Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

SECURITY AND CONTINUITY OF OPERATIONS

December 13, 2013

In reply refer to: NN-1

Paul Koberstein
Cascadia Times
4037 N. Overlook Terrace
Portland, OR 97227

FOIA #BPA-2013-01716-F

Dear Mr. Koberstein:

This is a partial response to your request for records that you made to the Bonneville Power Administration (BPA) under the Freedom of Information Act (FOIA), 5 U.S.C. 552.

You requested:
"all documents related to the Columbia Generating Station condenser that are dated 2000 to 2013."

Response:
BPA is releasing the enclosed documents with certain information withheld pursuant to Exemption 5 and Exemption 6 of the FOIA.

BPA asserts Exemption 6 for information which could reasonably be expected to constitute an unwarranted invasion of personal privacy if disclosed. The withheld information consists of the personal names and contact information (email and cell phone numbers) of individuals. There is no public interest in the disclosure of this information because it does not shed any light on how BPA has performed its statutory duties. Therefore, the individual privacy interest outweighs the public interest in the disclosure of this information.

Exemption 5 protects from mandatory disclosure "inter-agency or intra-agency memorandums or letters that would not be available by law to a party other than an agency in litigation with the agency . . ." Exemption 5 incorporates the deliberative process privilege which protects advice, recommendations, and opinions that are part of the process by which agency decisions and policies are formulated.

One released email, dated January 10, 2007, is missing an attachment; an Excel spreadsheet with monthly average (flat) prices for calendar years 2007-2015. We are attempting to locate it.
The remaining responsive documents are undergoing review for withholding under Exemption 3, 4, & 5 of the FOIA and will be released when those reviews are complete.

The statute requires that requests be acted on “promptly,” and “every effort” be made to respond within 20 working days. However, BPA has determined that your request for information is a “complex” request. A complex request is defined in the FOIA as “unusual circumstances” exist. Unusual circumstances are defined as searching inactive records; where a “voluminous” amount of data is involved; where information about other individuals has to be redacted; or where BPA has to consult with another agency which has a substantial interest in the response.

As such, we will be unable to meet the 20 work-day time frame set in the statute. We are processing complex requests in a “first in, first out” basis and will keep you apprised of our progress. Our goal date for completing your request is January 31, 2014.

I appreciate the opportunity to assist you. Please contact Kim Winn, FOIA/Privacy Act Specialist at 503-230-7305 with any questions about this letter.

Sincerely,

/s/Christina J. Munro
Christina J. Munro
Freedom of Information/Privacy Act Officer

Enclosure: Responsive documents

Progress Report on ACPRT Review
CGS Condenser Replacement

The Agency Capital Project Review Team (ACPRT) is reviewing the business value of Energy Northwest (ENW)'s condenser replacement project for BPA. The review is focused on the financial implications of four alternatives that were considered in a Huron Consulting Group study commissioned last winter by ENW:

1. Titanium modular replacement installed in 2011;
2. Titanium modular replacement in 2015;
3. Titanium retube with new tubesheets in 2011; and
4. Titanium retube with new tubesheets in 2015.

The Huron Study concluded that the Titanium modular replacement – 2011 alternative was preferable because it offered greater technical and operational benefits than the titanium retube alternative and because it was financially advantageous to proceed sooner rather than later. ENW included the modular replacement – 2011 alternative in its FY 2009 budget, which the ENW Board approved and BPA non-disapproved in late spring 2008. This alternative is also reflected in the spending levels that BPA proposed in the Integrated Program Review.

The Huron Study process was largely closed to BPA and other stakeholder review until it was completed in February 2008. The Study's analytical approach, assumptions, and results were documented, however, and the Study serves as the primary source of financial data for the ACPRT's review. Huron evaluated the financial costs and benefits of the alternatives using the same life cycle costing/net present value method that Bonneville now uses to evaluate other capital projects. At the Administrator's direction, the review is being conducted with currently available materials; no request has been made for supplemental information from ENW or Huron, and no business case was requested or submitted. PGC is a full partner in the review.

We anticipate completing the review by the first week in August. Power Services will be briefed and comments considered before findings are advanced to the CAB. The ACPRT's report will cover the (1) financial and risk implications of the project alternatives and (2) a high-level assessment of ENW's capital decision practices with regards to BPA's asset strategy and standards for capital project valuation.

The ACPRT has replicated the financial analytics performed by Huron, and issues have been found that affect the calculation of net present values for the four alternatives. For example:

- The discount rate that Huron used to determine the net present value of the alternatives was 6.5 percent (reflecting ENW's weighted average cost of capital), rather than the 13 percent risk-adjusted discount rate that BPA has established for Federal hydro and other capital projects in Power Services.
- Incremental cash flows for each alternative were not developed by comparison to a reference, or "no action" case. All other things equal, the net effect of this is that long-term benefits were overstated
- Replacement power costs (due to lost generation) and savings were not fully accounted for, nor was replacement power cost uncertainty.

We are re-running the analytics now, and offer no findings or conclusions at this point.

DRAFT

8/11/08

has AJR Comments

ACPRT Review

CGS Condenser Replacement Project

Scope

Methodology

Results

Scope and purpose

Scope of review

- **The Huron Study assessed the financial implications of two, operationally viable project alternatives under two installation timeframes**
  1. Titanium modular replacement installed in 2011
  2. Titanium modular replacement installed in 2015
  3. Titanium retube with new tubesheets in 2011
  4. Titanium retube with new tubesheets in 2015

- **The Huron Study concluded that alternative 1 – Titanium modular replacement installed in 2011 – was preferable**
  - Financially most advantageous

Huron spreadsheet

	Net present values (Expected values - $000) 2011	2015
Modular titanium replacement	**5,535**	**(668)**
Titanium retube with new tubesheets	**(103,803)**	**(90,873)**

* Huron's presentation, "Main Condenser Business Case", shows $18,652 for modular titnium replacment and $(90,714) for titanium retube. These amounts are not substantiated by the cdocumentation available to the ACPRTS, however.

  - Modular replacement otherwise preferable to re-tubing alternative (less contamination risk, less risk of damage to tubes during installation (extends length of outage), improved thermal performance)

Scope of review

was non disapproved

FY09 too

- **ENW approved the project largely on the strength of Huron's recommendation**
  - BPA non-disapproved FY 2009 budget (FY 2009 funding)
  - Procurement contract non-disapproval will be due in October/November
- **The ACPRT's "due diligence" review is focused on the methodology and assumptions Huron used to assess the financial implications of the four alternatives**
- **At the Administrator's direction, the ACPRT's review relies on existing, currently available materials and PGC expertise only**
- **No request has been made for supplemental information from ENW or Huron, and no standardized business case has been submitted**

Scope of review *(3)*

- **Unlike other project reviews, the ACPRT is making no recommendation on a project alternative**
  - A full business case and access to Huron and to ENW SMEs would be needed first
  - Project execution risks are very large -- and access to a project plan to test risk management planning and controls would also be needed

- **Rather, we provide our critique of the Huron Study and our assessment of the alternatives' financial implications**

Methodology

Huron Study's methodology

- **The Huron Study employed net present value as the financial metric that determines the alternative that is financially most advantageous**
  - Cash flows over the investment's expected life span were developed for each alternative
  - The cash flows for the alternatives were then discounted and compared
- **The Study then recommended the alternative shown to have the most favorable NPV**
- **In concept, Huron's approach – determine net present values based on life cycle cost and benefit cash flows – comports with BPA's approach to capital project valuation**

Huron Study's methodology (2)

- **The Huron Study process was largely closed to BPA and other stakeholder review and comment until it was completed in February 2008**

- **That said, the Study's analytical approach, assumptions, and results are documented**
  - BPA staff gained access to the spreadsheets Huron used to determine cashflows and NPVs
  - For many data inputs, we know what was assumed but often not why

ACPRT's approach

- **ACPRT's review is limited to the titanium modular replacement and titanium retube alternatives covered by the Huron Study**
  - We accept ENW's judgment that other alternatives – e.g., copper retube using existing tubesheets and stainless steel modular replacement -- are unacceptable operationally/technically
- **ACPRT has created an NPV-based model that starts with Huron's spreadsheets**
  - The model allows us to make corrections, updates and enhancements to Huron's analysis

The ACPRT employs the same financial metric, the same life-cycle cash flow approach, and essentially the same source data as Huron

ACPRT's approach (2)

- **No changes have been made to Huron's project cost data**
  - In other words, no change to procurement, installation, testing and decon/disposal data for the modular replacement and retube alternatives
  - Huron Study identifies ENW and Industry SME sources
  - No access to these sources, therefore no ability to test project cost and cost uncertainty data
- **Updates and enhancements have been made to lost revenue/replacement power cost data and modeling**
- **Several methodological and other analytical fixes have also been made**

ACPRT changes to Huron's modeling

Significant issue, not the only only one

- **Incremental cash flows in the Huron Study were not developed by comparison to a base case**
  - For purposes of determining net present values, cash flows must be incremental cashflows
  - For this project, incremental cash flows should be determined by reference to a "run to failure" base case
  - The Huron study did not apply a base case consistently – the modeling effectively assumed that the current condenser never fails, meaning that . . .
    - There are benefits shown for an undue length of time
    - There are no costs to replace it when it does eventually fail
  - All other things equal, the net effect of this error is that the long-term benefits of the alternatives are overstated
  - ACPRT's base case assumes that the current condenser will be replaced or re-tubed in 2018 (estimated end of condenser's useful life – PGC)
    - Sensitivity is also run for replacement/retubing in 2020

2018

I'll run the model with just this change isolated

ACPRT changes to Huron's modeling (2)

- **Lost revenue/replacement power cost estimates did not fully capture market price and outage duration uncertainties**
  - ACPRT is now using an updated, probabilistic forecast of market prices
  - A "worst case" outage duration case has now been added (incremental 30, 40, and 62 days)
- **A couple of cost factors were improperly treated**
  - For example, eddy current testing costs were calculated on a gross not incremental basis, and they were improperly treated in the cashflows
- **Horizon of cashflows extends beyond estimated useful service life**
  - Horizon of cash flows reduced to 20 years, with an estimate of the condenser's residual value inserted at year 20
    - Not a flaw in Huron's Study, but this change comports with BPA's treatment of other capital projects
    - ACPRT determined the residual value as net book value in year 20 — undepreciated life

assumed 40 years useful life

$1M impact.

about 9% is where the crossover point for 2011 to 2015

- **Discount rate was not risk-adjusted and inconsistent with BPA's standard**
  - Huron Study: 6.5 percent (reflecting ENW's weighted average cost of capital)
  - ACPRT review: 13.0 percent (risk-adjusted discount rate for Federal hydro and all other capital projects in Power Services)

pretty substantial change

makes a later installation a better deal

– Same rate for Fed. Hydro projects

risk adjusted

weighted average cost of capital

David B

mike: We're prepared to dig in on this one. It's what been decided by BPA.

ACPRT modeling results

Huron using 3% escalation for all costs. ACPRT tried to split up components and have ability to use different escalation factors — but in the end they used 3½%

H's not validated for Aurora yet. (latest H's) from last Friday.

Expected value costs

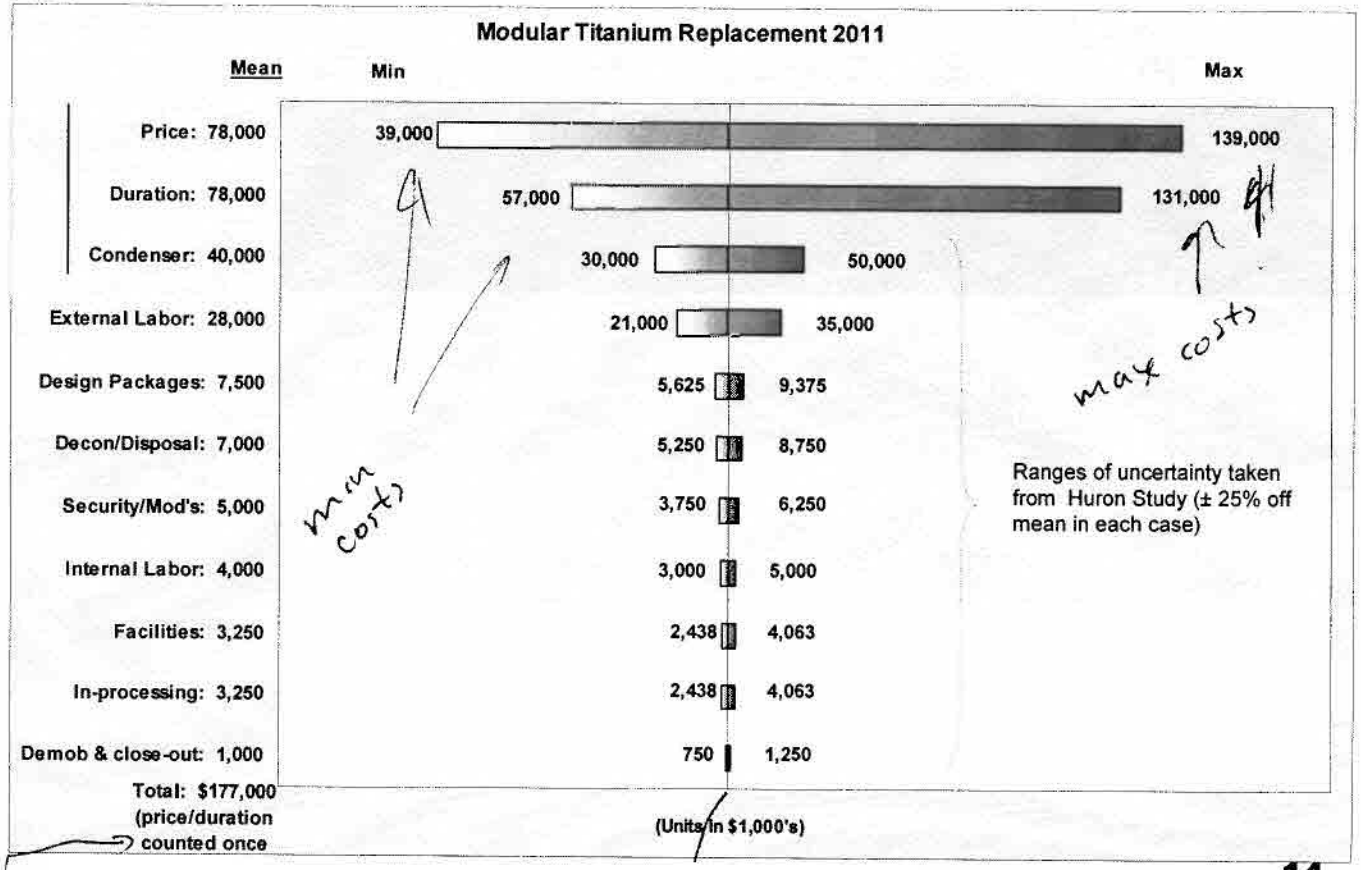
(Nominal totals thousands of dollars)

	Installation Year 2011			2015			2018	
	Huron Study	ACPRT review		Huron Study	ACPRT review		Huron Study	ACPRT review
Titanium modular replacement								
Project Costs	106,370	98,958	-7412	96,468	115,437	18969	n/a	127,987
Lost revenue/replacement power costs during installation	71,756	78,813	7,057	80,841	80,841	0	n/a	91,753
	178,126	177,771	(355)	177,309	196,278	18,969		219,740
Net present value	5,535	(31,014)		(90,873)	(8,946)			
Retube - titanium sheets								
Project Costs	87,095	86,915	(180)	98,781	101,703	2,922	n/a	118,406
Lost revenue/replacement power costs during installation	71,073	78,813	7,740	80,071	86,143	6,072	n/a	91,753
	158,168	165,728	7,560	178,852	187,846	8,994		210,159
Net present value	(103,803)	(38,862)		(90,873)	(11,995)		n/a	n/a

Market price and outage duration are the greatest risks

Titanium and other procurement cost risks are also big

Tornado charts shows range of uncertainty



only one is taken & counted, of the price, or duration

min line or value

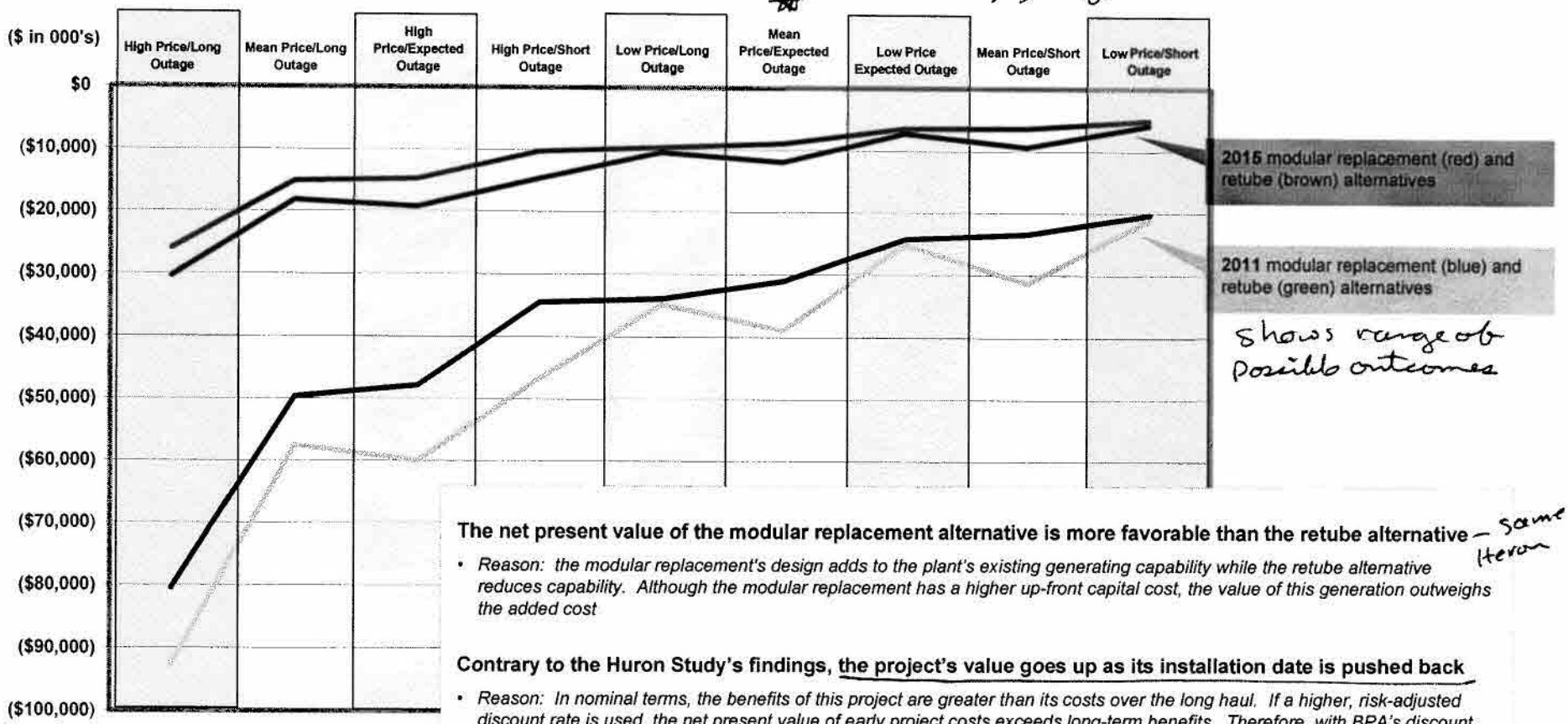
mean line

max line

doesn't capture uncertainty around project costs only used expected value

3.5% Project Cost Escalation

NPV as a Function of Market Price and Outage Duration Variability



shows range of possible outcomes

The net present value of the modular replacement alternative is more favorable than the retube alternative – same as Huron

- *Reason: the modular replacement's design adds to the plant's existing generating capability while the retube alternative reduces capability. Although the modular replacement has a higher up-front capital cost, the value of this generation outweighs the added cost*

Contrary to the Huron Study's findings, the project's value goes up as its installation date is pushed back

- *Reason: In nominal terms, the benefits of this project are greater than its costs over the long haul. If a higher, risk-adjusted discount rate is used, the net present value of early project costs exceeds long-term benefits. Therefore, with BPA's discount rate (13.0% Vs Huron Study's 6.5%), a later installation date is more economic*

NPV variability is driven largely by the length of outage and prevailing market prices

- *Lost revenue/replacement power costs can more than double the NPV cost of the current 2011 installation plan*
- *Titanium price risk and other project risks are not reflected*

2018 replacement would be the best if that case were run.

extension would begin in July.

Managing cost risks

Start April 2
+ 35 days regular outage
+ incremental outage days of 40.

guestimate.

Outage duration risks

- **Expected increment duration of planned outage is 40 days**
  - Range of uncertainty is 31 to 61 days, with lost revenue/net replacement costs ranging from $ to $
- **What could go wrong?**
  - (to be added)

installation problem
operational risk
failure to execute on the plan.
manufacturing error (unknown, unexpected)

- **What the objectives be to manage these risks?**
  - (to be added)

one planned.

- **What steps ~~should be taken~~?**
  - (to be added)

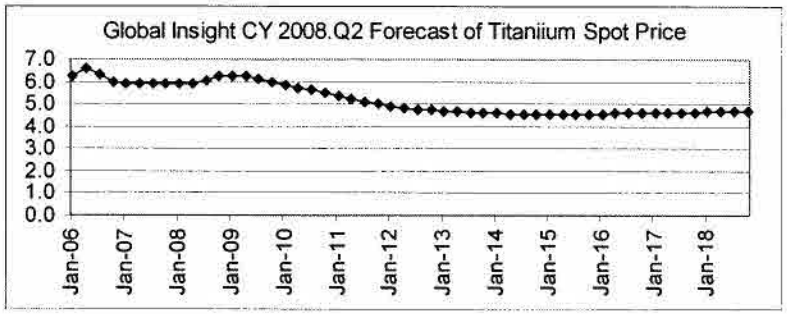
Consultants -
benchmarking

Managing cost risks (2)

Procurement cost risks

- **Procurement costs are estimated in the Huron Study at $40 million, with cost uncertainty ranging from $30 million to $50 million**
  - Vendor bids are due in October

- **Titanium prices are the key uncertainty -- prices have been volatile and escalating in recent years. Forecast is that titanium prices will decline – but uncertainty remains**
  - Unclear what the Huron Study assumed for titanium prices



CGS Condenser Replacement Project

ACPRT Review

Presentation to the CAB *September 2008*

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Methodology

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Scope of review

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Modular titanium replacement	**5,535**	**(668)**
Titanium retube with new tubesheets	**(103,803)**	**(90,873)**

  - Modular replacement otherwise preferable to re-tubing alternative
    - less contamination risk, less risk of damage to tubes during installation (extends length of outage)*, improved thermal performance*

* Note: The Huron Study cited these as benefits of the modular replacement alternative that are above and beyond the NPV-financial benefits. In fact, these factors were captured in the NPV-financial analysis.

