

- Cost
- Transformer size needed
- Loads needed for tank farm operations
- Space for duplicate substation

RANDY'S OPTION

(DO NOTHING PHASE 1)



Meeting Minutes

Chairperson: Richard Ziegenbein

Meeting: August 24, 2010, 0700 hours

Location: Building 2101M East Area, Bijou-Cosmos Room

Purpose: Design Review of Revision D of Analysis of Power Delivery to WTP Engineering Study

Prepared by: Richard Ziegenbein

1. **Meeting Attendees**

DOE	MSA	WRPS	BNI
Mazen Al-Wazani	Scott Baker	Jeremy Wilkins	Charles Chan
Randall Krekel	Jane Boyd	Richard Ziegenbein	
	Mike Hache		
	Calvin Dudney		
	Sheree Schweiger		
	Jim Uecker		

2. **Purpose of the Meeting** – Richard stated that the purpose of the meeting is:
   - Discuss review comments on this latest revision D of the study
   - Discuss the incorporation of review comments
   - Discuss the revised project schedule

3. **Discussion of MSA and RL Options** – Richard stated that the primary purpose of the meeting is to discuss technical review comments that pertain to the options that are MSA and RL sponsored. Format comments on the Executive Summary will be addressed separately.

4. **Review Comment and Resolution (RCR)** – Richard stated that review comments will be dispositioned per the WRPS RCR process. Richard will meet with each reviewer to disposition each comment and will ask the reviewer to sign off on the RCR form no later than Friday, August 27, 2010.
   Note: Review comments were received from: MSA on August 19, 2010
   ORP on August 23 and 24, 2010
   MSA on August 24, 2010

5. **Hanford Document Control System** – Richard stated that the URS Study Number 17-05-110-001, Revision 0, will be approved and stamped by Jeremy, a Washington State Professional Engineer. The URS study will be made an attachment to WRPS Report RPP-RPT-46992, Revision 0 and entered into the Hanford Document Control System. The RCRs will also be made attachments to the WRPS report.

6. **WRPS Report RPP-RPT-46992** – Richard stated that the WRPS cover report, RPP-RPT-46992, will be developed to follow the format of the tasking letters received by WRPS from ORP. The Executive Summary and Purpose sections will be ordered to coincide with the specific tasks received by WRPS from ORP. The format of the URS Study Number 17-05-110-001 is based on tasking received by URS from WRPS. The URS report also follows normal engineering study format.

7. **Duration of Outages to WTP** – The group had a general discussion on the duration of power outages to the WTP related to the options presented in the URS study. Jeremy indicated that the rough order of magnitude construction schedules do not address the duration and types of outages to the WTP. It was agreed that this type of detailed outage information could be a valuable option selection criteria to be used later, but was outside the scope of work for the URS study.

8. **National Electrical Safety Code** – The group agreed that the addition of the National Electrical Safety Code, NFPA 70E, Standard for Electrical Safety in the Workplace, was an appropriate addition to the standards listed in Section III of the study.

9. **Authorization Basis Document Revisions** – The group had a general discussion on revisions of the WTP authorization basis documents required by each option. Jeremy indicated that all of the options required revision of some authorization basis documents, but the study does not mention specific documents. The cost of revising the authorization basis documents are not included in the rough order of magnitude construction cost estimates.

10. **WTP Power Monitoring** – Charles indicated that power demand monitoring equipment had been designed for the Building B87 main 13.8 KV switchgear. Power demand will be monitored. As the total demand approaches the maximum 62 MVA capacity of the existing A6 Substation transformers, an alarm will sound in the Pretreatment Facility Control Room. WTP plant operators will be trained to take appropriate actions to preclude overloading a transformer if the WTP load had to carried on only one transformer.

11. **Next Step** – The group discussed actions following the transmittal of the study to ORP. Richard said that the study would be transmitted to ORP no later than September 16, 2010. Mazen said that the next step would require revising ICD-11 to reflect the WTP 70 MW (76.4 MVA) power demand. ICD-11 will used to alert RL of a power deficiency. Randy said that value engineering studies would be required to determine the most appropriate option to pursue.

Attachments: Sign in sheet

August 24, 2010, 8:00 am

2101M, Bijou-Cosmos Rooms

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Krekel, Randall		Randall_N_Krekel@rl.gov	(509)376-4264
Olsen, Gary		Gary_B_Olsen@orp.doe.gov	(509)438-4707
Reed, Garth		Garth_R_Reed@orp.doe.gov	(509)376-2626
Baker, Scott (Eu)		Scott_M_Baker@rl.gov	(509)373-2028
Boyd, Jane A		Jane_A_Boyd@rl.gov	(509)376-1672
Carlson, Cris E		Cris_E_Carlson@rl.gov	(509)373-1560
Dudney, Calvin E		Calvin_E_Dudney@rl.gov	(509)373-6267
Hache, Mike		Joseph_M_Mike_Hache@rl.gov	(509)373-1853