Scope of review

- **ENW justified and approved the project based on the Huron Study**
  - BPA non-disapproved FY 2008 funding (~$4 million sunk costs) (May 2007)
  - BPA has also non-disapproved FY 2009 funding (May 2008)
  - Procurement contract non-disapproval decision will be due in October
- **The ACPRT's "due diligence" review is focused on the methodology and assumptions Huron used to assess the financial implications of the four alternatives**
- **At the Administrator's direction, the ACPRT's review relies on existing, currently available materials and PGC expertise only**
- **No request has been made for supplemental information from ENW or Huron, and no standardized business case has been submitted**

Scope of review

- **Unlike other project reviews, the ACPRT is making no recommendation on a project alternative**
  - A full business case and access to Huron and to ENW SMEs would be needed first
  - Project execution risks are very large -- and access to a project plan to test risk management planning and controls would also be needed

- **Rather, we provide our critique of the Huron Study and our assessment of the alternatives' financial implications**

Methodology

Huron Study's methodology

- **The Huron Study employed net present value as the metric for determining the alternative that is financially most favorable**
  - Cash flows over the investment's expected life span were developed for each alternative
  - The cash flows for the alternatives were then discounted and compared
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- **In concept, Huron's approach – determine net present values based on life cycle cost and benefit cash flows – comports with BPA's approach to capital project valuation**

Huron Study's methodology

- **The Huron Study process was largely closed to BPA (PGC) and other stakeholder review and comment until it was completed in February 2008**

- **That said, the Study's analytical approach, assumptions, and results are documented**
  - BPA staff were provided access to the spreadsheets Huron used to determine cashflows and NPVs
  - For many data inputs, we know what was assumed but often not why

ACPRT's approach

- **The ACPRT's review was limited to the titanium modular replacement and titanium retube alternatives covered by the Huron Study**
  - We accept ENW's judgment that other alternatives – e.g., copper retube using existing tubesheets and stainless steel modular replacement -- are unacceptable from an operational/technical standpoint
- **ACPRT created a NPV-based model that starts with Huron's spreadsheets**
  - The model allows us to make corrections, updates and enhancements to Huron's analysis

The ACPRT employs the same financial metric, the same life-cycle cash flow approach, and essentially the same source data as Huron

ACPRT's approach

- **No changes were made to Huron's project cost data**
  - In other words, no changes were made to procurement, installation, testing and decontamination/disposal data for the modular replacement and retube alternatives
  - The Huron Study identified ENW and Industry SMEs as sources for these data
  - We had no access to these sources: therefore no ability to test the basis and uncertainties associated with project cost data
- **Updates and enhancements were made to market price and outage assumptions, data, and modeling**
  - to better ascertain the impact of alternatives on lost revenues, increased revenues, and replacement power costs
- **Several methodological and other analytical fixes were also been made to the financial analysis**

Problems found with Huron's modeling

- **Incremental cash flows in the Huron Study were not developed by comparison to a base case**
  - For purposes of determining net present values, cash flows must be incremental cashflows
  - The issue isn't whether the current condenser will need to be replaced or re-tubed – but rather *when* the installation will be most cost-beneficial
  - Therefore, the incremental cash flows for the 2011 and 2015 alternatives should be determined by reference to a "run to failure" base case
    - ACPRT's base case assumes that the current condenser will be replaced or re-tubed in 2018 (estimated end of condenser's useful life – PGC)
  - Modeling in the Huron Study effectively assumed that the current condenser would never fail
    - Some benefits are time-limited, but they were shown to continue over an indefinite period of time
      - *For example, the modular replacement alternative will increase generating capability over the long-term. But for purposes of determining incremental cash flows, these benefits should be counted between 2011 or 2015 and 2018 only*
    - Some benefits were not counted at all
      - *In particular, savings associated with avoiding the need to make a replacement in 2018, when determining incremental cash flows for the 2011 or 2015 alternatives*
  - The net effect of these problems is that the benefits of the alternatives were significantly understated

Problems found with Huron's modeling

- **Lost revenue/replacement power cost estimates did not fully capture market price and outage duration uncertainties**
  - ACPRT is now using BPA's most recent, probabilistic forecast of market prices
  - A "worst case" outage duration case has now been added (incremental 31, 40, and 62 days)
- **A couple of cost factors were improperly treated**
  - For example, eddy current testing (nondestructive testing) costs were calculated on a gross not incremental basis, and they were improperly treated in the cash flows
- **Horizon of cashflows extends beyond estimated useful service life**
  - Horizon of cash flows were limited to 20 years, with an estimate of the condenser's residual value inserted at year 20
    - Not a flaw in Huron's Study, but this change comports with BPA's treatment of other capital projects
    - ACPRT determined the residual value as net book value in year 20
- **Discount rate was not risk-adjusted and inconsistent with BPA's standard**
  - Huron Study: 6.5 percent (reflecting ENW's weighted average cost of capital)
  - ACPRT review: 13.0 percent (risk-adjusted discount rate for Federal hydro and all other capital projects in Power Services)

ACPRT modeling results

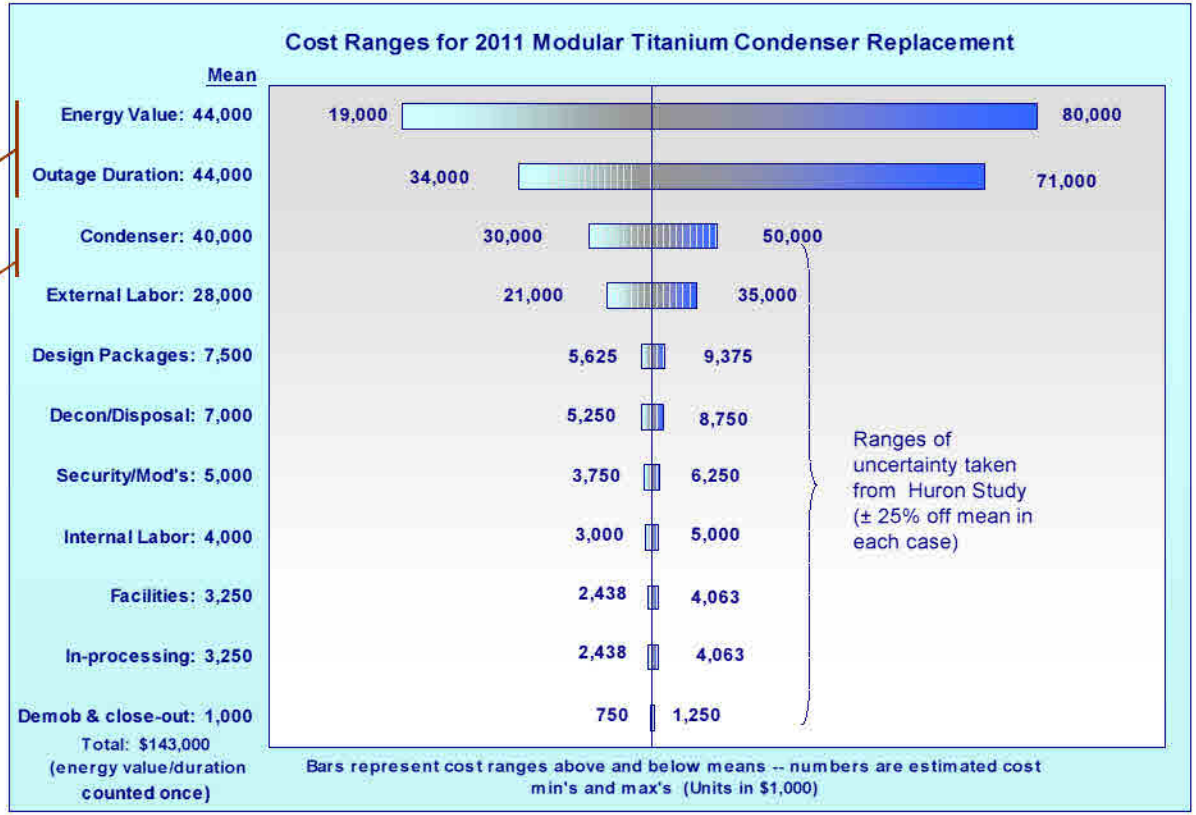
	Expected values					
	2011 Installation			2015 installation		
	Huron Study	ACPRT Review	Difference	Huron Study	ACPRT Review	Difference
Titanium modular replacement						
Project costs	106,370	106,938	568	120,933	120,915	(18)
Lost revenue/replacement power costs	71,756	43,669	(28,087)	80,841	46,739	(34,102)
Total costs	**178,126**	**150,607**	**(27,519)**	**201,774**	**167,654**	**(34,120)**
Net present values	**5,535**	**(20,224)**	**(25,759)**	**(668)**	**(3,599)**	**(2,931)**
Retube - titanium sheets						
Project costs	87,095	87,018	(77)	98,871	101,067	2,196
Lost revenue/replacement power costs	71,073	43,669	(27,404)	80,071	46,739	(33,332)
Total costs	**158,168**	**130,687**	**(27,481)**	**178,942**	**147,806**	**(31,136)**
Net present values	**(103,803)**	**(23,600)**	**80,203**	**(3,172)**	**(8,154)**	**(4,982)**

On an expected value basis, 2015 installation of the modular replacement alternative is the most favorable alternative

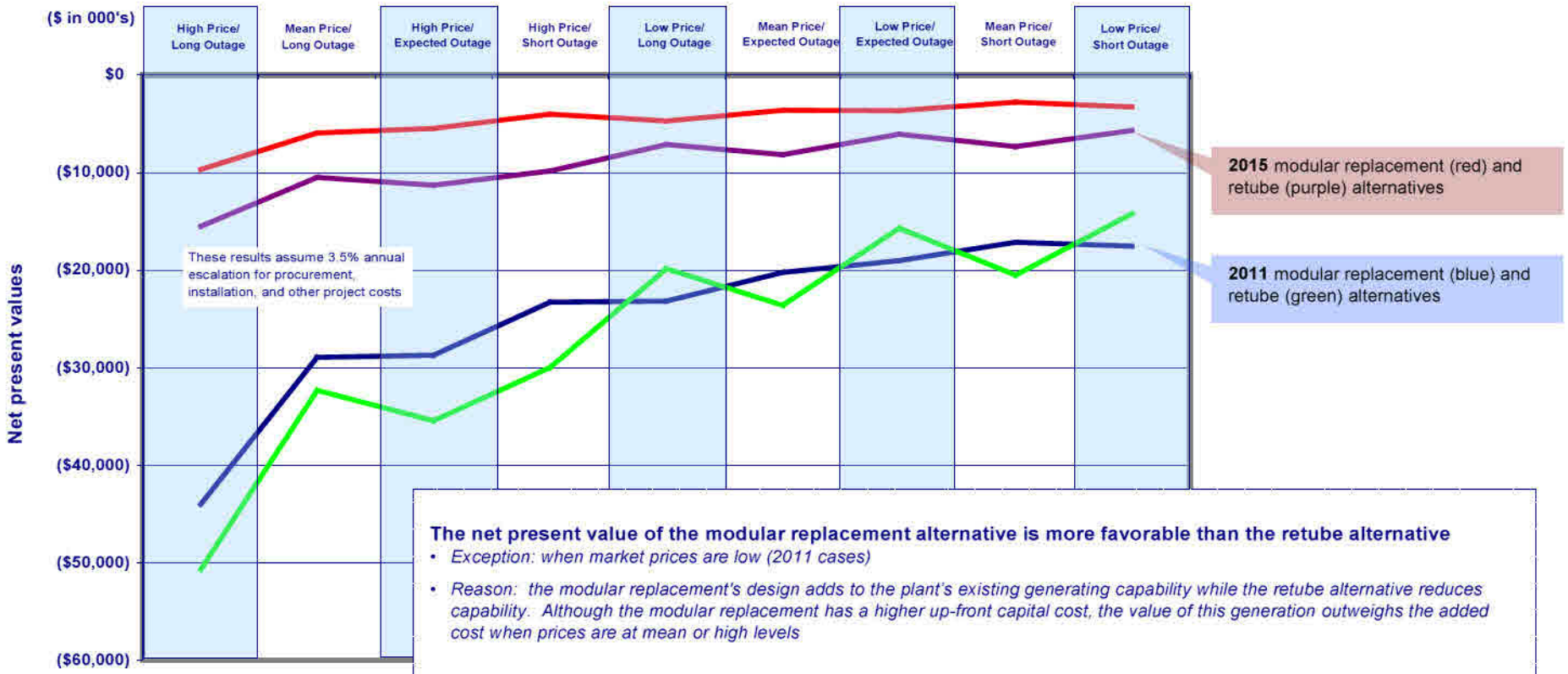
Cost uncertainties are very large

Market price and outage duration uncertainties are the biggest drivers

Procurement cost risks are also big, largely because of titanium price uncertainty. Uncertainty will be reduced in EN's vendor bid process now underway



NPV as a Function of Market Price and Outage Duration Variability



The net present value of the modular replacement alternative is more favorable than the retube alternative

- *Exception: when market prices are low (2011 cases)*
- *Reason: the modular replacement's design adds to the plant's existing generating capability while the retube alternative reduces capability. Although the modular replacement has a higher up-front capital cost, the value of this generation outweighs the added cost when prices are at mean or high levels*

Contrary to the Huron Study's findings, the project's value is improved if the installation date is delayed

- *Reason: In nominal terms, the benefits of this project are greater than its costs over the long haul. When discounting, whatever comes later is discounted more than what comes earlier, and this difference increases as a higher discount rate is applied. If a higher, risk-adjusted discount rate is used, the net present value of long-term project benefits declines relative to early project costs. Therefore, with BPA's discount rate (13.0% Vs Huron Study's 6.5%), pushing project costs out to a later installation date is more economic*
- *2011/2015 results can flip if titanium and other price inflation is significantly higher than the 3.5% rate used in Huron Study*

NPV variability is driven largely by the length of outage and prevailing market prices

- *Lost revenue/replacement power costs can more than double the NPV cost of the current 2011 installation plan*
- *Titanium price risk and other project risks are not reflected in this graph*

Managing cost risks

What could go wrong, and what steps should be taken?

Updated 9/30/2008

	Risks	Controls and Treatments
Timing	Project coincides with big unit outages at GCL results in higher power purchase expenses	• Coordinate with Federal Hydro; get condenser project done before GCL big unit outages (805 mw) begin in late August, 2012, and go on continuously for 10 years. • If condenser project done after 2012, shift the GCL schedule to create an opening for the condenser project
Approval Process	Insufficient information or time for BPA to approve or disapprove "term sheet" results in uninformed decision	• Need to inform PGC and EN that we need information well in advance of the 7 day " non-disapproval" process
	Project team / management doesn't adequately oversee the project resulting in delays and cost overruns	• PGC monitors as best they can and provides early warning of management problems
Cost	Value of lost energy during outage can be greater than estimates when project approved	• Review energy forecasts and prices and outage schedule before outage begins and develop energy strategy
	Titanium price escalates and EN/BPA ends up paying more	• Contractor takes price risk and incorporates it into project costs • EN takes risk and develops hedging strategy • PGC researches industry standard practice, BPA determines whether it has any preferences, and informs EN
Design	Condenser designed incorrectly resulting in delays and cost overruns	• Manufacturers visit CGS to get familiar with the plant and design requirements • EN quality assurance inspectors on site at manufacturer's plant
	Uncertainty about equipment design may cause large labor cost contingency to be built into installation bids	• *Resolve equipment design uncertainties* • *Send out "best and final offer" (BAFO) request with refined work scope* • *Re-do cost/benefit studies* • *EN does work themselves that they would otherwise contract out*

Italics = new actions not underway

Managing cost risks

What could go wrong, and what steps should be taken?

	Risks	Controls and Treatments
Manufacturing	Condenser manufactured incorrectly resulting in delays and cost overruns	• EN quality assurance inspectors on site at manufacturer's plant •
Installation	Overall	• EN develops outage plan and risk management plan • PGC has access to and reviews the outage plan, including the risk management plan • PGC performs on-going high level review of project progress • PGC attends Condenser Project Steering Committee meetings • EN and PGC visiting Laguna Verde as they install new condenser
	Prep work is insufficient (reinforcing structures needed when condenser is removed) resulting in delays and cost overruns	• Contingency plans • EN hiring industry expert consultants who have condenser replacement experience at other plants • EN ready to maintain existing condenser if install doesn't go right
	Labor shortages, possibly up to 400 in welding and other specialized fields, result in needing to extend the planned outage timeline	• Rely on industry practice/culture of sharing employees and contractors during outages • EN plans on barrowing workers from mid-west nuclear facilities • Summer outage at CGS won't coincide with the outage season in mid-west
	Something fundamentally flawed with the installation plan or CGS unable to receive a correctly designed condenser	• Outage plan reviewed by other utilities, manufacturers, BPA, others? • CGS visiting other plants to gather insights
	Equipment problems (e.g. Gantry crane can't be supported by CGS floor) resulting on delays and cost overruns	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
	Incorrect installation resulting on delays and cost overruns	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
	Schedule slippage	• Installer contract incentives
	Damage to condenser during installation	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
Restart	Plant doesn't restart as planned resulting in lost energy sales revenues or power purchase expenses	• Shake-out period incorporated into the scheduled outage duration • *Bulk Hub hedges forecasted extended outage period deficits with purchases, options, financials, etc., hedging any forecasted outage period surpluses by selling more cautiously*

Italics = new actions not underway

9/20/08
Version.

CGS Condenser Replacement Project

ACPRT Review

Presentation to the CAB *September 2008*

Version sent out
9/20/08 e-mail
from Mary Hawken.

Scope
Methodology
Results

Scope and purpose

Scope of review

- **The Huron Study assessed the financial implications of two, operationally viable project alternatives under two installation timeframes**
  1. Titanium modular replacement installed in 2011
  2. Titanium modular replacement installed in 2015
  3. Titanium retube with new tubesheets in 2011
  4. Titanium retube with new tubesheets in 2015

- **The Huron Study concluded that alternative 1 – Titanium modular replacement installed in 2011 – was preferable**
  - Financially most advantageous

Net present values

(Expected values - $000)

	2011	2015
Modular titanium replacement	**5,535**	**(668)**
Titanium retube with new tubesheets	**(103,803)**	**(90,873)**

  - Modular replacement otherwise preferable to re-tubing alternative
    - less contamination risk, less risk of damage to tubes during installation (extends length of outage)*, improved thermal performance* high installation risk of trying to retube.

* Note: The Huron Study cited these as benefits of the modular replacement alternative that are above and beyond the NPV-financial benefits. In fact, these factors were captured in the NPV-financial analysis.

Scope of review

- **ENW justified and approved the project based on the Huron Study**
  - BPA non-disapproved FY 2008 funding (~$4 million sunk costs) (May 2007)
  - BPA has also non-disapproved FY 2009 funding (May 2008)
  - Procurement contract non-disapproval decision will be due in October
- **The ACPRT's "due diligence" review is focused on the methodology and assumptions Huron used to assess the financial implications of the four alternatives**
- **At the Administrator's direction, the ACPRT's review relies on existing, currently available materials and PGC expertise only**
- **No request has been made for supplemental information from ENW or Huron, and no standardized business case has been submitted**

Scope of review

- **Unlike other project reviews, the ACPRT is making no recommendation on a project alternative**
  - A full business case and access to Huron and to ENW SMEs would be needed first
  - Project execution risks are very large -- and access to a project plan to test risk management planning and controls would also be needed

- **Rather, we provide our critique of the Huron Study and our assessment of the alternatives' financial implications**

Methodology

Huron Study's methodology

- **The Huron Study employed net present value as the metric for determining the alternative that is financially most favorable**
  - Cash flows over the investment's expected life span were developed for each alternative
  - The cash flows for the alternatives were then discounted and compared
- **The Study then recommended the alternative shown to have the most favorable NPV**
- **In concept, Huron's approach – determine net present values based on *life cycle cost and benefit cash flows – comports with BPA's approach* to capital project valuation**

Huron Study's methodology

- **The Huron Study process was largely closed to BPA (PGC) and other stakeholder review and comment until it was completed in February 2008**

- **That said, the Study's analytical approach, assumptions, and results are documented**
  - BPA staff were provided access to the spreadsheets Huron used to determine cashflows and NPVs
  - *For many data inputs, we know what was assumed but often not why*

ACPRT's approach

- **The ACPRT's review was limited to the titanium modular replacement and titanium retube alternatives covered by the Huron Study**
  - We accept ENW's judgment that other alternatives – e.g., copper retube using existing tubesheets and stainless steel modular replacement -- are unacceptable from an operational/technical standpoint

only focused on two alternatives

- **ACPRT created a NPV-based model that starts with Huron's spreadsheets**
  - The model allows us to make corrections, updates and enhancements to Huron's analysis

The ACPRT employs the same financial metric, the same life-cycle cash flow approach, and essentially the same source data as Huron

ACPRT's approach

- **No changes were made to Huron's project cost data**
  - In other words, no changes were made to procurement, installation, testing and decontamination/disposal data for the modular replacement and retube alternatives
  - The Huron Study identified ENW and Industry SMEs as sources for these data
  - We had no access to these sources: therefore no ability to test the basis and uncertainties associated with project cost data
- **Updates and enhancements were made to market price and outage assumptions, data, and modeling**
  - to better ascertain the impact of alternatives on lost revenues, increased revenues, and replacement power costs
- **Several methodological and other analytical fixes were also been made to the financial analysis**

Problems found with Huron's modeling

- **Incremental cash flows in the Huron Study were not developed by comparison to a base case**
  - For purposes of determining net present values, cash flows must be incremental cashflows
  - The issue isn't whether the current condenser will need to be replaced or re-tubed – but rather *when* the installation will be most cost-beneficial
  - Therefore, the incremental cash flows for the 2011 and 2015 alternatives should be determined by reference to a "run to failure" base case — run to 2018
    - ACPRT's base case assumes that the current condenser will be replaced or re-tubed in 2018 (estimated end of condenser's useful life – PGC)
  - Modeling in the Huron Study effectively assumed that the current condenser would never fail — So they didn't have a base case
    - Some benefits are time-limited, but they were shown to continue over an indefinite period of time
      - *For example, the modular replacement alternative will increase generating capability over the long-term. But for purposes of determining incremental cash flows, these benefits should be counted between 2011 or 2015 and 2018 only*
    - Some benefits were not counted at all
      - *In particular, savings associated with avoiding the need to make a replacement in 2018, when determining incremental cash flows for the 2011 or 2015 alternatives*
  - The net effect of these problems is that the benefits of the alternatives were significantly understated

Problems found with Huron's modeling

— they used $50M point value.

- **Lost revenue/replacement power cost estimates did not fully capture market price and outage duration uncertainties**
  - ACPRT is now using BPA's most recent, probabilistic forecast of market prices
  - A "worst case" outage duration case has now been added (incremental 31, 40, and 62 days)

— so created a distribution

- **A couple of cost factors were improperly treated**
  - For example, eddy current testing (nondestructive testing) costs were calculated on a gross not incremental basis, and they were improperly treated in the cash flows

- **Horizon of cashflows extends beyond estimated useful service life**
  - Horizon of cash flows were limited to 20 years, with an estimate of the condenser's residual value inserted at year 20
    - Not a flaw in Huron's Study, but this change comports with BPA's treatment of other capital projects
    - ACPRT determined the residual value as net book value in year 20

- **Discount rate was not risk-adjusted and inconsistent with BPA's standard**
  - Huron Study: 6.5 percent (reflecting ENW's weighted average cost of capital)
  - ACPRT review: 13.0 percent (risk-adjusted discount rate for Federal hydro and all other capital projects in Power Services)

→ mandated for use for all Power Services Projects

ACPRT modeling results

reflects lower price forecast

Modeling results

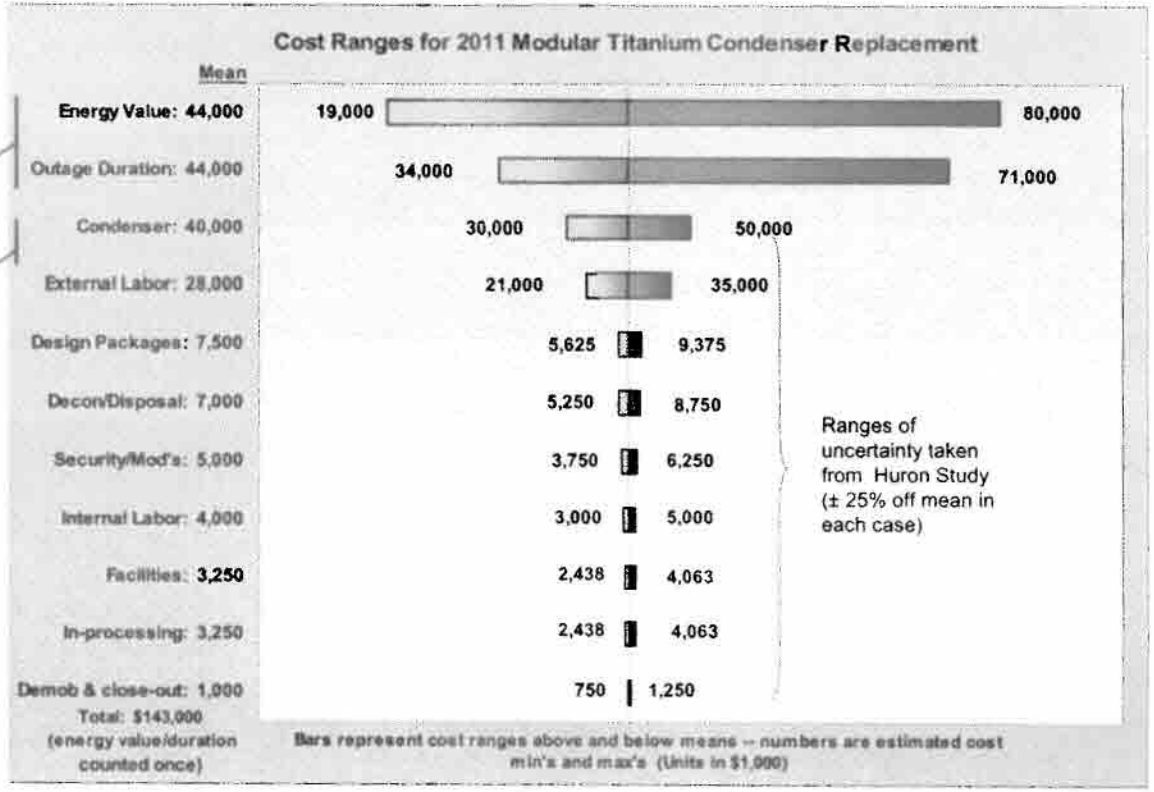
	Expected values					
	2011 Installation			2015 installation		
	Huron Study	ACPRT Review	Difference	Huron Study	ACPRT Review	Difference
Titanium modular replacement						
Project costs	106,370	106,938	568	120,933	120,915	(18)
Lost revenue/replacement power costs	71,756	43,669	(28,087)	80,841	46,739	(34,102)
Total costs	**178,126**	**150,607**	**(27,519)**	**201,774**	**167,654**	**(34,120)**
Net present values	**5,535**	**(20,224)**	**(25,759)**	**(668)**	**(3,599)**	**(2,931)**
Retube - titanium sheets						
Project costs	87,095	87,018	(77)	98,871	101,067	2,196
Lost revenue/replacement power costs	71,073	43,669	(27,404)	80,071	46,739	(33,332)
Total costs	**158,168**	**130,687**	**(27,481)**	**178,942**	**147,806**	**(31,136)**
Net present values	**(103,803)**	**(23,600)**	**80,203**	**(3,172)**	**(8,154)**	**(4,982)**

On an expected value basis, 2015 installation of the modular replacement alternative is the most favorable alternative

Cost uncertainties are very large

Market price and outage duration uncertainties are the biggest drivers

Procurement cost risks are also big, largely because of titanium price uncertainty. Uncertainty will be reduced in EN's vendor bid process now underway

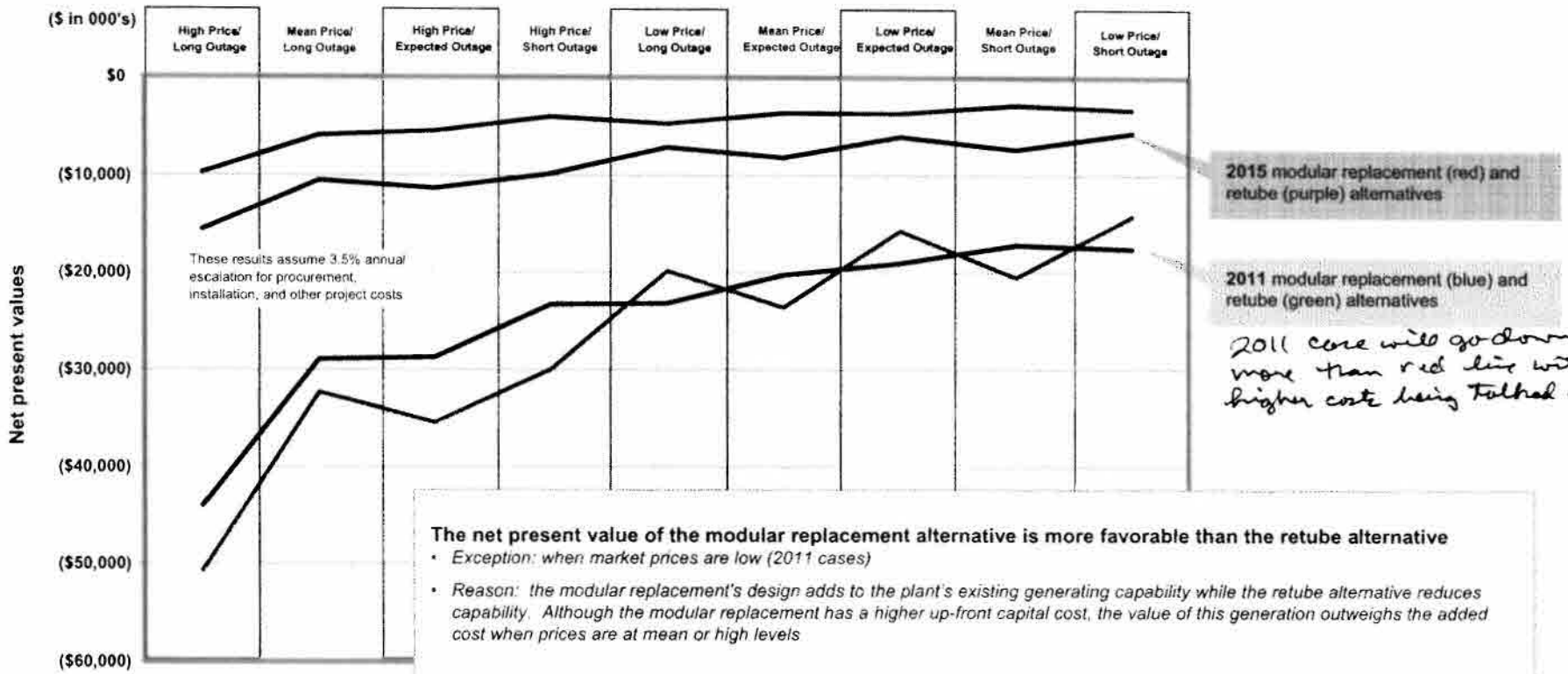


It's not just the module, its also the installation design + work

9/23/2008

06 → 120m → 136m

NPV as a Function of Market Price and Outage Duration Variability



2011 case will go down more than red line with higher costs being talked about.

The net present value of the modular replacement alternative is more favorable than the retube alternative

- *Exception: when market prices are low (2011 cases)*
- *Reason: the modular replacement's design adds to the plant's existing generating capability while the retube alternative reduces capability. Although the modular replacement has a higher up-front capital cost, the value of this generation outweighs the added cost when prices are at mean or high levels*

Contrary to the Huron Study's findings, the project's value is improved if the installation date is delayed

- *Reason: In nominal terms, the benefits of this project are greater than its costs over the long haul. When discounting, whatever comes later is discounted more than what comes earlier, and this difference increases as a higher discount rate is applied. If a higher, risk-adjusted discount rate is used, the net present value of long-term project benefits declines relative to early project costs. Therefore, with BPA's discount rate (13.0% Vs Huron Study's 6.5%), pushing project costs out to a later installation date is more economic*
- *2011/2015 results can flip if titanium and other price inflation is significantly higher than the 3.5% rate used in Huron Study*

NPV variability is driven largely by the length of outage and prevailing market prices

- *Lost revenue/replacement power costs can more than double the NPV cost of the current 2011 installation plan*
- *Titanium price risk and other project risks are not reflected in this graph*

Managing cost risks

What could go wrong, and what steps should be taken?

Ed Blickhaus
Much of this is already occurring
– italics are new

	Risks	Controls and Treatments
Timing	Project coincides with big unit outages at GCL results in higher power purchase expenses	• Coordinate with Federal Hydro; get condenser project done before GCL big unit outages (805 mw) begin in late August, 2012, and go on continuously for 10 years. • *If condenser project scheduled for after 2012, shift the GCL maintenance schedule to create an opening for the condenser project*
Approval Process	Insufficient information or time for BPA to approve or disapprove "term sheet" results in uninformed decision	• *Need to inform PGC and EN that we need information well in advance of the 7 day " non-disapproval" process*
	Project team / management doesn't adequately oversee the project resulting in delays and cost overruns	• PGC monitors as best they can and provides early warning of management problems
Cost	Value of lost energy during outage can be greater than estimates when project approved	• *Review energy forecasts, prices, and outage schedule before outage begins and develop energy marketing strategy*
	Titanium price escalates and EN/BPA ends up paying more	• Contractor takes price risk and incorporates it into project costs • EN takes risk and develops hedging strategy • *PGC researches industry standard practice, BPA determines whether it has any preferences, and informs EN*
Design	Condenser designed incorrectly resulting in delays and cost overruns	• Manufacturers visit CGS to get familiar with the plant and design requirements • EN quality assurance inspectors on site at manufacturer's plant
Manufacturing	Condenser manufactured incorrectly resulting in delays and cost overruns	• EN quality assurance inspectors on site at manufacturer's plant

– Not a good option for BPA

Italics = new actions not underway

Managing cost risks

What could go wrong, and what steps should be taken?

	Risks	Controls and Treatments
Installation	Overall	• EN develops outage plan and risk management plan • *PGC has access to and reviews the outage plan, including the risk management plan, and shares information with the ACPRT* • PGC performs on-going high level review of project progress • PGC attends Condenser Project Steering Committee meetings • EN visiting Laguna Verde and Limerick as they install new condenser
	Prep work is insufficient (reinforcing structures needed when condenser is removed) resulting in delays and cost overruns	• Contingency plans • EN hiring industry expert consultants who have condenser replacement experience at other plants • EN ready to maintain existing condenser if install doesn't go right
	Labor shortages, possibly up to 400 in welding and other specialized fields, result in needing to extend the planned outage timeline	• Rely on industry practice/culture of sharing employees and contractors during outages • EN plans on barrowing workers from mid-west nuclear facilities • Summer outage at CGS won't coincide with the outage season in mid-west
	Something fundamentally flawed with the installation plan or CGS unable to receive a correctly designed condenser	• Outage plan reviewed by other utilities, manufacturers, BPA, others? • CGS visiting other plants to gather insights
	Equipment problems (e.g. Gantry crane can't be supported by CGS floor) resulting on delays and cost overruns	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
	Incorrect installation resulting in delays and cost overruns	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
	Schedule slippage	• *Installer contract incentives*
	Damage to condenser during installation	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
Restart	Plant doesn't restart as planned resulting in lost energy sales revenues or power purchase expenses	• Shake-out period incorporated into the scheduled outage duration • *Bulk Hub hedges forecasted extended outage period deficits with purchases, options, financials, etc., while hedging any remaining forecasted outage period surpluses by selling more cautiously*

Italics = new actions not underway

Managing cost risks *(3)*

- **What are the other procurement contract risks?**
  - (to be added)

- **What should the objectives be to manage these risks?**
  - (to be added)

- **What steps should be taken?**
  - (to be added)

Public Power Council

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May 5, 2006

Paul Norman
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Bonneville Power Administration
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P.O. Box 14428
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Re: PPC's PFR II Comments and CGS Condenser Replacement

As a result of discussion at its May 4 Executive Committee meeting, the Public Power Council would like to clarify our comments on Power Function Review (PFR) II regarding the issue of the condenser replacement at the Columbia Generating Station (CGS). In our April 26th comments, we said: "We do, however, question the timing of the funding for the main condenser replacement, given that the planning and design has not yet been fully developed and other alternatives have not yet been explored. Given that there is $35 million in placeholder capital costs for the condenser replacement in the spending estimates for the FY07-09 period, we are interested in the follow-up report on this investment."

As also noted in our April 26th comments, "BPA's customers recognize that the reliable and safe operation of CGS is essential to BPA's power portfolio." Taken together, these statements should *not* be read to mean that the condenser should not be replaced. Rather, if replacement is deemed necessary after consideration of the alternatives, then the condenser should be replaced. Also as BPA notes in its PFR II draft closeout report, "BPA customers expressed interest in receiving a follow-up report on EN's plan in regard to condenser replacement and EN and BPA intend to provide this follow up." BPA's customers remain interested

in follow-up discussions on this topic, to gain additional understanding of the different ways ENW had researched to address its main condenser problems.

Thank you for the opportunity to make this clarification.

Sincerely,

Marilyn Showalter
Executive Director

Public Power Council

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April 26, 2006
Via Electronic Mail

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Re: Comments on BPA's Power Function Review II Draft Closeout Report

Dear Mr. Norman:

As the second phase of the Power Function Review process (PFR II) approaches its end, PPC would like to offer some observations and comments for your review, based on your draft closeout report issued on April 4. PPC has again coordinated the responses of a number of groups that have been following this process. We found the PFR II process to be fair, open, cooperative, and creative, and we were encouraged by the level of commitment of all parties to share and understand information on BPA's cost drivers. We especially want to thank you, Michelle Manary, Nita Burbank, and many others for your efforts in making PFR II a constructive process. Further, building on the PFR II experience, we hope to meet more regularly with representatives from the Corps of Engineers (Corps), Bureau of Reclamation (Bureau), EnergyNorthwest (EN), and the Northwest Power and Conservation Council (Council) to deepen our understanding of their budgets and their relation to BPA's budget.

Our sincere appreciation of the PFR II process, and of many of the cooperative ideas and actions arising out of that process, does not mean we agree with *all* of

the results of the process. In that regard, as you draft your final closeout report, we urge you and BPA's sister-agencies to consider the following:

SUMMARY OF RECOMMENDATIONS

- **Extend amortization for conservation investments to 15 years.**
- **Extend amortization for F&W investments to greater than the minimum of 15 years.**
- **Inform customers of EN capital investment plans well-prior to final decision.**
- **Modestly increase forecasted output of Columbia Generating Station (CGS).**
- **Implement the hydro-benchmarking study and associated savings.**
- **Shift F&W funds from R, M & E to direct-benefit projects.**
- **Do not exceed $40 million in DSI benefits.**
- **Accelerate implementation of EPIP Phase One and reduce Internal Operations costs by an additional $4 million/year.**
- **Adjust conservation target by incorporating utility-funded projects, as appropriate.**
- **Remove Fourmile Hill project from this rate period, model the facilitation budget through NORM, and initiate a new facilitation funding process.**
- **Include customers in the Council's budget-planning process.**
- **Initiate on-going examination of forecasted budgets, with appropriate customer participation.**

COMMENTS AND RECOMMENDATIONS

A. Capital Cost Recovery

1. Extend amortization for conservation investments to 15 years. In general, we encourage BPA to match debt life with the life of the investment because this principle comports with sound business practices and better matches the recovery of costs from those that benefit from an asset. BPA has pointed to the Council's study, which found a median of a 15-year asset life for conservation investments installed after FY06. Accordingly, we recommend that BPA adopt a 15-year amortization period for its capitalized conservation investments, instead of the 5-year period assumed in the draft closeout report. Although this change does not significantly affect rates in the near term, after 2011 rates will be modestly relieved. Further, this change will make the amortization period comport more closely with the 20-year amortization period assumed for conservation before the new policy of debt financing over 5 years went into effect.

2. Extend amortization for F&W investments to greater than the minimum of 15 years. Similarly, we believe BPA should expand the assumed amortization period for Fish and Wildlife investments because using the 15-year period seems to reflect only the minimum life associated with these investments. A longer period should be assumed in order to reflect the average life of all the capitalized Fish and Wildlife investments in BPA's direct program

3. Inform customers of EN capital investment plans well-prior to final decisions. We would like to continue to be informed of discussions with EN about the wisdom of the capital improvements proposed for the FY07-09 period. The region helped the EN Executive Board make an informed decision regarding the proposal to extend the outstanding CGS debt past 2018 based on the costs and benefits of the proposal. We see this model as one to follow for future CGS-related debt and capital decisions.

B. Modestly increase forecasted output of Columbia Generating Station (CGS).

The operating costs of CGS (at 9% of BPA costs) represent a significant percentage of BPA's total costs. The recovery of CGS capital costs is more than 18% of BPA's total costs. While these costs represent a significant cost category, BPA's customers recognize that the reliable and safe operation of CGS is essential to BPA's power portfolio. The customers intend, however, to become more

active in the EN budget process prior to the time these costs show up in BPA's rates.

At the PFR II Manager's Meeting on March 8, 2006, CGS described a need for additional funding of $13.8 Million/year for increased O&M and an increase in capital expenditures of $22.9 Million/year on average over FY07-09. These amounts would be in addition to the CGS expenditures included in BPA's Initial Rate Proposal. In the month following this meeting, CGS was able to determine that it could internally fund these additional expenditures through additional revenues from CGS uranium remarketing efforts. The result is no net increase in CGS expenditures over BPA's Initial Rate Proposal, and the effect on BPA's proposed rates is now forecasted to be a net decrease of $2 Million/year due to forecasted increased revenues from uranium remarketing.

We commend CGS for finding innovative ways to offset the costs of these additional O&M and capital requirements. We also appreciate EN staff's participation in the PFR process and expect that this will lead to better coordination of EN's funding needs and BPA's rates in the future.

We do, however, question the timing of the funding for the main condenser replacement, given that the planning and design has not yet been fully developed and other alternatives have not yet been explored. Given that there is $35 million in placeholder capital costs for the condenser replacement in the spending estimates for the FY07-09 period, we are interested in the follow-up report on this investment.

During the CGS presentation on March 8, Scott Oxenford, VP Technical Services, Energy Northwest, acknowledged that the additional O&M and capital expenditures will improve CGS performance and are expected to increase capacity factor and plant availability of CGS. According to BPA, its "forecast of 1,000 aMW for CGS in non-maintenance months provides an accurate, though slightly conservative estimate of the annual generation potential for CGS." This forecast was prepared in July 2005 and did not incorporate the effect of these additional O&M and capital expenditures. As a result, in its Final Proposal, BPA should modestly increase the BPA forecast for CGS generation output for FY07-09 to a slightly less conservative amount of 1,030 aMW in the non-maintenance months.

C. Implement the hydro-benchmarking study and associated savings.

We continue to feel that better communication is needed among BPA, BPA's customers, and the Corps and Bureau. For example, in PFR I we discovered $1.5 to $1.6 billion of Columbia River Fish Mitigation Studies that were coming into plant-in-service that had not been anticipated by the customers. During the course

of PFR II we found that the Corps was considering a $30 million Flood Control Review Feasibility Study. We seriously question the advisability of this study and object to the use of ratepayer monies as a source of funding for this study of non-power uses of the FCRPS. (PPC and many others have written separate letters to the Corps on this subject.)

As a result of our review of the Northwest Regional Benchmarking Study, we find that there are significant areas for saving money in the following areas and look forward to the potential for savings from implementation of these initiatives:

- Automation of facilities
- Review of the system-wide water management function
- Sharing of maintenance practices

The customers look forward to meeting more frequently with the Corps and Bureau as we address the above topics.

D. Shift Fish & Wildlife funds from R, M & E to direct-benefit projects.

Customers believe that the $143 million Direct Program funding level as established in the 2005 PFR is fully adequate for BPA to meet its obligations under the Power Act and the Endangered Species Act (ESA). Customers continue to support BPA's initiative to increase the allocation of the Direct Program to 'on-the-ground' projects, like habitat protection and enhancement, tributary passage improvements, and hatchery improvements. This re-allocation serves two worthwhile purposes. First, by moving funds from research, monitoring, and evaluation (R, M &E) to on-the-ground projects, more money is made available to support programs that directly benefit fish. Second, such a re-allocation initiates a timely re-focusing of the region's R, M, & E efforts by reducing redundancies and building efficiencies into those programs.

We have also requested that BPA pursue cost-sharing of R, M, & E in order to better focus ratepayer funds on programs of direct benefit to fish and wildlife. We appreciate the direction that BPA has been taken in both of these areas and—regardless of BPA's financial situation—will continue to advocate for a program based on science and focused on cost-effective efforts to enhance fish and wildlife.

Finally, customers remain concerned about the Corps of Engineers' Columbia River Fish Mitigation funding assumptions. Customers are still unclear about what underlies the Corps' estimate of $1.6 billion to be spent in this program by the time it is completed. A fully formed rationale for these expenditures is necessary before such a large amount of funding is committed.

E. Do not exceed $40 million in DSI benefits.

PPC appreciates BPA's postponement of its decision, until after the conclusion of PFRII, about whether to sign the DSI contracts. Deferring that decision to this point has given BPA and its customers more time and information for assessing whether providing DSI benefits, or at what level, is appropriate.

In its Draft PFR II closeout letter, BPA determined that it would continue to propose the level of DSI benefits at $59 million per year. PPC does not support this level of benefits being provided to the DSIs through contracts for the 2007-11 period. PPC's position on the level of DSI benefits has not changed since PPC's comments on BPA's "straw proposal" for DSI service in March 2005. At that time, BPA had proposed a level of benefits to the DSIs not to exceed $40 million per year. PPC stated that if BPA was resolved to provide benefits, then those benefits should in no case exceed the proposed level of $40 million per year.

Since that time, BPA determined in its June 30, 2005, Record of Decision on Service to the Direct Service Industries for the Years FY07-11 (DSI ROD) that it would offer the DSIs $59 million per year. PPC notes that this amount is roughly a 50 percent increase over the level BPA presented in its straw proposal, and is thus a significant increase above the level at which PPC has stated the levels should be capped.

BPA's decision to offer the DSIs $59 million per year is not justified. As explained below, BPA appears to have changed its stated criteria for determining the appropriate level of DSI benefits since the June 30, 2005, DSI ROD. In that document, BPA assured customers that it would reconsider whether $59 million per year was an appropriate level of benefits for the DSIs during the FY07-11 period, in light of a likely increase in the operational costs of the FCRPS flowing from litigation over the 2004 Biological Opinion.[1] The DSI ROD clearly set out the standard by which BPA would undertake such a review. It explained:

> On June 10, 2005, the United States District Court for the District of Oregon issued an injunction that, if sustained on appeal, will likely greatly reduce the amount of water available this summer for hydroelectricity production. . . . *If this injunction is sustained on appeal, and especially if summer spill along the lines ordered in the injunction is made a regular*

[1] *See, e.g.*, DSI ROD at p. 26 ("BPA will review its decision . . . after the cost impact of the June 10, 2005, injunction becomes more clear . . . . A decision to reduce the amount of service benefits . . . up to and including a decision not to serve any aluminum smelter load, is possible.").