Huard, Catherine R		Catherine_R_Huard@rl.gov	(509)376-2604
Popp, Joseph		Joseph_P_Popp@rl.gov	(509)373-2665
Simmelink, Lee R		Lee_R_Simmelink@rl.gov	(509)373-7753
Smith, Jacob A		Jacob_A_Smith@rl.gov	(509)373-1948
Uecker, Jim		James_E_Jim_Uecker@rl.gov	(509)373-1930
Schweiger, Sheree		sheree_a_schweiger@rl.gov 373-7852	
Chan, Charles		cmchan@bechtel.com	(509)371-3085
Lucke, Gary		gelucke@bechtel.com	(509)371-3093
Garrett, Richard		Richard_L_Garrett@rl.gov	(509)373-3757
Hamm, Earnest		Earnest_R_Hamm@rl.gov	(509)372-0310
Schatz, Zak M		Zakary_M_Schatz@rl.gov	(509)376-6411
Wheeler, Martin		Martin_Wheeler@rl.gov	(509)376-2099
Wilkins, Jeremy		Jeremy_D_Wilkins@rl.gov	(509)551-7917
Ziegenbein, Richard		Richard_S_Ziegenbein@rl.gov	(509)376-0991

APPENDIX G

PROJECT LETTERS

- ORP to WRPS, March 12, 2010, 10-WTP-057/1000326
  - CONTRACT NO. DE-AC27-01 RVI 41 36 – LETTER OF DIRECTION TO PROCEED WITH PERFORMING ANALYSIS AND PREPARE VIABLE OPTIONS FOR INCREASING POWER DELIVERY UP TO MINIMUM OF 70 MEGAWATTS (MW) CAPABILITY UNDER THE WORST CASE SCENARIO TO THE U.S. DEPARTMENT OF ENERGY, OFFICE OF RIVER PROTECTION (ORP), WASTE TREATMENT AND IMMOBILIZATION PLANT (WTP)

- WRPS to ORP, April 22, 2010, WRPS-1000326 R2
  - CONTRACT NUMBER DE-AC27-08RV14800 – WASHINGTON RIVER PROTECTION SOLUTIONS LLC RESPONSE TO LETTER OF DIRECTION TO PROCEED WITH PERFORMING ANALYSIS AND PREPARE VIABLE OPTIONS FOR INCREASING POWER DELIVERY UP TO MINIMUM OF 70 MEGAWATTS CAPABILITY UNDER THE WORST CASE SCENARIO TO THE U.S. DEPARTMENT OF ENERGY, OFFICE OF RIVER PROTECTION, WASTE TREATMENT AND IMMOBILIZATION PLANT

- ORP to WRPS, May 11, 2010, 10-WTP-109/1000648
  - CONTRACT NO. DE-AC27-08RV 14800 – ACCEPTANCE OF THE RESPONSE TO WASHINGTON RIVER PROTECTION SOLUTIONS LLC (WRPS) LETTER OF DIRECTION TO PROCEED WITH PERFORMING ANALYSIS AND PREPARE VIABLE OPTIONS FOR INCREASING POWER DELIVERY UP TO A MINIMUM OF 70 MEGAWATTS (MW)UNDER THE WORST CASE SCENARIO TO U.S DEPARTMENT OF ENERGY, OFFICE OF RIVER PROTECTION (ORP), WASTE TREATMENT AND IMMOBILIZATION PLANT (WTP), WRPS-1000326 R2

- WRPS to ORP, June 30, 2010, WRPS-1000326 R3
  - CONTRACT NUMBER DE-AC27-08RV14800 – WASHINGTON RIVER PROTECTION SOLUTIONS LLC REQUESTS APPROVAL FROM THE U.S. DEPARTMENT OF ENERGY, OFFICE OF RIVER PROTECTION TO ACCEPT THE WASTE TREATMENT AND IMMOBILIZATION PLANT POWER UPGRADE PHASE I REPORT WITH A COMPENSATORY PRELIMINARY ANALYSIS ON IMPACTS BY THE WASTE TREATMENT AND IMMOBILIZATION PLANT LOAD ON THE HANFORD 230 KILOVOLT SYSTEM

- ORP to WRPS, July 20, 2010, 10-WTP-178/1001551
  - CONTRACT NO. DE-AC27-08RV 14800 – RESPONSE TO WASHINGTON RIVER PROTECTION SOLUTIONS LLC REQUEST TO ACCEPT THE WASTE TREATMENT AND IMMOBILIZATION PLANT (WTP) POWER UPGRADE PHASE I REPORT WITH A COMPENSATORY PRELIMINARY ANALYSIS ON IMPACTS BY THE WTP LOAD ON THE HANFORD 230 KILOVOLT SYSTEM

- WRPS to ORP, July 26, 2010, WRPS-1000326 R4
  - CONTRACT NUMBER DE-AC27-08RV14800 – WASHINGTON RIVER PROTECTION SOLUTIONS LLC REQUESTS APPROVAL FROM THE U.S. DEPARTMENT OF ENERGY, OFFICE OF RIVER PROTECTION TO ACCEPT THE WASTE TREATMENT AND IMMOBILIZATION PLANT POWER UPGRADE REPORT ON SEPTEMBER 16, 2010

- ORP to WRPS, August 12, 2010, 10-WTP-196/1001829
  - CONTRACT NO. DE-AC27-08RV 14800 – RESPONSE TO WASHINGTON RIVER PROTECTION SOLUTIONS LLC REQUEST APPROVAL FROM THE U.S. DEPARTMENT OF ENERGY, OFFICE OF RIVER PROTECTION (ORP) TO ACCEPT THE WASTE TREATMENT AND IMMOBILIZATION PLANT (WTP) POWER UPGRADE REPORT ON SEPTEMBER 16, 2010