> *part of river operations, the rate impacts would be of extreme concern, and BPA may seek offsetting cost reductions.*[2]

BPA acknowledged, therefore, that its proposed level of benefits may indeed *not be appropriate* if 1) the June 10, 2005, injunction was sustained on appeal, and 2) summer spill along the lines ordered in the June 10, 2005, injunction were made a regular part of river operations. Subsequent to the DSI ROD, both of these conditions were realized—the Ninth Circuit Court of Appeals affirmed the District Court's spill injunction, *and* the District Court, on December 29, 2005, ordered river operations that are very similar in cost to what the June 10, 2005, injunction cost. PPC is unaware of any information indicating a likely return to a more flexible operating system.

However, in its draft closeout report, BPA offers no meaningful explanation of how the level of DSI benefits was considered in light of these stated criteria. Instead, BPA states:

> The additional review time has provided an opportunity to consider the DSI benefit levels in *light of more recent information on expected hydro system operations and a more refined understanding of net secondary revenues BPA will achieve during FY06.* In light of discussions in the PFR II and the updated information on expected hydro operations and revenues, BPA proposes to retain the maximum DSI benefit level at $59 million per year.[3]

This explanation is unpersuasive, and seems to indicate a willingness to take secondary revenues that should be available to reduce rates for preference customers and instead use those revenues to provide a subsidy to the DSIs. It also demonstrates that BPA's determination of the level of DSI benefits relied on a different standard than set forth in the June DSI ROD. In sum, BPA seeks to justify retaining the $59 million annual benefit level based on a better-than-expected net secondary revenues forecast for FY06.

This rationale both differs from the criteria stated in the DSI ROD and is a flawed standard for determining the appropriate level of DSI benefits for a 5-year period. BPA well knows that secondary revenues can vary dramatically from year to year. One year (FY06) of good net secondary revenues is not a sound basis for asserting that $59 million per year is a sustainable and reasonable level of benefits.

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[2] DSI ROD at p. 12 (emphasis added); The DSI ROD also stated that BPA will review this decision prior to contracts being signed pursuant to this ROD based on more current information about the implications of the District Court's decision *and its impact on future hydro system operations*." *Id.* (emphasis added).
[3] Draft Closeout Report at p. 9.

In the draft closeout report, BPA states that "the updated information on expected hydro operations" is a factor that partly supports its decision. Since the "expected hydro system operations" are exactly those feared at the time of the DSI ROD, they do not justify retaining the benefits.

PPC stands by its position that if BPA is intent on providing the DSIs benefits, they should be no more than $40 million per year. If that benefit is not large enough to be of value to the smelters, then BPA must abide by what it recognized in the DSI ROD—that "it is not . . . within BPA's ability, to guarantee any particular level of DSI operations, even minimal levels" since "[w]orld aluminum prices, raw materials costs, and the financial health of the companies are beyond BPA's control and play at least as large a role in the feasibility of smelter operations as power prices."

F. Accelerate implementation of EPIP Phase One and reduce Internal Operations costs by an additional $4 million/year.

PPC commends BPA for its extensive efforts to date in the Enterprise Process Improvement Program (EPIP).

In BPA's "Enterprise Process Improvement: Marketing & Sales Project Report" that was published in February 2006, BPA acknowledges that strategic objectives of "superior customer service" and "a customer-focused culture" direct its efforts. PPC commends BPA for focusing on these two critical strategic objectives and believes these strategic objectives apply to the entire BPA organization and not just to the Marketing & Sales areas.

During PFR II, BPA has continued to confirm its early estimate of savings from EPIP Phase One studies and its assessment that early process-improvement efforts should be limited to $8 Million/year on average for FY 2007-2009. BPA estimates that power-cost savings from EPIP in the $11 million to $12 million annual range should be achievable over time, but not by FY 2007. BPA also states that some of the EPIP process-improvement activities will take three to five years to complete.

PPC recommends that BPA move ahead as quickly as possible to implement all the process improvements and savings that have been clearly identified and documented in the EPIP Phase One reports. BPA has expended considerable effort in completing the six reports in EPIP Phase One. Timely and effective implementation over 1-2 years, rather than a 3-5 year timeframe, is critical to gaining more efficiencies in each of the six areas. PPC recommends that BPA include additional savings of $4 million/year to the early estimate of $8 million/year and that a total of $12 million/year for EPIP savings be included in

BPA's Final Proposal. We believe this recommendation is further bolstered by the fact that EPIP Phase Two and Three will also be completed in the near future and will produce additional savings for BPA's Power Business Line, beyond those associated with the $11-12 million quoted above.

G. Adjust conservation target by incorporating utility-funded projects, as appropriate.

We support the creation of a system for utilities to report the additional conservation they are achieving, and we hope that this information will be used to adjust BPA's target for conservation if it shows utilities are pursuing more than their share of the Council's regional conservation target. At this point in time we do not support any changes to the budget for BPA's conservation rate credit program. There are new requirements of the program, and these may prove very challenging to comply with. We should first see how successful this program is in practice before budget changes are incorporated.

A related concern involves how future conservation achievements (post 2006) will be treated in the post-2011 world. The Regional Dialogue Process has not officially come to a close, so it is difficult to say whether there will be disincentives to do conservation as a result of the decisions made in that process, but we encourage BPA to endeavor to avoid such disincentives.

H. Remove Fourmile Hill project from this rate period, model the facilitation budget through NORM, and initiate new facilitation funding process.

We support BPA's decision to remove from the FY09 renewables budget the costs associated with the Fourmile Hill Geothermal project. In addition, we are encouraged by the change in how BPA now proposes to treat its facilitation budget in rates FY07-09. It better reflects the uncertainty at this point regarding actual usage of the funds available to utilities for renewable facilitation. We want to start the process with BPA to determine how best to use these funds.

As with conservation achievements post-2006, we are concerned about how utility-developed renewable resources will be treated in post-2011 world. We hope that as BPA refines its Regional Dialogue closeout documents, it will avoid creating disincentives to utility-developed renewable resources.

I. Include customers in the Council's budget-planning process.

The customers intend to become more active in the review of the Council's budget before it enters the realm of BPA cost recovery. During the public Council budget-review period, we will request that the Council present to the customers its

proposed budgets at the ongoing BPA financial-review meetings that are held at PPC.

J. Initiate on-going examination of forecasted budgets, with appropriate customer participation.

In both the current PFR process and its predecessor, we have found that some areas we might think would be ripe for additional cost efficiencies are actually less flexible as the rate period nears. From this we conclude that a cost review for the next rate period (FY10-11) should get underway sooner than mid FY08. However, because *other* areas *are* ripe for change with short notice prior to the start of a rate period, we encourage an additional examination of the FY10-11 costs in FY09 during the rate case (similar to the PFR II process). Similarly, we would like to see the promised capital program process begin this summer and offer customers with sufficient opportunity for debate, discussion, and comment before capital commitments are made.

In addition, in the next few years BPA will be negotiating and signing new, long-term power contracts with preference customers that will commence service in the post-2011 period. BPA and preference customers will be able to make more informed decisions if the budget process for the post-2011 period is started at the earliest possible date. Doing so will allow customers to understand the spending trade-offs and participate in the decisions regarding BPA's spending commitments, which will drive the level of BPA's rates in the post-2011 period.

In conclusion, thank you for conducting a constructive PFR II process, and for considering these recommendations and comments for achieving even more fruitful results. If you have any questions, please feel free to contact me or Annick Chalier, achalier@ppcpdx.org.

Sincerely,

Marilyn Showalter
Executive Director

From: Wright,Stephen J (BPA) - A-7
Sent: Friday, December 19, 2008 9:33 AM
To: Oliver,Stephen R (BPA) - PG-5; Ex 6 : Rapacz,Andy (BPA) - PGC-
Ex 6 Ex 6
Cc: Ex 6
Subject: RE: CGS Condenser Tube decision - Economic Stimulus??

In addition to our conclusion in yesterday's conversation I agree that this is not an appropriate stimulus item and is something we should just move forward with.

From: Oliver,Stephen R - PG-5
Sent: Thursday, December 18, 2008 12:38 PM
To: Ex 6 Rapacz,Andy - PGC-RICHLAND; Wright,Stephen J - A-7; Ex 6 Ex 6
Cc: Ex 6
Subject: RE: CG5 Condenser Tube decision - Economic 5timulus??

Andy and I discussed this over the past couple of days and arrived at the same place as Paul. The only thing that caused us any pause, is that we have expressed significant concern that EN remain within budget and have been particularly interested the condenser project. This modification could/would likely(?) create the need for EN to request a mid year budget increase that we would need to approve, and it really doesn't create jobs. All that being said, it has a rapid return on investment and seems like a straight forward decision.

Stephen R. Oliver

From: Ex 6
Sent: Thursday, December 18, 2008 12:29 PM
To: Rapacz,Andy - PGC-RICHLAND; Wright,Stephen J - A-7; Ex 6 Oliver,Stephen R - PG-5; Ex 6
Ex 6
Cc: Ex 6
Subject: RE: CGS Condenser Tube decision - Economic Stimulus??

It's a no-brainer economically if we believe the numbers and if there is no incremental risk created by going to smaller diameter. I think we should find the $ promptly and not dink around with economic stimulus on something so small and easily justified on its own and clearly within our capability.

From: Rapacz,Andy - PGC-RICHLAND
Sent: Wednesday, December 17, 2008 4:28 PM
To: Wright,Stephen J - A-7; Ex 6 Oliver,Stephen R - PG-5; Ex 6 Ex 6
Cc: Ex 6 Rapacz,Andy - PGC-RICHLAND
Subject: CG5 Condenser Tube decision - Economic 5timulus??
Importance: High

All:

During the 12-15-08 condenser steering committee meeting, I was asked about the availability of "economic stimulus" funds (there was quite an article in the Tri-City Herald over the weekend suggesting the new administration may be making economic stimulus monies available to BPA to help stimulate the economy). The inquiry was made in the following context.

EN has a technical decision to make on a relatively short fuse (two to three weeks), regarding selection of condenser tube size for the new condenser.
The decision has been narrowed down to selection of one of two possible tubes sizes; one (1) inch and 7/8 inch. The 1" tube condenser configuration costs less because the number of tubes is less, therefore there is less titanium used and fewer tubes manufactured. However, the 7/8" tube size results in slightly improved overall efficiency, such that generation

will be 2.7 MWe more compared to the 1" tube size [the total tube surface area and heat transfer capability is greater with the use of the 7/8 " tube design]. Separate from this tube decision, it is projected that the new condenser will produce at least 12 MWe more than the existing design, and incentives/penalties are being built into the vendor's contract. (the existing CGS condenser has 1" tubes)

As part of the decision process, EN has asked for BPA input on the cost vs. efficiency tradeoff, and the availability of economic stimulus funds. EN has requested feedback from us by December 29th. The business case analysis shows a favorable payback time of 5 years for the additional cost of the 7/8" tubes. EN is looking at other internal funding options and trade-offs, but I agreed to advance to BPA management both the tradeoff question and the particular question of the availability of economic stimulus money.

The complexity of this decision does not seem to rise to the level of producing an agency decision framework template, particularly given that this is an EN decision. The facts are the same as presented here. The tube size decision needs to be provided to the module manufacturer soon in order to support and maintain the module design schedule. The Pro's and Con's of each tube size are summarized below.

I'm looking for some feedback on this issue. Right now I'm leaning towards telling EN that our input is that the $3M investment for 2.7 MWe on a short payback is well worth the investment; but at this time there are no economic stimulus monies available, so EN should pursue other paths (under runs, contingency, other scope reductions, other project deferrals, etc.) to fund the small tube option.

I'm very interested in your thoughts and feedback,
Thanks,
- Andy

One (1) inch tubes:

Pro's

- Project cost is $3 M dollars less than the 7/8 inch tube option.
- Helps bring the condenser project current estimate of $131 M closer to the $106 M budgeted in the long range plan.

Con's

- Less generation (calculated to be 2.7 MWe) due to lower efficiency.
- Lower project costs ($3 M) provides less potential economic stimulus to US economy.

Seven-Eights (7/8) inch tubes:

Pro's

- More generation (calculated to be 2.7 MWe) due to higher efficiency.
- Payback is estimated at 5 years.
- Increased generation is totally "green and carbonless"; no additional fuel is used since this is an efficiency improvement
- Higher project costs ($3 M) potentially provides more economic stimulus to US economy.
    - Economic stimulus impact will be related to the purchase of more titanium and fabrication of additional tubes.

Con's

- Cost $3M more, making it more difficult to reduce the project's cost estimate of $131M to the $106M target budgeted in the long range plan.
- Will be difficult to actually measure a 2.7 MWe increase in electric output.
- Economic stimulus will most likely not be seen in the northwest, or by the Pacific Northwest rate payers.

From: Ex 6
Sent: Wednesday, January 10, 2007 9:52 AM
To: Rapacz,Andy (BPA) - PGC-RICHLAND
Cc: Ex 6 Ex 6 Ex 6
Ex 6 Ex 6
Subject: RE: CGS Condenser replacement Business case analysis - SAVE

Andy,

The attached file has monthly average (flat) prices for CY07-CY15. There are two Alternatives. The first alternative is very consistent with the assumptions we used in the recently finished rate case. The second alternative is more of an internal view of what we think the market is trading for at the current point in time. Alt 2 is higher than Alt 1 but I'm not sure I would call it a "high" case. If you would like a "high" case I can develop one but it would not be done until tomorrow.

[redacted]

From: Rapacz,Andy - PGC-RICHLAND
Sent: Tuesday, January 09, 2007 3:34 PM
To: Ex 6
Cc: Ex 6 Ex 6 Ex 6
Subject: RE: CGS Condenser replacement Business case analysis

Ex 6,
I think we should be ok with an average (flat) rate. We will be using this to calculate costs of the Plant being out of service for a significant number of days, so an average should work OK.

(If you've got a file by LLH & HLR, maybe you could send that up later, we'd just be interested in looking at it, but we won't use all that input in our economic analysis.)

Thanks,
-= Andy

From: Ex 6
Sent: Tuesday, January 09, 2007 3:17 PM
To: Rapacz,Andy - PGC-RICHLAND
Cc: Ex 6
Subject: RE: CGS Condenser replacement Business case analysis

Andy,

Do you want prices by HLH and LLH ? Or is average (flat) o.k. ?

Ex 6

From: Rapacz,Andy - PGC-RICHLAND
Sent: Monday, January 08, 2007 2:36 PM
To: Ex 6 Ex 6

Cc: Ex 6 Ex 6 Ex 6
Subject: RE: CGS Condenser replacement Business case analysis

Thanks Ex 6 , what you've said makes sense.
Friday (as it was getting late in the day) I found myself wondering if somehow we'd lose on both the lost revenue and replacement cost front. But I see the logic of your explanation.
No further questions at this point, thanks for all you help on this issue.
- Andy

From: Ex 6
Sent: Monday, January 08, 2007 12:04 PM
To: Rapacz,Andy - PGC-RICHLAND; Ex 6
Cc: Ex 6 Ex 6 Ex 6
Subject: RE: CGS Condenser replacement Business case analysis

Andy, as I was reading through the below email message I had a question about your #1. You state that you would need a price for both replacement power and lost revenue. I have two thoughts on this - first the price would be the same for both as you would assume that the value of the energy would be what the forecasted market price is and it does not matter if you are using the energy to serve existing load or selling the surplus power into the market.

My second comment is that you only count the value of the lost energy once not twice. You can characterize the loss of energy as forgone revenues OR replacement power but you do not take a double hit. If you characterize it as replacement power you buy the energy at the forecasted energy price and then you are back to where you were (MW wise) when CGS was operating. You now have that purchased power to either serve existing load or sell on the market. Or you can look at it this way - if you do not need the energy to serve existing load (the system is load/resource balanced) then you do NOT go out and "replace" the energy - you just forego the revenue that you would have received from selling the CGS MW's. Either way you are only out the value of the energy one time - not two.

Please let me know if I misinterpreted something or if you have additional questions. Ex 6

From: Ex 6
Sent: Monday, January 08, 2007 7:38 AM
To: Ex 6
Subject: RE: CGS Condenser replacement Business case analysis

See Andy's question about power prices, would Ex 6 be the right guy?

From: Rapacz,Andy - PGC-RICHLAND
Sent: Friday, January 05, 2007 3:31 PM
To: Oliver,Stephen R - PG-5; Ex 6 Ex 6
Cc: Ex 6 Ex 6 Ex 6 Ex 6
Rapacz,Andy - PGC-RICHLAND
Subject: CGS Condenser replacement Business case analysis
Importance: High

Steve, Ex 6 and Ex 6

Energy Northwest has began an evaluation of replacement options for its leaky main condenser. We have meet with EN on two occasions to discus a study that was recently completed by Sargent & Lundy for Energy Northwest and the associated business cases being developed by EN staff. The EN business cases are evaluating; retubing the existing condenser or a modular bundle replacement as compared to a base case of continuing to operate as in the past year (battling leaks) and delaying the replacement of the condenser for six years.

In support of the business cases we have been asked to provide information in regards to power prices and the timing (time of year for the outage). In the past we would have gone to Ex 6 for power cost numbers but today we need some direction as who is the right person to go to for this information and the timing of the outage?

Background: the retubing estimated duration is 68 days (normal refueling outage of 35 days plus an additional 33 days) and the modular replacement is estimated at 120 days (normal refueling outage of 35 days plus an additional 85 days) with the base case assuming a normal spring refueling outage of 35 days.

1. What price should we tell EN to use for replacement power during the extended refueling outage and what price to use for lost revenue during the extended outage? Also do we have any analysis or documentation to back up the pricing info we would provide? EN is using $40/MWh in their draft business cases. (We're assuming we'd take a double hit of 1) lost revenue, plus, 2) cost of replacement power.)

2. The second question is when should the extended refueling outage occur (time of year)? Currently EN business case assumes the replacement would be planned for the spring of 2009 but could slip to 2011 or 2013 based on availability of materials and amount of engineering support needed. Assuming a normal refueling outage starts about 15 May, do we back up the refueling outage start by 33 days to 12 April for the retubing option and by 85 days to 19 February for the modular replacement? (to avoid getting into the July [hot] time frame with an outage)

3. And to support the base case (operation with leaks) what range for the cost of replacement power should be used if CGS took a forced outage (off line) mid cycle to fix a leak (worst case August or January)? We assume if they just did an online repair (a 60% down power for three days) we would take it out of inventory supplemented with some minimal buying unless the system as a whole is capacity limited.

And as always, time is of the essence. EN would like an answer early next week if possible (January 9?). Our understanding is the EN Senior management team will be briefed on this next Thursday.

- Andy & Ex 6

From: Oliver,Stephen R (BPA) - PG-5
Sent: Thursday, May 08, 2008 4:51 PM
To: Wright,Stephen J (BPA) - A-7; Ex 6 Rapacz,Andy (BPA) - PGC-RICHLAND; Ex 6
Subject: RE: CGS capital - run the CGS steam condenser decision through our capital allocation process

Thanks. We will work with Mike to take the condenser investment through the capital review process.

Stephen R. Oliver
Vice President, Generation Asset Management
Bonneville Power Administration
Ex 6

From: Wright,Stephen J - A-7
Sent: Thursday, May 08, 2008 4:03 PM
To: Oliver,Stephen R - PG-5; Ex 6 ; Rapacz,Andy - PGC-RICHLAND; Ex 6
Subject: RE: CGS capital

When power, transmission or corporate approve a budget the specific actions still go through a captial review process. This is a capital expenditure in excess of $100 million that the agency will be on the hook to repay. We should subject it to the same rigorous review we expect of other capital allocation decisions using the standard procedures we have developed for making capital allocation decisions.

As to where we would go with this, I think it would be good to establish the precedent we review CGS capital decisions the same as other capital decisions. I'm reasonably confident the conclusion will be that the steam condenser needs to be replaced, although it would be good to know if it didn't and if not why not. The more interesting question is the choice between the two replacement options. If by chance we come to a different conclusion than ENW about which option to choose, then we we would face the question of how we pursue our conclusion.

Over the coming year or two I expect the level of scrutiny our preference customers are going to place on this decision is going to grow and they will want to know where we stand. I want us to be in a position of having performed a thorough due diligence review consistent with what we would do for a hydro or transmission investment. I also want to be in a position that if the facts change (e.g. the cost of the condenser replacement option being pursued is altered in a substantial way), that we are in a position to understand better what our reaction should be.

I am assuming it is possible to go through this review based on currently available information and therefore do not need to engage ENW unless we come to a conclusion that varies from the course ENW is on.

From: Oliver,Stephen R - PG-5
Sent: Thursday, May 08, 2008 2:24 PM
To: Wright,Stephen J - A-7; Ex 6 Rapacz,Andy - PGC-RICHLAND; Ex 6
Subject: RE: CGS capital
Importance: High

Steve;

I don't disagree that we have this option, but I would like to offer the following thoughts:

- We have spent a significant amount of time on the issue of proceeding with the condenser replacement. PGC has reviewed the Sargent & Lundy and Huron reports and have asked/answered questions (documented); and ultimately has been invited into EN meetings and briefings including the Condenser Replacement Team meetings led by Ex 6 (In fact there is one today at 3:30 PM that Andy will be attending.)
- After our internal review we've agreed with EN that we should go ahead with the replacement. We tested this with other non-EN nuclear experts at your request, and we've consistently heard that the replacement was very likely

warranted, (however the costs have been surprising to some.) We stated our support for it in the budget letter to EN last year.

- We've told EN we're past questioning it. We've told them we want to work with them to reduce costs of the task, shorten the outage, and make sure it fits in with the FCRPS operations needs as much as possible. I reiterated this to the Board of Directors just two weeks ago. We've also said this to the PPC and PRB.

Given this past course of events, I am not clear where we would go with the BPA capital review? As I understand your proposal it would be to verify the Huron analysis. If this is the objective, it might be more appropriate to hire another nuclear engineering firm to independently review both the S&L and Huron reports. Even if we took this step, we will have to manage how we explain the potential change of our position regarding our prior approval for proceeding with the project.

Thanks for continuing the dialogue on this topic.

Stephen R. Oliver
Vice President, Generation Asset Management
Bonneville Power Administration

Ex 6

From: Wright,Stephen J - A-7
Sent: Thursday, May 08, 2008 11:30 AM
To: Ex 6 Oliver,Stephen R - PG-5; Rapacz,Andy - PGC-RICHLAND; Ex 6
Subject: RE: CGS capital

We could look at it on the same basis as is in the Huron analysis done for ENW as a way of testing their analysis. That includes three options, no action, and two alternatives for steam condenser replacement.

From: Ex 6
Sent: Thursday, May 08, 2008 11:27 AM
To: Wright,Stephen J - A-7; Oliver,Stephen R - PG-5; Rapacz,Andy - PGC-RICHLAND; Ex 6
Subject: RE: CGS capital

But I thought we had made the decision.

From: Wright,Stephen J - A-7
Sent: Thursday, May 08, 2008 10:07 AM
To: Oliver,Stephen R - PG-5; Ex 6 ; Rapacz,Andy - PGC-RICHLAND; Ex 6
Subject: CGS capital

Do we think we could run the CGS steam condenser decision through our capital allocation process? It's a huge decision and it seems like it needs a due diligence determination from us. All other capital decisions go through this process.

From: Ex 6
Sent: Friday, July 11, 2008 8:23 AM
To: Oliver,Stephen R (BPA) - PG-5
Cc: Rapacz,Andy (BPA) - PGC-RICHLAND; Ex 6 Ex 6

Subject: Preliminary report to CAB on CGS condenser replacement

Steve:

As you probably know, the Agency Capital Project Review Team (ACPRT) is now reviewing the CGS condenser replacement project. Attached is a 1-page progress report that is being forwarded to CAB members today in advance of its meeting on Wednesday. No discussion is planned at this CAB meeting -- the progress report is for info purposes only.

We are scheduling time with you to review our preliminary findings (week after next).

Progress Report on ACPRT Review
CGS Condenser Replacement

The Agency Capital Project Review Team (ACPRT) is reviewing the business value of Energy Northwest (ENW)'s condenser replacement project for BPA. The review is focused on the financial implications of four alternatives that were considered in a Huron Consulting Group study commissioned last winter by ENW:

1. Titanium modular replacement installed in 2011;
2. Titanium modular replacement in 2015;
3. Titanium retube with new tubesheets in 2011; and
4. Titanium retube with new tubesheets in 2015.

The Huron Study concluded that the Titanium modular replacement – 2011 alternative was preferable because it offered greater technical and operational benefits than the titanium retube alternative and because it was financially advantageous to proceed sooner rather than later. ENW included the modular replacement – 2011 alternative in its FY 2009 budget, which the ENW Board approved and BPA non-disapproved in late spring 2008. This alternative is also reflected in the spending levels that BPA proposed in the Integrated Program Review.

The Huron Study process was largely closed to BPA and other stakeholder review until it was completed in February 2008. The Study's analytical approach, assumptions, and results were documented, however, and the Study serves as the primary source of financial data for the ACPRT's review. Huron evaluated the financial costs and benefits of the alternatives using the same life cycle costing/net present value method that Bonneville now uses to evaluate other capital projects. At the Administrator's direction, the review is being conducted with currently available materials; no request has been made for supplemental information from ENW or Huron, and no business case was requested or submitted. PGC is a full partner in the review.

We anticipate completing the review by the first week in August. Power Services will be briefed and comments considered before findings are advanced to the CAB. The ACPRT's report will cover the (1) financial and risk implications of the project alternatives and (2) a high-level assessment of ENW's capital decision practices with regards to BPA's asset strategy and standards for capital project valuation.

The ACPRT has replicated the financial analytics performed by Huron, and issues have been found that affect the calculation of net present values for the four alternatives. For example:

- The discount rate that Huron used to determine the net present value of the alternatives was 6.5 percent (reflecting ENW's weighted average cost of capital), rather than the risk-adjusted discount rate that BPA has mandated for Federal hydro and all other capital projects in Power Services.
- Incremental cash flows for each alternative were not developed by comparison to a reference, or "no action" case. All other things equal, the net effect of this is that long-term benefits were overstated
- Replacement power costs (due to lost generation) and savings were not fully accounted for, nor was replacement power cost uncertainty.

We are re-running the analytics now, and offer no findings or conclusions at this point.

From: Ex 6
Sent: Monday, August 20, 2007 1:18 PM
To: Oliver,Stephen R (BPA) - PG-5; Ex 6
Cc: Rapacz,Andy (BPA) - PGC-RICHLAND; Ex 6
Subject: FW: Delay in condenser replacement

Follow Up Flag: Follow up
Flag Status: Flagged

Steve and Ex 6

The text below is Ex 6 and my response to Steve Wright's. question. Look it over, check that it is on target, add your comments and forward it on to Steve Wright.

Thanks

Ex 6 Ex 6

Officially, we have heard nothing from Energy Northwest, which is in line with their current policy of not providing information to BPA until it is a finished product. Employees are very guarded in talking with us condenser issues. Un-officially we have determined the business case for for modular replacement has been drafted and is ready for submittal to the engineering manager. Nothing concerning this has been prepared for PHC or EAC which are the decision making committees for all large projects. Therefore no official decision has been made within EN as to which replacement type will be implemented or when. We have not been given a copy of the draft business case to review.

With regards to the outage, two items to report. First, the titanium tube replacement "pull test" failed. This means the mock-up test for mechanical connection failed and indicates the replacement of individual tubes with titanium is not a viable option. For tube replacement to be a viable option the addition of replacement tube sheets and divider plates will also have to be considered which will drastically increasing the cost and outage duration. Second, an experienced Bechtel employee Ex 6 was hired to investigate the plant configuration and determine several conceptual models for modular replacement of the condenser tubes. Rumor has it Ex 6 has determined several methods for decreasing the outage duration for modular replacement to the order of 70-75 days. The old estimate was 120 days with a confidence of a factor of two.

From the old business case provided by Energy Northwest this past spring, modular replacement with titanium tubes would have a capital cost of Ex 5 and the outage duration was estimated at 120 days vs. 68 for retubing. Note, we were informed that the outage estimate for modular replacement was considered a very rough estimate and could be off by a factor of two, and that they would need to validate this option if pursued.

From: Wright,Stephen J - A-7
Sent: Friday, August 17, 2007 6:40 PM
To: Ex 6 Oliver,Stephen R - PG-5; Rapacz,Andy - PGC-RICHLAND
Subject: Delay in condenser replacement

One thing Ex 6 and Ex 6 made a big deal about yesterday that I was not familiar with is that during the last outage they learned enough to conclude they will need to go with modular replacement and as a result the replacement will be delayed. What do we know about this?

From: Ex 6
Sent: Friday, March 16, 2007 6:32 PM
To: Ex 6 Ex 6
Cc: Rapacz,Andy (BPA) - PGC-RICHLAND
Subject: Condenser Letter Transmital to EN
Attachments: Condenser Replacement-ajr.PDF

Ex 6 Ex 6,

Please find attached an advanced copy of questions concerning the condenser replacement project. Thanks.

Ex 6

Ex 6
Bonneville Power Administration
Ex 6

Department of Energy

Bonneville Power Administration
Mail Drop 1399
P.O. Box 968
Richland, Washington 99352-0968

POWER SERVICES

March 16, 2007

In reply refer to: PGC/Richland

Mr. W. S. Oxenford, Vice President
Technical Services
Energy Northwest M/D PE04
P.O. Box 968
Richland, WA 99352-0968

Dear Mr. Oxenford:

The Bonneville Power Administration (BPA) understands that Energy Northwest (EN) has decided to replace the main condenser at Columbia Generating Station (CGS) in FY 2009 using a re-tube with titanium tubes approach. The options considered included use of various tube materials, and whether to re-tube or use modular replacement methodology. This project represents a large capital and expense impact on BPA and the region, and the condenser replacement effort itself will require an extended outage beyond the normal refueling outage length. The option that EN has selected currently requires approximately 33 additional outage days to a planned refueling and maintenance outage without condenser replacement. The cost of an additional 33 days of outage is approximately $35 million. This expense cost (not capital) will have an immediate impact on our rates that was not planned for in this 2007-2009 rate case.

BPA acknowledges EN's review of the options identified by Sargent & Lundy in their study and of the cost benefit analysis developed for those options. We would like to ensure we have clarity and a common understanding of the facts and options considered when EN reached its recommendation. With that in mind, we request that you respond to our questions below to enable us to finalize our position and take action on the condenser project, which we anticipate would occur in the course of our action regarding the FY 2008 CGS Budget.

In addition, we believe that the results of the fuel inspection and condenser eddy current testing effort, both of which are scheduled to be performed during the R-18 outage (May 2007), will provide key information regarding the need for the condenser replacement at this time. Although we would agree that the present EN recommended course of action has its merits, we would like the information requested below in order to have a collaborative discussion with you regarding whether there are timing options to condenser replacement that assure high plant reliability/integrity/safety, but are more cost effective for our regional rate payers. We would like to have this discussion prior to our action on the CGS FY 2008 Budget.

1. What is the estimated end-of-life (using the HEI methodology) for the current condenser assuming continued proper maintenance? Given the 40-year design life of the existing

condenser, and the full eddy current testing scheduled during Refueling Outage R-18, would these results (as well as the R-18 fuel inspection results) provide valuable information that either would affirm the current recommendation or indicate that the timing of the condenser replacement could be re-evaluated?

2. What are the projected costs for continuing regular refueling outage maintenance on the existing condenser, and a new condenser?

3. What is the estimated life of the new condenser, including a comparison with industry experience that supports the estimate? What is the degree of confidence the new condenser will last to the end of plant life in 2043, assuming license extension is implemented?

4. What is the expected plant energy loss due to condenser driven de-rates during summer months with a new re-tubed titanium condenser?

5. Based on industry experience, what is the projected number of tubes that will require plugging for the new condenser through end of plant life, assuming license extension is implemented, and the corresponding annual energy losses expected due to condenser driven de-rates? What is the likelihood and number of infant mortality tube failures in the new condenser?

6. What is the ability of the new condenser design to support future power up-rates, if up-rates are implemented? What are the other plant equipment upgrades and associated costs that could be implemented to mitigate power de-rates from an up-rated power level condition?

7. Please provide a summary of the number and cycle of occurrence of condenser tube failures at CGS separated into the following causal categories: debris induced, steam impingement, vibration induced, general erosion, stress corrosion cracking and others.

8. Describe the actions taken to address the root cause of foreign material exclusion (FME) problems documented in PER No. 204-0811, and how these actions are expected to prevent re-occurrence of foreign material caused leaks in the new condenser.

9. Please provide a summary of the number and cycle of occurrence of fuel failures at CGS separated into the following causal categories: foreign material induced fuel fretting, copper interaction with fuel cladding, condenser leakage (feedwater contaminants) and others.

10. Please provide the projected number of fuel failures between now and end-of-life (as estimated in question 1) of the current condenser separated into the following categories: foreign material induced fuel fretting, copper interaction with fuel cladding, condenser leakage (feedwater contaminants) and others. Also, provide the projected number of fuel failures expected during the lifetime of the new condenser separated into the same categories.

11. What are the estimated levels of feedwater copper before and after condenser tube material replacement? Will the copper levels after tube replacement meet all industry guidelines?

12. What is the estimated dose reduction relative to the collective radiation exposure (CRE) performance indicator, separated into the following categories: dose reduction due to condenser tube material replacement, dose reduction associated with chemical decontamination during refueling outages, dose reduction associated with the cobalt reduction effort and dose reduction associated with fewer tube leak repairs? What is the estimated CRE performance indicator after R-19 and after R-20 if the condenser is not replaced and the cobalt reduction efforts proceed and chemical decontaminations are conducted as part of future refueling outages?

13. Describe EN's enhanced ability to detect and repair condenser tube leaks and confirm whether this is included in the cost benefit analysis business case.

14. What is the total cost estimate to replace the condenser with the option EN has chosen, excluding the cost of replacement power? Based on the past history of cost increases in major plant projects, including ISFSI, HWC, DEH and FWH replacement, provide the degree of confidence associated with this cost estimate.

15. Please provide a copy of the cost benefit analysis business case for the condenser replacement, including a summary explaining the assumptions that were used and verified in the analysis.

16. Given a net present value of negative $65 million for the chosen replacement option, please describe the offsetting factors, i.e., regulatory commitments, INPO recommendations, etc., that make this a viable project from a cost benefit perspective. Are there any other alternative options, including condenser replacement deferral to end of life estimated in question 1, that result in a less negative, zero or positive net present value?

Thank you for addressing these important questions. If you have any questions about the list above, please contact Phil Smith at 5130 or me at 5752.

Sincerely,

Andrew J. Rapacz

Andrew J. Rapacz, Manager
Contract Generating Resources

cc:
Mr. D. K. Atkinson, Energy Northwest – M/D PE08
Mr. J. V. Parrish, Energy Northwest – M/D 1023

From: Ex 6
Sent: Friday, May 09, 2008 1:53 PM
To: Wright,Stephen J (BPA) - A-7; Ex 6 Ex 6 Ex 6 Ex 6
Cc: Oliver,Stephen R (BPA) - PG-5; Rapacz,Andy (BPA) - PGC-RICHLAND
Subject: CGS Condenser Cost Update for IPR- Worth of Lost Generation

In support of the CGS Condenser Cost Update for IPR and per Steve Oliver's direction the following information is provided:

The worth of the additional lost generation due to the condenser replacement above a normal refueling outage is estimated to be $53 million.

Notes:

- The condenser replacement will occur in spring 2011 (Apr.-Jun.)
- The latest outage length estimate is 75 days starting in early April and finishing in mid June.
- A normal refueling outage is 38 days, the condenser replacement will result in an additional 37 days of lost generation or about 983,000 MWh.
- At an average price of $54 MWh the lost generation is worth about $ 53 million in revenue.

Ex 6

ASME International

The American Society of Mechanical Engineers
Three Park Avenue
New York, NY 10016-5990

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MODULAR CONDENSER REPLACEMENT AT ANO-1 SOLVES OPERATING PROBLEMS AND IMPROVES PERFORMANCE

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ABSTRACT

After 22 years of operation, the condenser tube bundles and waterboxes at Arkansas Nuclear One, Unit 1 (ANO-1) had deteriorated significantly, impairing operating performance, reducing condenser reliability and increasing maintenance cost. An extensive condition assessment performed in 1995 revealed a 34% wall loss on the original Admiralty tubing and an erosion rate of 1. 7% annually. Additionally, Arkansas Nuclear One was considering an 8% power uprate, which would place additional duty on the main condenser. As a result, it was decided to completely reconstruct the four condenser tube bundles serving the two low-pressure turbines at Arkansas Nuclear One.

An evaluation of the available condenser tube materials was performed to determine which material was best suited for service in the single pass, single pressure condenser at ANO-1. All copper based materials were excluded from consideration due to the detrimental effect copper has on secondary chemistry and more specifically steam generator integrity. Titanium and a variety of stainless steel materials were evaluated, and ultimately titanium was selected as the replacement condenser tube material for the rebuilt condenser tube bundles due primarily to its corrosion resistance and extensive operating experience in condenser service. An impressed current cathodic protection system and epoxy waterbox coating was also installed to prevent galvanic corrosion of the carbon steel waterboxes. The cathodic protection system included local alarm indication, to alert plant operating staff of any system malfunction that could result in titanium hydriding. A . comparison of the heat transfer characteristics of the existing condenser design with Admiralty tubes and a new tube bundle design with titanium tubes concluded that a new tube bundle design was required to optimize the condenser performance and accommodate the anticipated 8% power uprate. This paper will discuss the' condenser optimization program from the design stage to final installation.

Further, it was decided to completely shop fabricate these four titanium tube bundles to minimize the site erection schedule. Each bundle measuring over 44 ft (13.5 m) long, over 13 ft (4 m) wide, and nearly 18 ft (5.5 m) tall, weighed 195,000 lbs (88,450 kg). The weight and size of the bundles created a variety of fabrication, transportation and installation challenges that required extensive advanced planning, scheduling and coordination.

The complete installation of the redesigned condenser tube bundles and waterboxes was accomplished during the Fourteenth Refueling Outage of ANO-1 in 1997.

INTRODUCTION

Arkansas Nuclear One, Unit 1 (ANO-1), an 883 Mwe PWR, was licensed for commercial operation in 1974. The original Westinghouse turbine/condenser system consisted of a single-pressure, dual exhaust LP turbine exhausting to two, single pressure, single pass surface condensers.

A condition assessment of the original condenser was performed in 1995 which revealed the condenser had experienced several types of tube degradation during the 22 years of previous service. The failure mechanisms present in the ,condenser included: uniform ID erosion, steam impingement, ammonia grooving, intergranular corrosion, vibration damage, circumferential cracking, localized cor' osion, ID pitting, and mechanical damage. The most significant of these was the circumferential cracking at or near mid-span between support plates. The primary cause for this condition was increased tube vibration due to uniform ID erosion. During this condition

assessment, the average wall loss of the condenser tubes was measured to be 34% less than the originally supplied tube wall thickness. Even more significant, the erosion rate was estimated to be 1.7% annually.

In addition, copper deposition throughout the secondary system from the Admiralty condenser tubing was detrimental to the integrity of the steam generator tubing. Also, the secondary chemistry pH suitable for the Admiralty tubing resulted in higher secondary corrosion rates and more iron transport to the steam generators. Finally, the adverse effects of circulating water contamination was a threat to secondary chemistry limitation and damaging to the steam generators.

After an exhaustive evaluation of all viable alternatives, it was decided that the existing Admiralty condenser tubes and Muntz tubesheets should be replaced with a new tube bundle design utilizing titanium tubes and tubesheets. This evaluation considered numerous other non-copper alloys ranging from 316L stainless steel to AL6XN. The primary factors used to evaluate each material were material compatibility with the site's brackish cooling water, initial and future maintenance costs, plant performance, industry operating experience and probable failure modes (corrosion, under deposit pitting, biological fouling, etc.). It was further determined that this replacement would be accomplished using shop fabricated tube bundles and waterboxes to minimize required installation time. Each tube bundle was to be completely shop assembled and thoroughly tested before being shipped to ANO-1 for installation. In addition to compensating for the difference in the thermal conductivity between Admiralty and Titanium, the replacement condenser design was required to optimize condenser performance at the contemplated 8% power uprate condenser duty. Refer to Table 1 for comparative performance requirements.

Also, the physical size and weight of the tube bundles presented the project with many transportation and installation challenges. These challenges necessitated an extraordinary level of coordination between the various entities involved in this condenser tube bundle and waterbox replacement project. The limited installation window available with the scheduled refueling outage further enhanced this level of coordination.

MODULAR TITANIUM BUNDLE DESIGN

The design optimization program had to consider the required 8-pereant power uprate utilizing the existing dreulating water system while producing an *efficient* turbine output The difference between the hestYtransibr coefficients of the original Admiralty tubing and the new rolled/welded I inch (25. mm) diameter, 24 BWG and 22 BWG titanium tubing (ASTM B338, Or. 2) provided a significant challenge in the design of the new condenser bundles.

With the external envelope of the condenser intact, the condenser design optimization had to consider several key elements. Assessment of the existing circulating water pump capacity against condenser backpressure with the new bundle design was of utmost importance. Multiple cases of thermal/hydraulic design combinations were analyzed balancing the circulating water system, optimizing pumping efficiency, cooling water usage, MW output, and hardware cost. Evaluation of the space constraints within the existing condenser provided the final interface requirements with the new modules. Spacing of the new support plates was reduced considerably with the lighter gauge titanium tubing in order to alleviate tube vibration during full load operation with one bundle out of service.

New condenser waterboxes were designed to facilitate installation, improve flow distribution to the tubes, and minimize pressure drop. This was the critical interface piece between the new condenser bundles and the existing circulating water piping in the plant A sophisticated Finite Element Analysis program verified the structural integrity of the new waterboxes, and subsequent shop hydrostatic testing confirmed the results. Waterboxes were equipped with an impressed current cathodic protection system and internal epoxy coating to prevent galvanic corrosion of the carbon steel surfaces.

The new titanium tube bundles were more erosion resistant, with better deaeration capabilities. However, their lighter weight in spite of a more compact tube field necessitated a thorough uplift analysis to evaluate the integrity of the existing anchor bolts and the necessity for additional anchoring.

The condenser bundles were fabricated to high quality standards in a controlled shop environment Several shop mock up tests were performed to determine the optimum tube pull out load, and the required wall reduction for the rolled tubes. Prior to rolling and welding, 100% base line eddy current testing of the tube bundles was completed. Results of this test were stored on several tapes and were submitted to ANO. Future in service eddy current examination can be made and compared to base line results to determine wear.

All tube ends were rolled and welded using automatic welding machines. Tube welds were checked for integrity using dye penetrant testing, and also vacuum leak testing to verify the integrity of the tube joints and the entire tube length. Once pronounced sound, condenser modules were wrapped in specially designed tarps and shipped to the site.

Figure 1 details the overall size and weight of one of the four replacement condenser tube modules, and Figures 2, 3, and 4, show the bundle manufacturing process at several stages.

BUNDLE TRANSPORTATION

With the massive size and heavy weight of each titanium tube bundle, transportation logistics became a significant issue.

The Departments of Transportation in several states had to be contacted to assure that roads, highways, and bridges would be available for this transport Special permits and full time escorts were required from the manufacturing plant to the job site to assure safety and security of all involved. Limited height was a critical element throughout the transportation route. Rail transportation was out of the question due to oversize weight and dimensions, and truck transportation was the most viable alternative at the time of shipment Figure 5 shows how the trunnions welded into the bundles were supported by the longitudinal "r beams, and Figure 6 shows the special trailer arrangement developed for this transport purpose. Essentially it could be celled a "double-pole" trailer where two specially designed "r beams almost 15-f (4.6m) apart supported the tube bundle suspended between them. The special trunnions supported the tube bundle, reducing its overall height above the road as much as possible. Since only one such special trailer was built, it had to make four round trips from the manufacturing facility to ANO to complete the delivery project. Waterboxes were shipped separately to maintain the overall schedule and to keep bundle transportation within allowable size and weight limitations.

PROJECT INSTALLATION

The installation phase of the condenser tube bundle and waterbox replacement project presented numerous challenges for the project team.

The first challenge was completing the condenser replacement within the scheduled refueling outage duration of 42 days and 1 hour. This limitation affected every decision made on the project from the beginning of the project.

The second challenge was the physical location of the condenser, which was 19 feet below ground level. The only existing access to the area was through a condenser tube pull pit, which was approximately 10 feet shorter than the condenser tube bundles. To provide access to the existing condenser shells, a large opening was made in the side of the turbine building, which included the removal of structural steel, interference piping and electrical interferences. Figure 7 shows the bundle transportation at the site, and the available access route to the condenser portal. Figures 8 and 9 shows the opening in the turbine building wall and the elevation of the existing condenser shells relative to ground level. Figure 10 shows insertion of one of the tube bundles into the turbine building.

The third challenge was the proximity location of several interferences outside the turbine building which greatly restricted access to the condenser area. These interferences include the main transformers and startup transformer #2 and associated electrical buss ducts and 500 KV and 261 KV overhead power lines (Fig. 7). These interferences precluded the use of a large crane to rig the tube bundles into the tube pull pit. A specially designed gantry crane capable of lifting, translating and rotating each tube bundle was designed and assembled over the tube pull pit (Fig. 9). The gantry included a specially designed lift frame that allowed the load to be shifted while still suspended to locate center of gravity and ensure that the tube bundles were kept level during the rigging operation. The gantry also included a hydraulic turntable for better control of the tube bundles while the bundles were rotated.

The fourth major challenge was the limited access to the condenser inside the turbine building. To get the new tube bundles and waterboxes into . the condenser, a large track was assembled in the turbine building basement and extending into the condenser shell (Fig. 8). Specially designed hydraulically powered rollers were used in a load equalizing arrangement to ensure that each roller shared 25% of the total.bundle load and to prevent damage to the tube bundles. Also, specially designed carts were fabricated to allow the replacement waterboxes to be moved into position through the condenser shell using the rigging assembly available in the condenser hotwell.

The fifth challenge was the removal of the existing condenser tube bundles and waterboxes. After an extensive evaluation of all available alternatives, it was decided that the existing condenser tube bundles would be cut in half inside the condenser shell and removed with waterbox attached. However, to move the tube bundle halves with waterbox attached, each bundle would have to be stiffened to allow the bundle to be both rolled out of the condenser shell using the hydraulic rollers and lifted out of the tube pull pit with the gantry crane.

The final challenge was estimating, planning, scheduling and managing the resources and manpower required to complete a construction project of this size with the available refueling outage window.

CONCLUSION

The ANO-1 Condenser Project was successful in all phases of the project including: initial condition assessment, project feasibility study, competitive bid process, condenser re-design, shop fabrication, bundle transportation and field installation. The complete installation of the redesigned condenser tube bundles and waterboxes was accomplished during the Fourteenth Refueling Outage of ANO-1. The duration of the refueling outage was 43 Days and 15 Hours. The Circulating Water Outage required for the condenser replacement was 33 Days and 21 Hours. Although a full ASME PTC 12.2 performance test was not completed following the condenser tube bundle replacement, the condenser backpressure for the redesigned condenser was measured using plant instrumentation and the results indicated an improvement of 0.19 inHg to 0.23 inHg when compared to the backpressure of the original condenser at the same circulating water temperature and condenser duty. To date, the replacement condenser tube bundles have not experienced any in-service tube leaks and unit has been operating reliably and efficiently.

REFERENCES

- Kurtz, S.A., Ward, R.L., Schuunerth, D.J., A Titanium Tubed Modular Condenser Changeout at the Ravenswood Generating Station, PWR — Vol. 12, Performance Monitoring and Replacement of Heat Exchanger Components and Materials, American Society of Mechanical Engineers, 1990.
- Heat Exchange Institute (HEI) Standards for Steam Surface Condensers, Eight Edition - Addendum 1.

EPRI CS-3914 — Biofouling Detection Monitoring Devices — March 1985

- EPRI CS-3844 — Condenser Procurement Guidelines — May 1985.
- EPRI CS-3200 — High Reliability Condenser Study — July 1983.

EPRI NP-2371 — Condenser Retubing Criteria Manual — May 1982.

Table 1
Comparative Performance Requirements and Configuration

	Existing	Required*
Condenser heat load – total Btu/hr.	5.711×10^9	6.150×10^9
Number of condenser shells	2	2
Number of tube bundles per shell	2	2
Number of waterboxes per shell	4	4
Number of tubes per condenser shell	19,608	24,974
Surface area per condenser shell – ft^2	254,000	287,825
Tube material	Admiralty	Titanium
Tube Diameter – in.	1.125	1.00
Tube gauge (condensing section) – BWG	18	24
Tube gauge (peripheral impingement section) –BWG	n/a	22
Design circulating water flow rate – total gpm	764,000	782,200
Average tube circulating water velocity – ft/s	7.52	7.00

(*) Required operating parameters after the contemplated 8-percent power uprating

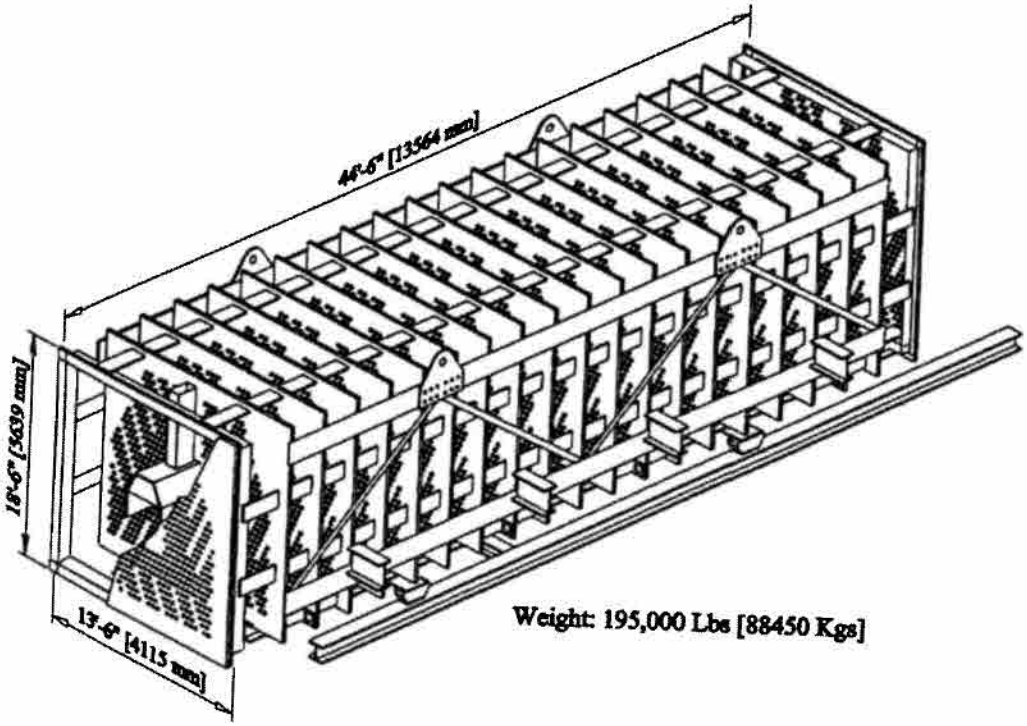

Figure 1
Condenser module arrangement

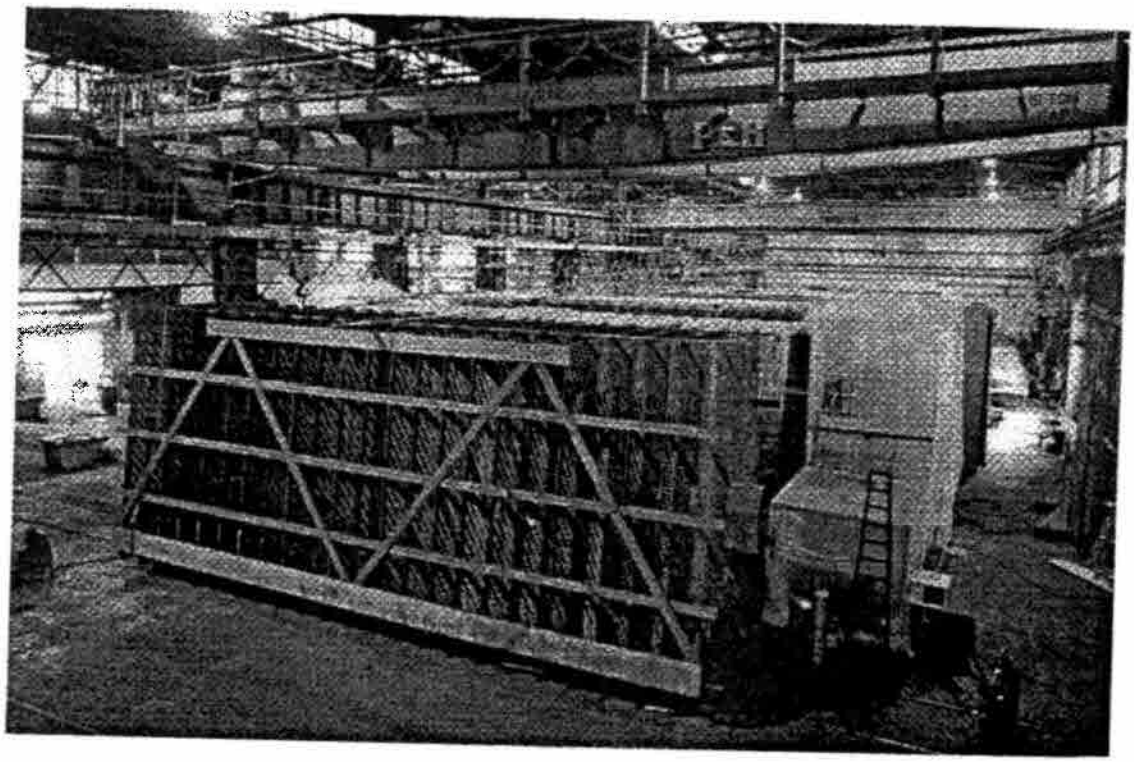

Figure 2
Bundle fabrication and tube welding clean house assembly

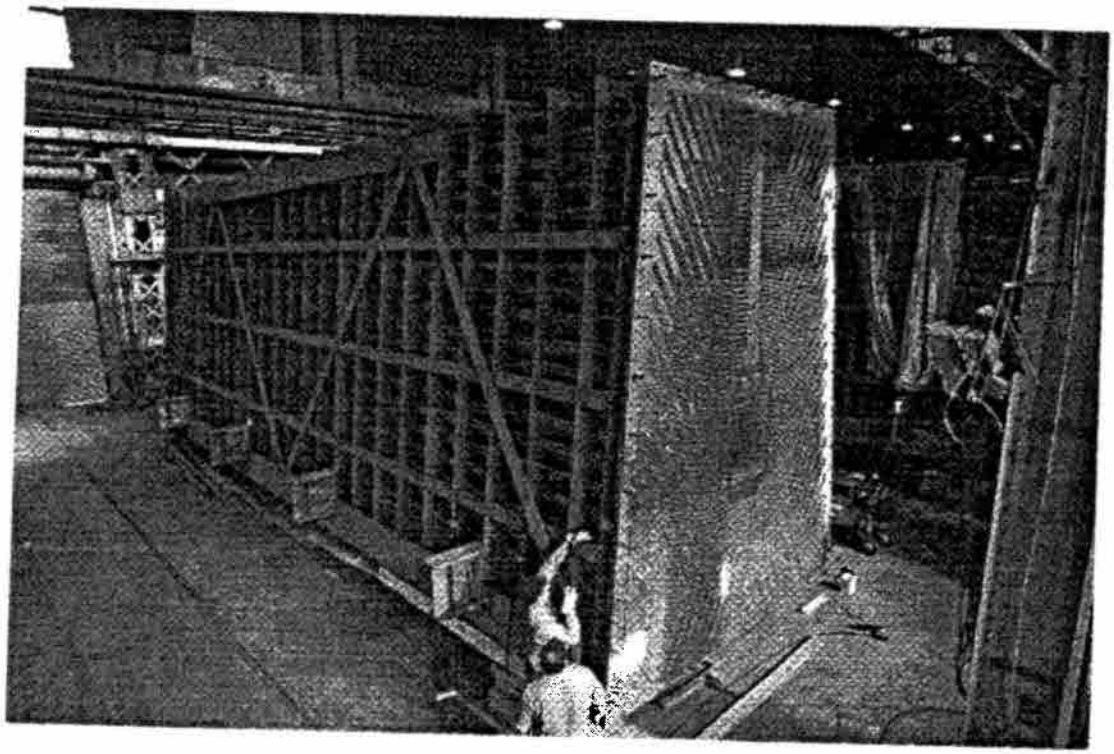

Figure 3
Bundle inspection prior to shipment

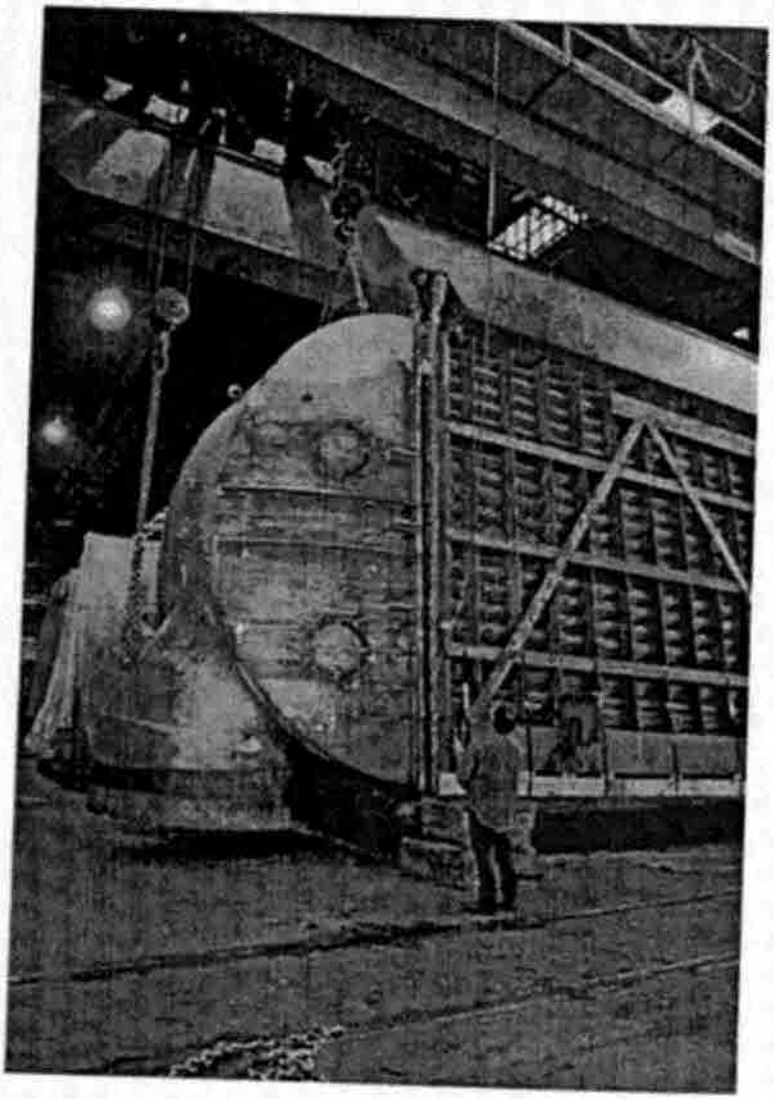

Figure 4
Waterbox fit up in the factory

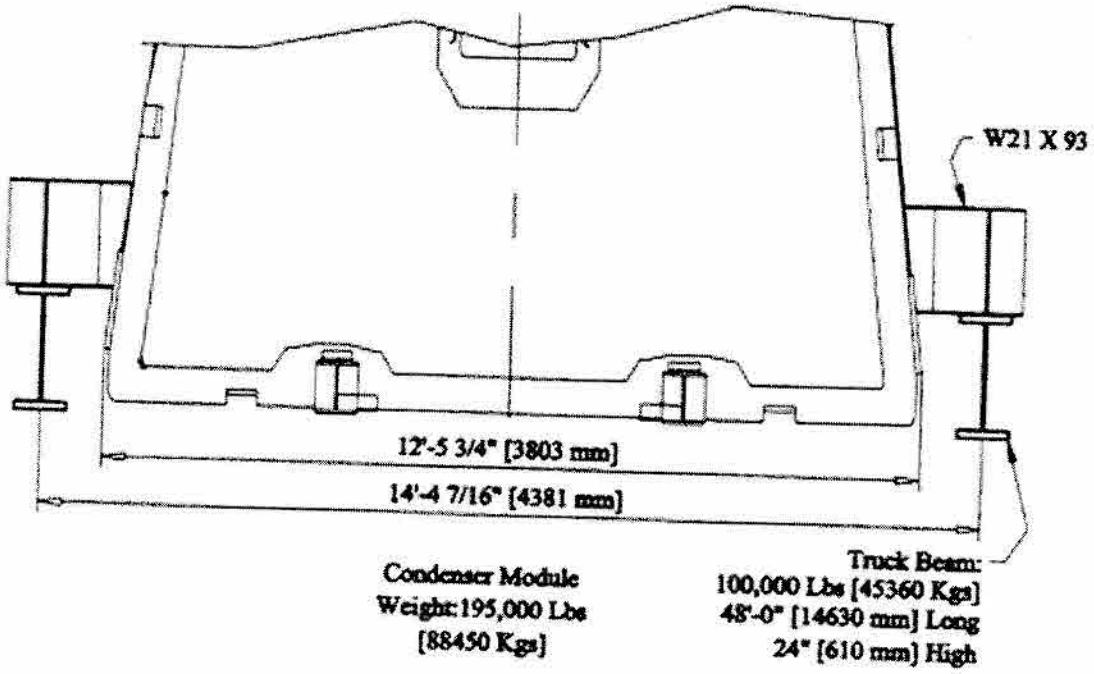

Figure 5
Truck beam arrangement

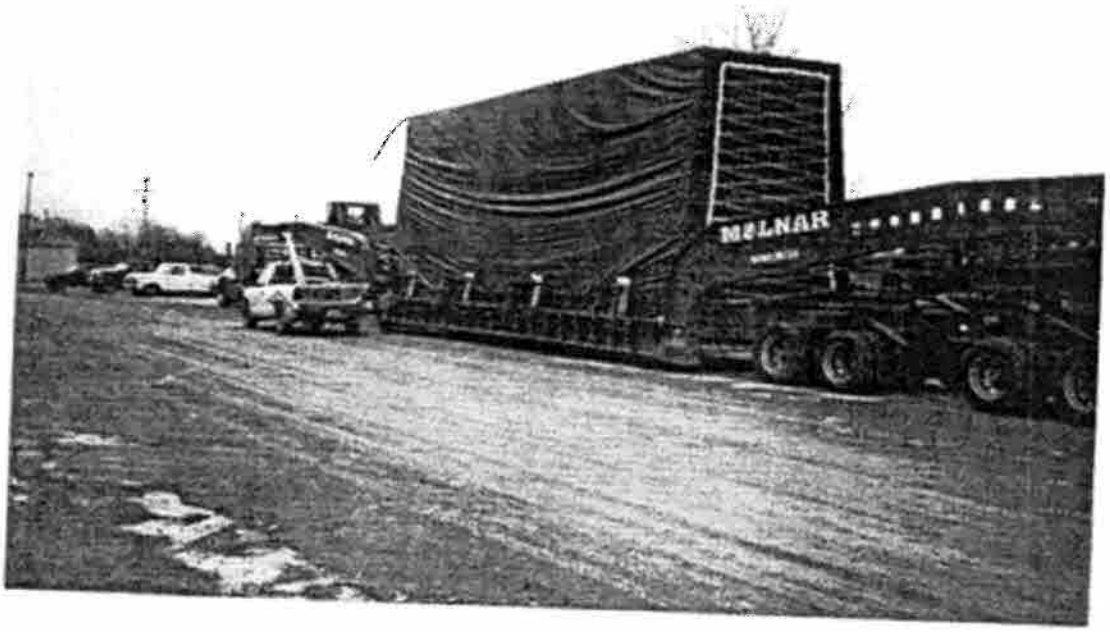

Figure 6
Bundle transportation from factory

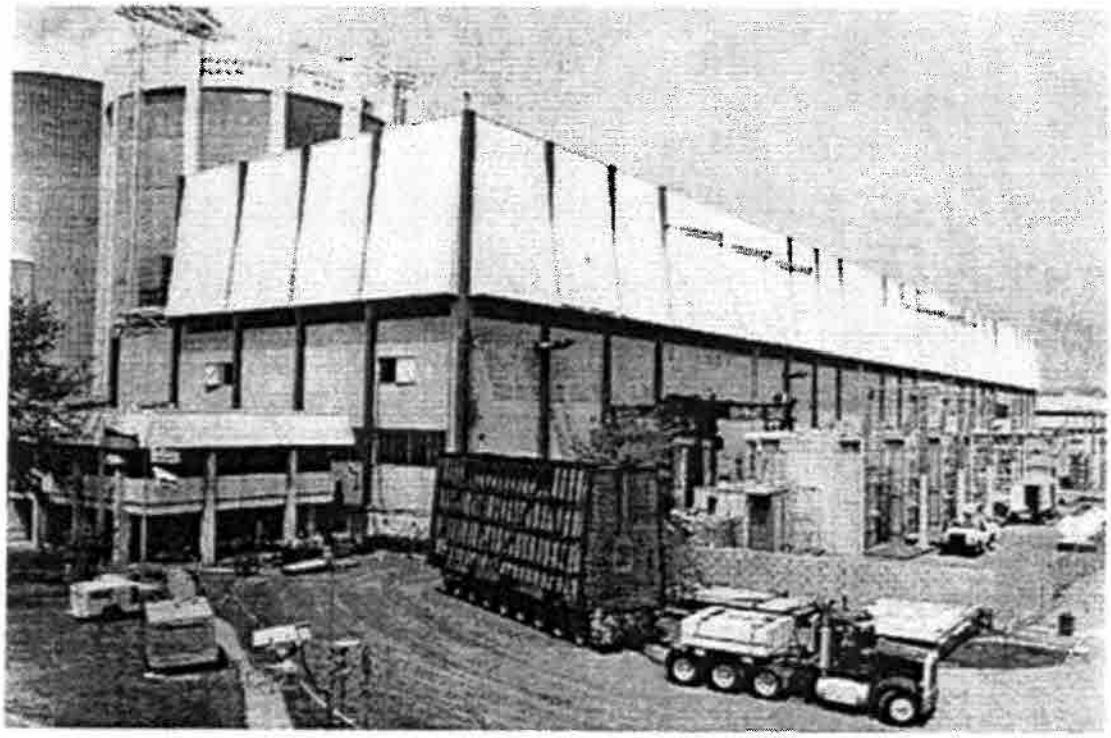

Figure 7
Bundle transportation at the site

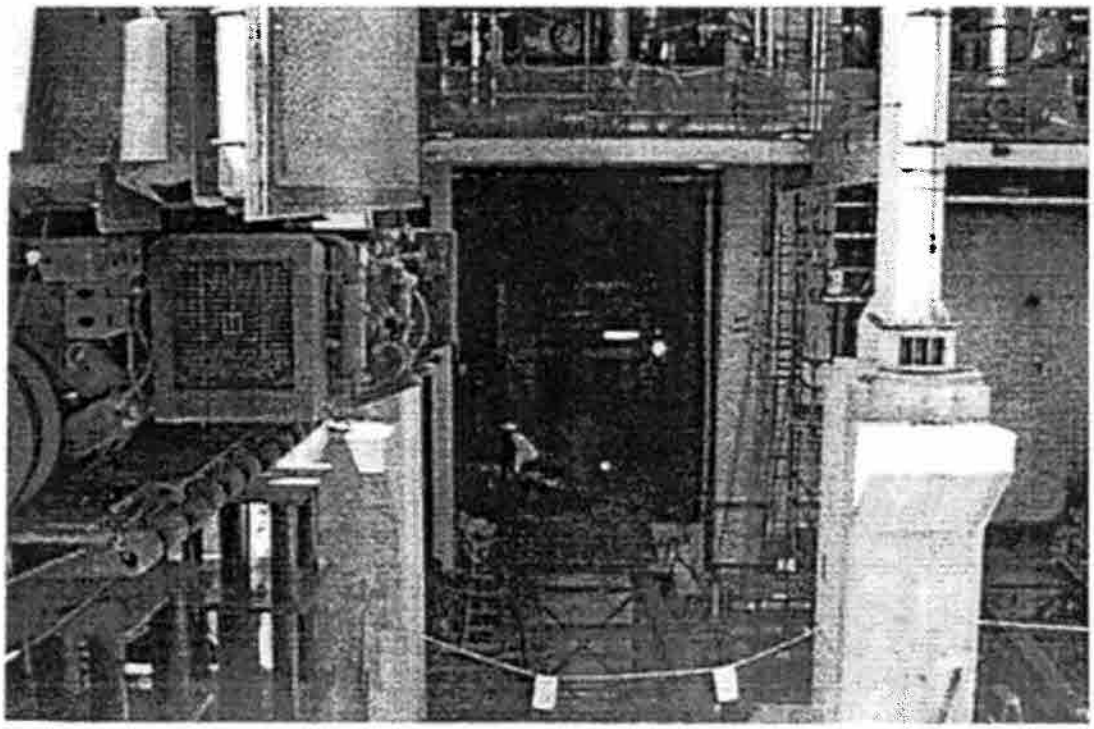

Figure 8
Opening in the turbine building wall

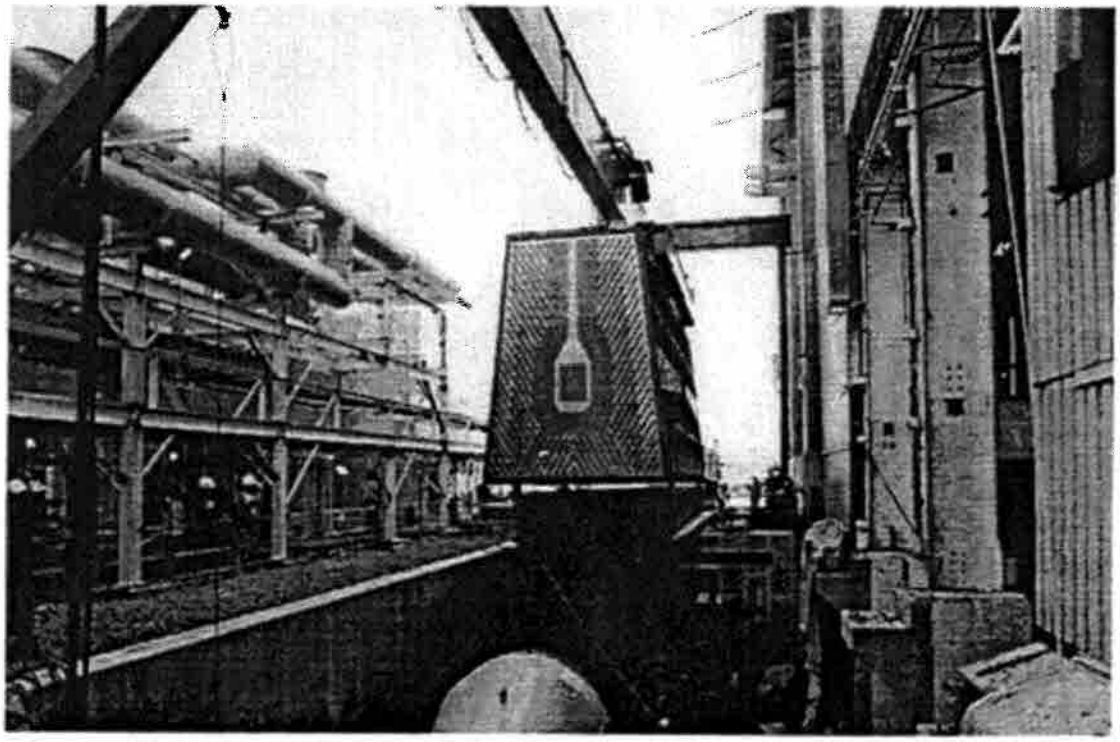

Figure 9
Condenser bundle at ground elevation above the tube pull pit area

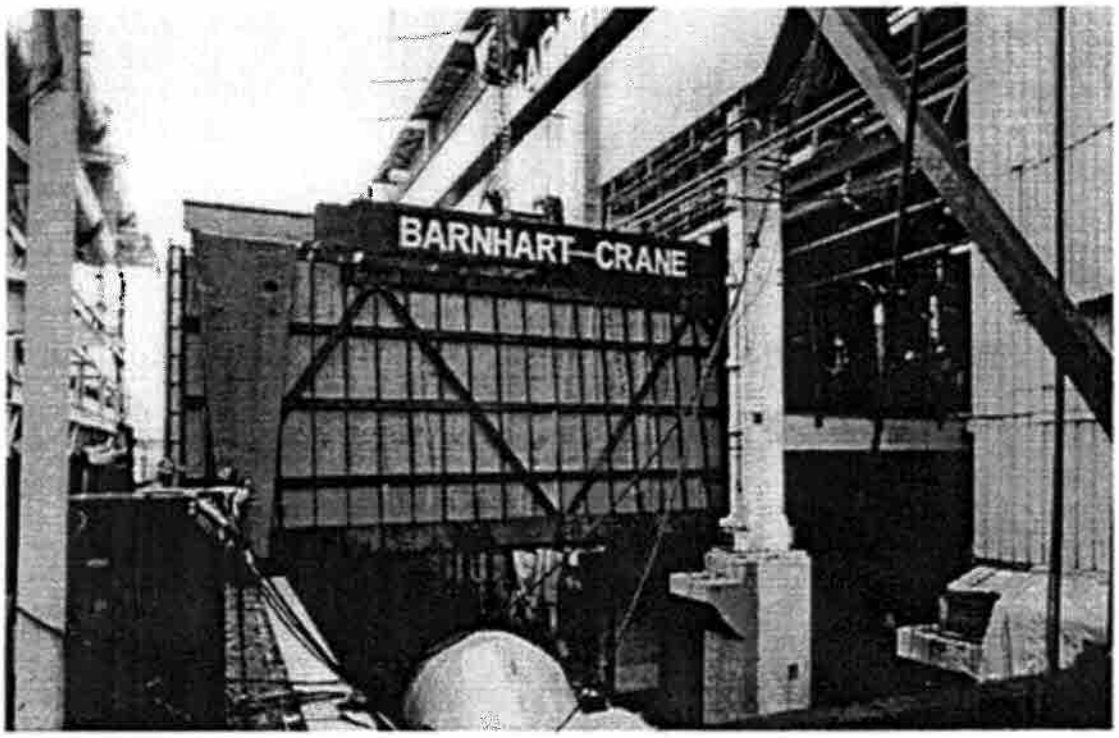

Figure 10
Bundle insertion into the turbine building

CGS Condenser Replacement Update

The tube bundle modules (Modules) and the water boxes on the main condenser will be replaced during the 78 day spring 2011 outage which is scheduled to start on April 6, 2011.

All twelve condenser modules and associated water boxes have arrived on site along with 12 shipments of field weld pieces

Design Work: Engineering designs from B&W (the installation contractor) for module bracing, shell stiffening, rigging/supports have not yet been completed and is impacting completion of the remaining work order planning. The Project team is continuing to work with B&W to expedite completion of this work.

There will be a couple of planned Field Change Requests issued during the outage to document as built condition of several piping runs that must be field run to deal with anticipated interference problems.

Work Orders: Work order preparation met the outage mile stone of having 98% of the work orders planned. The next goal is to complete walk-downs of the tasks on the work orders. This goal will not be met by the January 13, 2011 milestone. The Project team and B&W are working extended hours to complete all of the walk downs as quickly as possible while maintaining quality. The Project is working on a revised walk down completion date to provide to Outage management.

Readiness Review: Ex 6 completed his readiness review and submitted his final report that has been forward to BPA and EN senior management. Ex 6 had three recommendations based on his outage readiness review, of the three recommendations made, only one applied directly to the condenser project. Ex 6 executive summary concludes the condenser replacement project appears to be well managed and is following the recent guidance provided by INPO on nuclear project management.

Cost Estimate: Budget for the current fiscal year (FY11) is currently at $42.2M. This estimate includes changes to temporary access point (TAP) made necessary by security regulations.

B&W has informed the Project of a scope increase/cost impact from the original design (revision 0), that the installation contract was bid on; to the current design (revision 6) supplied by SPX the module designer. The Project team is working with B&W to determine the impact and expect to have an estimate from B&W by the end of January.

Issues:

1. Completing the work order walk downs. The Project is working on a new completion date.

2. The 96" Circulating Water isolation valves contingency repair plan is a project risk that is not yet fully funded. It is expect that two of the six Circulation Water isolation valves for the condenser will require repairs. Parts have been ordered but funding for the contingency work has not yet been identified so a contract can not be awarded for the work.

3. TAP design is done for phase 2 of Site access but completing the installation by the February 28, 2011 goal will be challenging.

4. B&W claims for increase scope from the original revision 0 design.

BPA Perspective: Overall, EN has adequate controls in place to successfully manage this project to completion. This view was confirmed by Ex 6 in his review.

CGS Condenser Replacement Update

The tube bundle modules (Modules) and the water boxes on the main condenser will be replaced during the 78 day spring 2011 outage which is scheduled to start on April 6, 2011.

All twelve condenser modules have arrived on site. Eddy Current testing of the modules identified two tubes needing to be replaced due to damage that occurred either in packing or shipment. Several tubes could not be tested due to interferences at the tube sheet opening that would not allow the Eddy Current probe to be inserted into the tube. Energy Northwest will have the module fabricator correct these problems on site prior to installation.

The water boxes are scheduled to be on site by mid November.

Design Work: Completion of engineering design work has progressed to the point where it is no longer a challenge to the project. There will be a couple of planned Field Change Requests issued during the outage to document as built condition of several piping runs that must be field run to deal with anticipated interference problems.

Work Orders: Work order preparation met the outage mile stone of having 98% of the work orders planned. The next goal is to complete walk-downs of the tasks on the work orders.

Readiness Review: EN is planning to conduct a readiness review of the condenser project on the morning of October 28th. Due to scheduling conflicts, Dave Oatley will unable to attend but PGC staff will participate in the review. We are planning to work with Dave Oately to set up a time in November or early December for him to do an independent review of the project readiness.

Cost Estimate: Budget for the current fiscal year (FY11) is $40.9M. Total project costs (FYs 08 -12) are estimated at $113.4M, an increase of about $6.1M over the original business case done February of 2008. These estimates do not include changes to temporary access point mentioned below that could increase the project costs by $1M.

Issues: Site access, due to the number of craftsmen scheduled to work on the condenser during the outage, the Plant's existing primary security access point would be over loaded and would have difficulty in processing the condenser project personnel, in addition to all the regular outage personnel, into the Plant every morning and each afternoon following their noontime lunch break. The over crowding would cause delays in getting personnel to their work locations inside the protected area, thus impacting the refueling outage costs and length. As a solution to this problem a second, temporary access point was planned; however, the costs of this second access point have increased dramatically as the most recent NRC mandated security rules require the same level of surveillance equipment as the primary access point. Originally the plan was to use extra security personnel to meet these requirements but it has been determined that this approach will not meet the NRC mandated requirements. The Plant staff is preparing an estimate of the costs to meet the NRC requirements and is rerunning the business case to determine if it is still cost effective to use a temporary secondary access point during the outage.

BPA Perspective: Overall EN has adequate controls in place to successfully manage this project to completion. EN is planning to conduct independent readiness reviews along with the installation contractor.

CGS Condenser Replacement Update

The tube bundle modules (Modules) and the water boxes on the main condenser will be replaced during the 78 day spring 2011 outage which is scheduled to start on April 6, 2011.

Four of the twelve Modules are on site; five more are packaged and ready to be shipped. All twelve Modules are expected to be on site by mid August. The Modules were inspected at the fabrication facility prior to being packaged for shipment but after arrival on site each of the Modules will be "Eddy Current" tested for indications of leaks or damage incurred during shipping.

The water boxes are scheduled to be on site by the end of October.

The installation contractor has had key management people on site since January working on their mobilization plan, QA plan, Safety Plan, Rigging Plan, schedule, qualification of their work documents and welding program.

Design Work: Completion of the engineering design work continues to be the biggest challenge to the project. There are 13 heater drain lines that are required to be rerouted as part of the Module replacement. Completion of the design and pipe stress analysis has been running behind schedule. EN has taken corrective actions and the design packages are now expected to be completed by engineering in July.

The Plant staff is considering the formation of an Engineering team that will be available to address field change requests and other design issues that will come up during the actual field installation in the outage. Engineering resources need to be available to support prompt resolution and keep the work going in the field. The ability to stay on schedule and successful completion of the installation will be impacted by the ability to resolve design issues during the outage.

Work Orders: Work order preparation is behind schedule because the engineering design has not been completed as mentioned above. If the engineering designs are completed per the recovery plan, the milestone of having 98% of the work orders planned by October is still achievable.

Readiness Review: EN is planning to conduct a readiness review later this summer or early fall to check the project's status and preparedness to perform during the spring refueling outage. PGC has asked Ex 6 to conduct a readiness review and are having discussions with him regarding participation directly in the EN review process or to review EN's report for completeness and conclusions and then provide his own insights.

Cost Estimate: Budget for the current fiscal year FY11 is $40.9M. Total project costs (FYs 08 - 12) are estimated at $113.4M, an increase of about $6.1M over the original business case done February of 2008.

BPA Perspective: Overall EN has adequate controls in place to successfully manage this project to completion.

Issues: None

MARSH MUNDORF PRATT SULLIVAN & McKENZIE
ATTORNEYS AT LAW • A PROFESSIONAL SERVICE CORPORATION

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May 9, 2006

Paul E. Norman
Senior Vice-President, Power Business Line
Bonneville Power Administration
c/o Public Affairs Office – DKC - 7
P.O. Box 14428
Portland, OR 97293-4428

Re: Clarification of the Comments of the Western Public Agencies Group On BPA's Power Function Review II Draft Close-out Letter

Dear Mr. Norman:

On April 26, 2006, the Western Public Agencies Group (WPAG) provided comments on your draft close-out letter of April 4th, 2006, for Phase II of the Power Function Review (PFR II). We would like to clarify the remarks contained in section 2 of those comments.

The WPAG utilities have urged BPA to carefully scrutinize all costs that go into its rates, whether they are Corps, Bureau, Energy Northwest or BPA's internal costs. Consistent with that approach, section 2 of the WPAG comments suggested that the budget item for the ENW condenser replacement receive a similar review.

Since the WPAG comments were submitted, we have received additional information on this item from ENW. Based on that information, the WPAG utilities are persuaded that this budget item has been substantiated in the amount and with the timing proposed.

The WPAG utilities felt it was important that you receive this information as promptly as possible. This is an instance where the PFR II process has worked as it should – a question was raised, and a fully responsive answer was timely provided.

(over)

Yours truly,

/S/ Terence L. Mundorf

Terence L. Mundorf
Attorney for the Western Public
Agencies Group

Department of Energy

Bonneville Power Administration
Mail Drop 1399
P.O. Box 968
Richland, Washington 99352-0968

POWER SERVICES

January 23, 2009

In reply refer to: PGC/Richland

Mr. S. K. Gambhir, Vice President
Technical Services
Energy Northwest M/D PE04
P. O. Box 968
Richland, WA 99352-0968

Dear Mr. Gambhir:

In reference to your letter "Energy Northwest Agreement 327447 Main Condenser Replacement Modules," dated January 20, 2009, and received on January 21, 2009, the Bonneville Power Administration does not disapprove the execution of the proposed contract action.

The proposed action would authorize Energy Northwest to execute a contract as a result of RFP 651803, with Yuba Heat transfer in an amount not to exceed $34,660,000 for the design, manufacture and delivery of twelve condenser modules in support of the main condenser replacement project which is planned for execution during the R-20 refueling outage. BPA notes that this non-disapproval superceeds the non-disapproval provided to you in our November 10, 2008 letter.

Sincerely,

Andrew J. Rapacz, Manager
Contract Generating Resources

cc:
Mr. Brian G. Berglin, Energy Northwest - 964F
Ms. Lynne A. Pagel, Energy Northwest - PE10

bcc:
Official File – PGC (PM-14-23) (Columbia)
ERMS: http://bpaweb/services/erms/PM/14/23/PGC%20Records/Forms/AllItems.aspx

Ex 6 :1/23/09 (W:\Office\Briefing Papers\CY 2009 papers\a 1089 Main Condenser Module Fabrication Yuba bb.doc)

BONNEVILLE POWER ADMINISTRATION
CONTRACT GENERATING RESOURCES (PGC)
Briefing Paper, Columbia Generating Station (CGS)
Action Memorandum No. 1089
CGS Main Condenser Replacement Modules

REFERENCES: 1) Energy Northwest letter to A. J. Rapacz, "Energy Northwest Agreement 327447 Main Condenser Replacement Modules," dated January 20, 2009, and received on January 21, 2009. This letter supersedes EN's previous condenser module award letter, Energy Northwest letter to A. J. Rapacz, "Energy Northwest RFP 651803 Main Condenser Replacement Modules," dated October 23, 2008, and received on November 7, 2008.

2) PGC briefing Paper for Energy Northwest letter to A. J. Rapacz, "Energy Northwest Agreement 319873 Contract Release 28 Main Condenser Project Design Support," dated March 24, 2008, and received on April 1, 2008.

3) PGC briefing Paper for Energy Northwest letter to A. J. Rapacz, "Energy Northwest Agreement 326930 Main Condenser Project Design Support," dated August 27, 2008, and received on September 8, 2008.

CONTRACT: Energy Northwest Action Memorandum No. 1089 Columbia Generating Station Main Condenser Replacement Modules to Yuba heat Transfer (Yuba).

ACTION TOPIC: Energy Northwest (EN) has requested BPA's non-disapproval for execution of Action Memorandum 1089 for RFP 651803 Main Condenser Replacement Modules, to Yuba in an amount not to exceed $34,660,000 for design, manufacture and delivery of twelve main condenser modules in support of the Main Condenser Replacement Project. Replacement of the main condenser is planned for execution during the R-20 refueling outage (FY 2011).

DISCUSSION: **Background** - The main condenser is a critical component and is required for operation of CGS. Sustained poor maintenance and inadequate foreign material exclusion control has created a situation of condenser tube failures resulting in unplanned plant down powers for tube leak repairs and additional costs for inspections and tube plugging. EN's technical staff estimates the end of useful life of the current main condenser is 2018. Additional concerns are related to high levels of copper (Admiralty Brass) contained in the current condenser tube material which challenge reliable operation and minimization of radiation dose to employees. Reliable operation of this system is a high priority for EN. The maintenance and repairs performed during the last refueling outage (R-18) have proven effective with no power reductions necessary since the R-18 outage. EN does anticipate however, that new tube leaks will develop at some point in the future. With the extensive tube plugging in R-18, it is hoped that CGS can run until R-19 with minimal leaks. CGS is currently operating with a very small leak resulting in additional resin costs to maintain reactor chemistry. As stated by the EN VP of Technical Services at the March 2008 Board of Directors meeting, the continued operation of the main condenser is not a nuclear safety issue.

Work Scope - The Main Condenser Replacement Project has been broken down into two principal segments based on the two main requests for proposal (RFP): 1) contracts associated with RFP 651803 for design, fabrication and delivery to the site of replacement condenser modules, and 2) contracts associated with RFP 651804 for performance of tasks necessary for the removal of the existing condenser modules and installation of the new replacement condenser modules. The contract that will result from execution of this Action Memorandum is part of a larger overall effort executed as a phased approach to replace the main condenser tubing and supports with pre-fabricated titanium modular bundles. The phased approach is described in more detail in Reference 2. Reference 3 documents the engineering services for condenser performance monitoring instrumentation and is included here for completeness only.

The purpose of this contract is to provide design engineering services, manufacturing and delivery of 12 main condenser replacement modules to be installed during the R-20 refueling outage. Additional requirements are in accordance with Procurement Specification 12502, and the successful bidder is to coordinate work with EN and EN's installation contractor(s) performing the project management, engineering and installation of the condenser modules.

Procurement Process - The competitive negotiation process was used with RFP 651803, which was first issued on May 23, 2008. Responsive proposals were received August 6, 2008, from Westinghouse (Toshiba), Yuba Heat Transfer (Yuba), and Thermal Engineering International (TEI). Following vendor discussions and plant visits with all three companies, a request for Best and Final Offers (BAFO) was issued on September 29, 2008. The BAFOs were received from all three vendors on October 9, 2008. The proposal evaluation included eight technical and two commercial criteria. The eight technical criteria are summarized as follows: response to procurement specifications and work requirements completeness; relevant experience; team composition and qualifications and experience; fabrication capability and capacity; guaranteed performance; consideration of schedule; technical alignment with EN and project ownership; and overall technical adequacy of the proposal including likelihood of meeting the July 7, 2010 delivery date. The two commercial criteria included acceptance of terms and conditions, and cost.

The contract is a fixed price contract having liquidated damages for late module delivery and provisions for performance payment adjustments for increased/decreased condenser performance. The contract costs include a fixed price element and allowances for cost reimbursement elements such as performance bond and transportation costs.

Final Award – Originally a vendor other than Yuba was selected as being the most technically advantageous and representing the lowest cost to EN. However, during negotiations for finalizing the contract, the original vendor could not answer a number of technical questions to EN's satisfaction, including an evaluation of the economic benefit of using smaller diameter tubes to improve the thermal efficiency of the condenser. At this point EN begin discussions with Yuba, the second ranked bidder to confirm they could provide the technical bases and manufacturing capability to meet the design and fabrication requirements to support the condenser replacement project. Yuba's fixed bid of $34,660,000 is comparable with that of the original contract award.

FUNDING: Funding for a portion this contract is included in the approved FY 2009 Budget. The remaining funding will be provided in fiscal years 2010 and 2011 per the EN approved long range plan.

ISSUES: None with this action.

ACTION: BPA agrees replacing the main condenser tubing will improve the system reliability and significantly addresses reliability concerns. PGC staff will prepare a letter of non-disapproval for the awarding of this contract to Yuba, superseding the previous non-disapproval letter.

bcc: Official File – PGC (PM-14-23) (Columbia)
ERMS: http://bpaweb/services/erms/PM/14/23/PGC%20Records/Forms/AllItems.aspx

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Reviewed: _____ BB / date

AJR 1/23/09
AJR / date

BPA list for Condenser replacement success:

- Condenser critical path schedule reduced from the current 87 days
- Replacement itself completed within schedule
- completed within estimated budget
- obtain all expected increase in electrical output (this is what makes the modular replacement a viable option with a positive NPV)
- no more than one condenser leak for the next 5 cycles
- improved off-gas system performance over the existing system
- personnel safety goals for the Project are met (goals to be established)
- No adverse consequences to other systems in the Plant

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

FREEDOM OF INFORMATION ACT/PRIVACY PROGRAM

May 19, 2014

In reply refer to: D-B1

Paul Koberstein
Cascadia Times
4037 N. Overlook Terrace
Portland, OR 97227

FOIA #BPA-2013-01716-F

Dear Mr. Koberstein:

This is a partial response to your request for records that you made to the Bonneville Power Administration (BPA) under the Freedom of Information Act (FOIA), 5 U.S.C. 552.

You requested:
"all documents related to the Columbia Generating Station condenser that are dated 2000 to 2013."

Response:
BPA is releasing the documents on the enclosed CD in their entirety.

Some material is still under review for Exemption 5 withholding. We anticipate being finished with that review by June 30, 2014.

I appreciate the opportunity to assist you. If you have any questions, please contact Kim Winn, FOIA Public Liaison, at 503-230-5273.

Sincerely,

/s/Christina J. Munro
Christina J. Munro
Freedom of Information/Privacy Act Officer

Enclosure: CD

MAIN CONDENSER REPLACEMENT PROJECT SCOPE OF WORK

05/22/08

A Condenser Conceptual Study R1 (Condenser Project on server 91) was completed February 29, 2008 by Westinghouse and Sargent & Lundy with input from consultants and CGS stakeholders. This study performed an evaluation of potential options for the main condenser module replacement to provide ENW the information required to understand the various complexities associated with replacing the main condenser modules.

Energy Northwest is responsible for the following **pre-R19**.

- Generating a Procurement Specification and initiate procurement of (12) titanium modules and (3) center water boxes for delivery at CGS
- Project Management
- Design/install temporary fabrication shop - material storage facility
- Provide the facilities for Industrial Area & Protected Area temporary housing
- S&L Engineering
    - Provide EC 6693: Removal of travel path interferences
    - Provide EC 6834: Permanent modifications within the Main Condenser required for R20 module replacement
    - Complete AR Evaluation 6086 Assignment 07 to provide an evaluation of the travel path of the main condenser tube bundles and west-end water boxes exterior to the TGB
- Westinghouse Engineering
    - Provide EC 6692: Performance Monitoring Instrumentation
- Temporary building design on East side of Bldg 62 (Primary Access Point)

The **Design and Installation Contractor's scope** of work associated with the Main Condenser Replacement project **pre-R19** is as follows:

- Provide and install housing facilities for the Industrial and Protected Areas
- Begin design of R-20 design modifications

The **Design and Installation Contractor's scope** of work associated with the Main Condenser Replacement project for **R19** is as follows:

- Detailed contractor expectations are identified in a RFP; an approved contract will better define the Installation Contractors responsibilities (contract Award expected by 10-1-08)
- Obtain as-built Main Condenser data
- Implement EC 6693: Removal of travel path interferences
- Implement EC 6834: Permanent modifications within the Main Condenser required for R20 module replacement
- Implement EC 6692: Performance Monitoring Instrumentation
- Install a gantry crane between the condenser and the west side bio-wall

- The following work is captured by Work Order which is both EC and non-design change activities :
    - Cut and Cap (2) 3" CAS Pipe
    - Relocate 2" Service Air Line

- Install Gantry Crane in Condenser Bay
- HWR Air Injection Skid
- Relocate H2 Piping Outside TG Building
- Relocate Power Control Cables Outside TG Building
- Relocate 12" Condensate Short Cycle Return Pipe
- Cut Access Hole in East Side Concrete Wall
- Cut Access Hole in West Side Concrete Wall
- Relocate 1 1/2" & 1" DW and W6 FP Pipes
- Modify FP C02 Lines
- #1FWH Supports
- Rail Removal System Supports Under Hotwell
- Cut and Cap 2" TSW Lines
- Stator Water Skid Piping
- Interferences on the East Side Concrete Wall
- Electrical Reroutes on West Side Travel Path - R-19
- Condenser Performance Monitoring - Pressure Instr. in the Main Condenser Shell
- Install Taps on COND Piping For Hotwell Cleanup (2)
- Install Temporary Shielding for West Concrete Wall
- Replace TE's 7A, 7B, 7C
- Install (8) Electric Hoist (HOI)
- Install Brackets for Camera's inside COND
- Relocate Flow Transmitter on Column 15 - C.6
- Move valve testing equipment
- Install Temporary Shielding for East Wall
- Remove Wall (Door Access Only) on West End 471' T
- Re-Install Wall (Door Access Only) on W. End 471' T
- COND-HX-9 Install Dissolved Oxygen Instrument
- TSW-V-78 Install Flow/Temperature Instruments
- COND-TE-4 Replace In R19
- CW-CT-1A Install Additional Flow Transducers I
- CW-CT-1B Install Additional Flow Transducers I
- CW-CT-1C Install Additional Flow Transducers I
- COND-TE-3 Replace In R19
- CW-TE-9A/9B/9C Replace In R19
- CW-CT-2A Install Additional Flow Transducers I
- CW-CT-2B Install Additional Flow Transducers I
- CW-CT-2C Install Additional Flow Transducers I
- CW-CT-1A Install New Temperature Elements
- CW-CT-1B Install New Temperature Elements
- CW-CT-1C Install New Temperature Elements
- CW-CT-2A Install New Temperature Elements
- CW-CT-2B Install New Temperature Elements
- CW-CT-2C Install New Temperature Elements

The **Design and Installation Contractor's scope** of work associated with the Main Condenser Replacement project **pre-R20** is as follows:

- Detailed contractor expectations are identified in a RFP; an approved contract will better define the Installation Contractors responsibilities (contract Award expected by 10-1-08)
- Security access improvements for personnel ingress/egress

- Security modification to Protected Area fencing for module transportation
- Relocate the Relief Valve test equipment
- Rigging for receipt of the new condenser modules
- Design and modify the Air Removal System piping to accommodate the new condenser modules air removal connections as required by new module fabricator
- Design change for new condenser design
- Provide a temporary RCA extension facility at the West TGB wall to handle the contaminated modules
- Cut opening in the West TGB wall for the RCA just prior to R20
- PDC 6693 activities (travel path interferences):
    - Re-route the FP piping on east side
- Install additional personnel facilities
- Install storage facility for the new modules

The **Design and Installation Contractor's scope** of work associated with the Main Condenser Replacement project for **R20** is as follows:

- Detailed contractor expectations are identified in a RFP; an approved contract will better define the Installation Contractors responsibilities (contract Award expected by 10-1-08)
- Specialty training (in addition to In-Processing training) for specialty work
- Provide temporary services (air, power, water)
- All construction work related to replacing the main condenser modules
- Restore Plant configuration (rails, cranes, mechanical/electrical interferences, temporary services, etc)
- Rebuild interior concrete bio-walls
- Modify the SJAE piping external to the Main Condenser

The **Design and Installation Contractor's scope** of work associated with the Main Condenser Replacement project **post R20** is as follows:

- Rigging/transportation for removal of contaminated condenser modules for disposal
- Demobilization (remove temporary equipment and facilities)
- Rebuild exterior turbine building wall and remove temporary building
- Project closeout and Engineering Changes (PDC) configuration control completed

Engineering Changes

- **PDC 6693** (S&L Proposals 00273-872R1) has been assigned to address removal of travel path interferences associated with transporting condenser components such as 'single stacked' condenser tube bundles and water boxes. The PDC will address travel path interferences that exist inside the TGB.

- **PDC 6834** (S&L Proposals 00273-878R1) has been assigned for permanent modifications to the main condenser that can be made in an outage prior to the replacement of the main condenser tube bundles. These modifications can potentially lessen the scope of work during the subsequent Condenser Replacement Outage (CRO). The proposal for PDC 6834 includes the following:

- Design and drawings for the installation of a drain and fill line to control liquid inventory in the condenser hotwell during the condenser replacement.
- Design and drawings for the installation of supports located underneath the inner bottom plate and bottom plate of the condenser necessary to support the rigging system to transport the condenser tube bundles.
- Design and drawings for the installation of 4 permanent condenser shell and 6 external temporary access hatches on Elevations 441' & 471' to provide for worker and equipment access to the main condenser.

- **AR Evaluation 6086 Assignment 07** (S&L Proposals 00273-876R1) has been assigned to provide an evaluation of the **travel path of the main condenser tube bundles and west-end water boxes <u>exterior</u> to the TGB**. As discussed in Proposal 00273-872 submitted by S&L, it is assumed that the east-end water boxes will be refurbished in the east condenser bay. Therefore, this proposal does not include scope of work associated with transport of the east-end water boxes outside the east condenser bay of the TGB.

- **PDC 6692** has been assigned for performance monitoring instrumentation for the main condenser (ASME PTC 12.2 requirements).
  - R19 Electrical Scope as follows:
    - Condenser Pressure Monitors (18 wireless)
    - Accuracy Improvements (replace 6 existing RTDs)
    - CT Riser Temperatures (12 new RTDs)
    - Sub-cooling RTDs (replace 2 existing RTDs)
    - Disolved Oxygen Sensors (1-2 sensors TBD)
    - Install wireless base radio and server (4 required)
    - Install 1 RTD and 1 Ultrasonic Flow meter to 30"TSW(2)-1
  - R20 Electrical Scope as follows:
    - Condenser Fouling Monitors (60 transmitters)
    - Wireless base radio
    - Data retrieval software

Attachments:

- S&L Proposal 00273-872R1 PDC 6693 Travel Path inside TGB R1.doc

- S&L Proposal 00273-878R1 PDC 6834 Main Condenser Mods R1.doc

- S&L Proposal 00273-876R1 AR Eval 6086-07 R1 Travel Path outside TGB.doc

- Main Condenser Project Scope Attachments\Input for 02-01-08 Baseline Cost Estimate for Huron Business Case (FY08-FY12).xls

ENERGY NORTHWEST

Condenser Replacement Project
R-19 Lesson Learned, Budget, Going Forward Plan for R-20 to VPTS

Project No. 00608601

July 6, 2009

Brian Berglin

Agenda

Safety	5 min
R-19 Successes & Lessons Learned	15 min
Status of Installation Contract for R-20	10 min
Condenser Module fabrication	5 min
Budget status & projections for Total Cost to completion	8 min
R-20 Schedule & Condenser Window Schedule	10 min
Round Table & Actions	5 min
Meeting Effectiveness	2 min

R-19 Successes

Scope of Work Completed

- Condenser Project
  - Removable biowall Sections installed on both the west (Column 15) & east (Column 6)
  - Hydrogen Water Chemistry piping and panels relocated
  - Six permanent access hatches installed on the condenser walls
  - Most Performance Monitoring Instrumentation installed
  - Installed Condenser Wall Stiffeners (on but not done)

R-19 Successes (continued)

Scope of Work Completed (Cont)

- Condenser Project (Cont)
  - Cleaned the false floor
  - Cleaned the hot well
  - Miscellaneous Piping & Hanger re-routes/changes to various Systems:

    CO2/Fire Protection Water/Floor Drain/Service Air/Control Air System/Plant Service Water (TSW)/Stator Cooling Water Tubing

R-19 Successes (continued)

- Condenser Maintenance Work Completed
  - Replaced Flexible (Dogbone) Seals in A,B,C Bays
  - Replaced slop drain piping in A,B,C Bays
  - Supported Eddy Current Testing of Condenser Tubes
  - Replaced two 30” expansion bellows in A Bay
- Walk downs
  - Yuba had 18 personnel walking down the condenser internals for one week during the R-19 outage.
  - R-20 Installation contractors walked down entire job including condenser internals for two days during the R-19 Outage.

R-19 Successes (continued)

- Other Condenser Maintenance Work completed
  - NDE hood spray piping in condenser bays
  - Repaired four hangers in condenser bays
  - Replaced 6 intermediate water box braces
  - Repaired SST deflector insulation on Cond-HX-1B

Scope of Work Not Completed

- Flow Meters for the Cooling Towers
  - Too expensive to install six flow meters
  - Plan to install one strap on flow meter on 12' Pipe during Cycle 20

R-19 Successes (continued)

Supplemental Personnel & EN Project Team

- No missed QC Hold Points
- No unqualified Personnel Working (PQD verification was an issue on 3 occasions)
- No lost time accidents
- No recordable injuries
- Secondary walk downs performed by contractor personnel. Packages worked without major re-writes to existing instructions

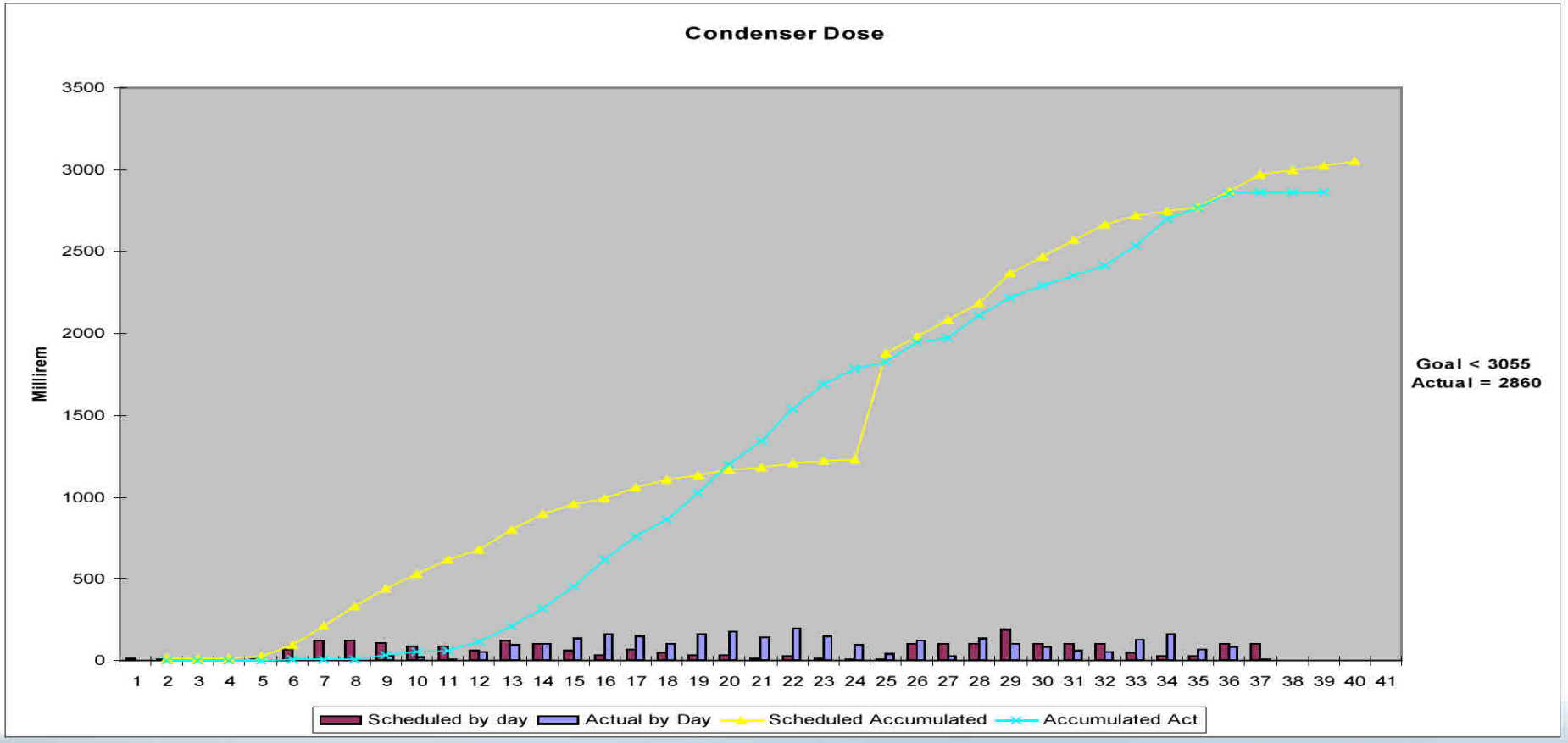
R-19 Successes (continued)

Supplemental Personnel & EN Project Team (Cont)

- Project Management briefs provided to contractor management every shift. Briefs included Safety, FME, Clearances, human performance and dose reduction
- Project Management and Field Engineering in the field reinforced Management expectations. Project completed on schedule & within budget.
- Pre-job briefs and Shift briefs emphasized human performance tools. Work completed without a safety stand down, rework or rigging incident.

R-19 Successes (continued)

- Completed all work within the ALARA goal budget (not the original budget)



ENERGY NORTHWEST

R-19 Lessons Learned

- Clearance Order and draining of the Condenser related systems took 4 days. Need to devise methods to reduce to 2 days. Initial entry needs to be coordinated and agreed to before hand.
- Turbine Generator had two points of entrance and one crane to support after one week into the outage. Need multiple cranes all the time.
- Access to the Turbine building was on a first come first serve basis and not schedule related

R-19 Lessons Learned (continued)

- Condenser Project needs to control schedule, turbine cranes, access to/from floor of turbine building during R-20.
- Condenser Project will need a building coordinator over the turbine building for R-20.
- Overhead lifts on the 501 Turbine deck need to be coordinated by the Condenser Team.
- Floor space maps were not effective. Condenser material/vans had to be moved. Overhead work was not taken into consideration.

R-19 Lessons Learned (continued)

- Condenser Entry procedure needs to be revised. It took the Project four days to gain entry.
- Establish IPM-8's on the east and west side of the condenser area to control contamination.
- Establish IPM-8 RCA access to and from the west side of the turbine building.
- Evaluate purchasing a SAM unit to move material/tools in and out of the RCA efficiently
- Turn styles into the RCA on the west entrance were not reliable.

R-19 Lessons Learned (continued)

- Will need dedicated HP coverage
- Radiation Procedures and Processes should not change after the milestone date
- Need consistent, agreed to before hand, interpretation of Radiation Protection requirements.
- Install weld rod issue station in the power block
- Develop a condenser specific scaffolding plan to support the condenser

R-19 Lessons Learned (continued)

- Need to manage the new NRC fatigue rule efficiently
- Balance the craft between shifts
- Schedule the close out inspection of the condenser, with owner.
- Project needs to own resources due to size
- Establish Energy Northwest representative now for support organizations needed in R-20
- Improve site communication. New Cisco radios were not reliable

R-19 Lessons Learned (continued)

- 30% of the craft personnel did not pass training requirements. Use stand up training if craft fail CBT the first time.
- Need to benchmark for confined space entry efficiency.
- Outage challenge meetings need to be earlier, not right before the outage
- Expand use of personnel trained for Designated Safety Representative, fall protection, confined space, fire watch, etc.

R-19 Lessons Learned (continued)

- Project team to work with Operations to develop a Clearance Order Plan that fits with the R-20 Project schedule and efficiency
- Schedule Work Orders/clearance orders/engineering packages so they all fit efficiently together.
- Hydro laze walls and floors of condenser bay after removal of condenser modules so clean area can be established during R-20.

R-19 Lessons Learned (continued)

- Need a plan to keep the condenser dry throughout the outage
- Coordinate use of Plant Design Change/Field Change Request drawings in the field during implementation
- Establish a common contamination area between A,B & C bay on the 441' level

Installation Contract for R-20

- Completed Items
  - Initial Proposals received 05-05-09
  - Competitive Range established 05-07-09
  - Competitive Range Contractors walked down internals of Condenser during R-19 Outage 06-01-09

ENERGY NORTHWEST

Installation Contract for R-20 (cont)

- Recent Events
  - All Offeror's have stated they will provide a fixed price proposal
  - Resolution of Commercial Terms and Conditions on track for resolution prior to Best and Final Offer
  - High Level of interest being shown by all bidding contractors & subcontractors

Installation Contract for R-20 (cont)

- Remaining current RFP Schedule
  - Draft RFP BAFO approved by SEP 07-30-09
  - Obtain approvals & issue BAFO 08-06-09
  - Issue Info Memorandum 08-06-09
  - Receive RFP BAFO from Contractors 09-04-09
  - SEP/CRB to evaluate BAFO 09-14-09
  - Executive Board approval 09-24-09
  - Award Contract or LNTP 09-28-09

Installation Contract for R-20 (cont)

- Proposed new RFP Schedule
  - Receive removal & install drwgs from Yuba 07-31-09
  - Contractors to meet with Yuba/EN 08-10-09
  - Draft RFP BAFO approved by SEP 08-31-09
  - Obtain approvals & issue BAFO 09-07-09
  - Issue Info Memorandum 09-10-09
  - Receive RFP BAFO from Contractors 09-30-09
  - SEP/CRB to evaluate & approve BAFO 10-08-09
  - Issue Action Memorandum 10-13-09
  - Executive Board approval 10-22-09
  - Award Contract or LNTP 10-30-09

Condenser Module Fabrication

- Titanium Tubes
  - 85% of the Tube material is at Valtimet (Tube Manufacturer)
  - 2% of the .035 wall Tubes have been fabricated
  - 15% of the .049 wall Tubes have been fabricated
  - 15% of the .022 wall Tubes have been fabricated

Condenser Module Fabrication (cont)

Timet Strip Rolls

New Tubes

ENERGY NORTHWEST

Condenser Module Fabrication (cont)

- Titanium Clad Tubesheets
  - 100% of the tubesheet material has been received at DMC (Tubesheet Manufacturer)
  - 100% of the seam welding is complete on all 6 sets
  - Bonding is complete on 2 of 6 sets
  - Drilling begins on first tubesheet 08-08-09

Condenser Module Fabrication (cont)

Tube sheet Plate

Tube sheet drilling

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Condenser Module Fabrication (cont)

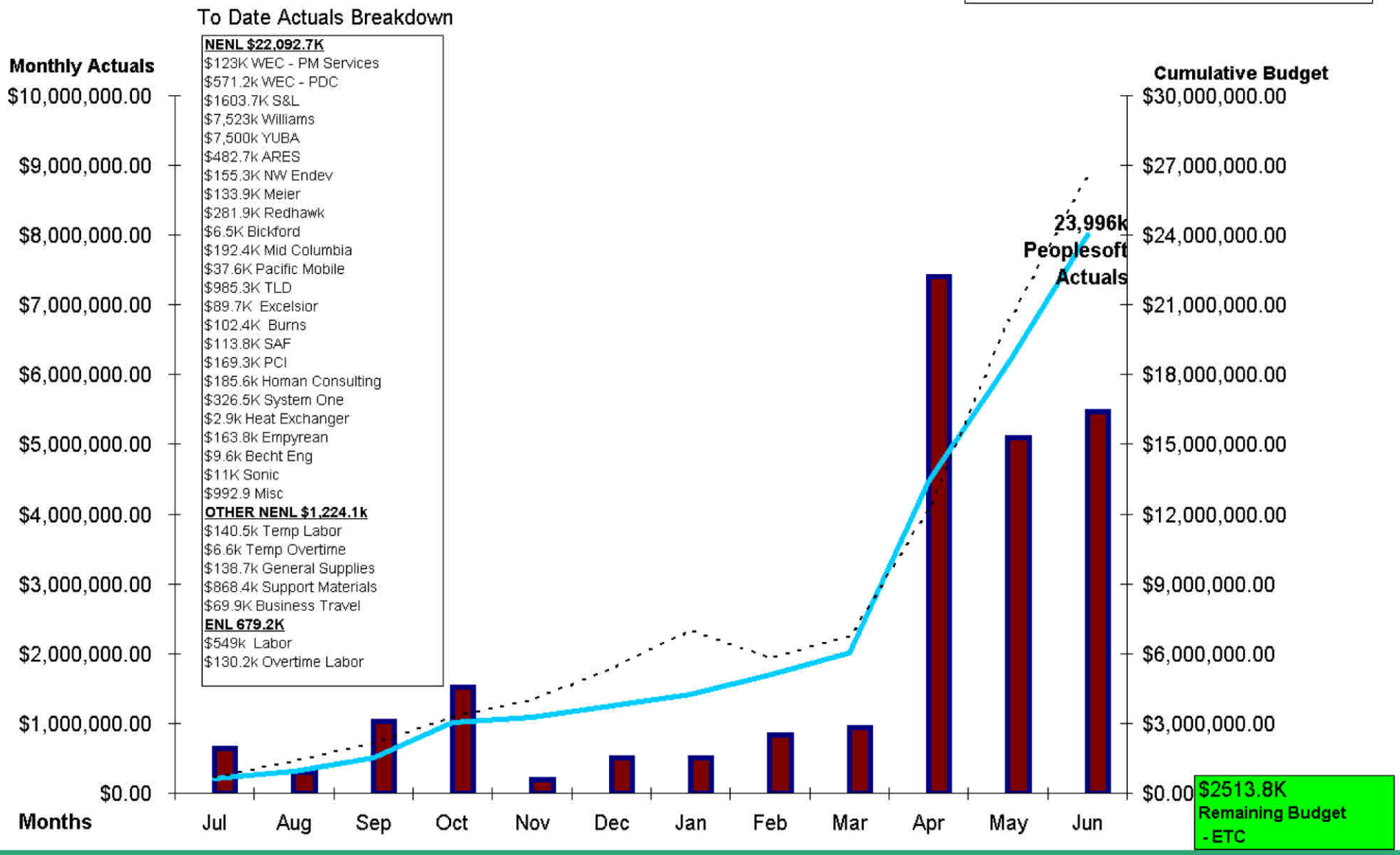
- Support Plates
  - 100% of the material has been received at YUBA's Manufacturing plant in Tulsa, OK.
  - 1 of the12 sets of support plates is finished being drilled, deburred and stored. Larry Syverson reports the quality is excellent
- Module Assembly Assembly starts 09-15-09
- Water box Manufacturing begins 09-28-09

Project Manager: Brian Berglin
EXT: 4265
Pager: 780-0962

Project 00608601 Main Condenser Replacement

6/30/09

Budget At Completion $26510K



Long Range Plan Budget

	FY08	FY09	FY10	FY11*	FY12*	Total
Business Case	4.31	36.49	27.64	30.28	8.09	106.81
Original LRP	4.01	25.00	26.80	30.60	8.46	94.87
Current LRP - 2/4/09	3.99	26.51	32.73	30.60	8.46	102.29
Actual & Current LRP	3.99	**23.996**	32.73	30.60	8.46	99.776

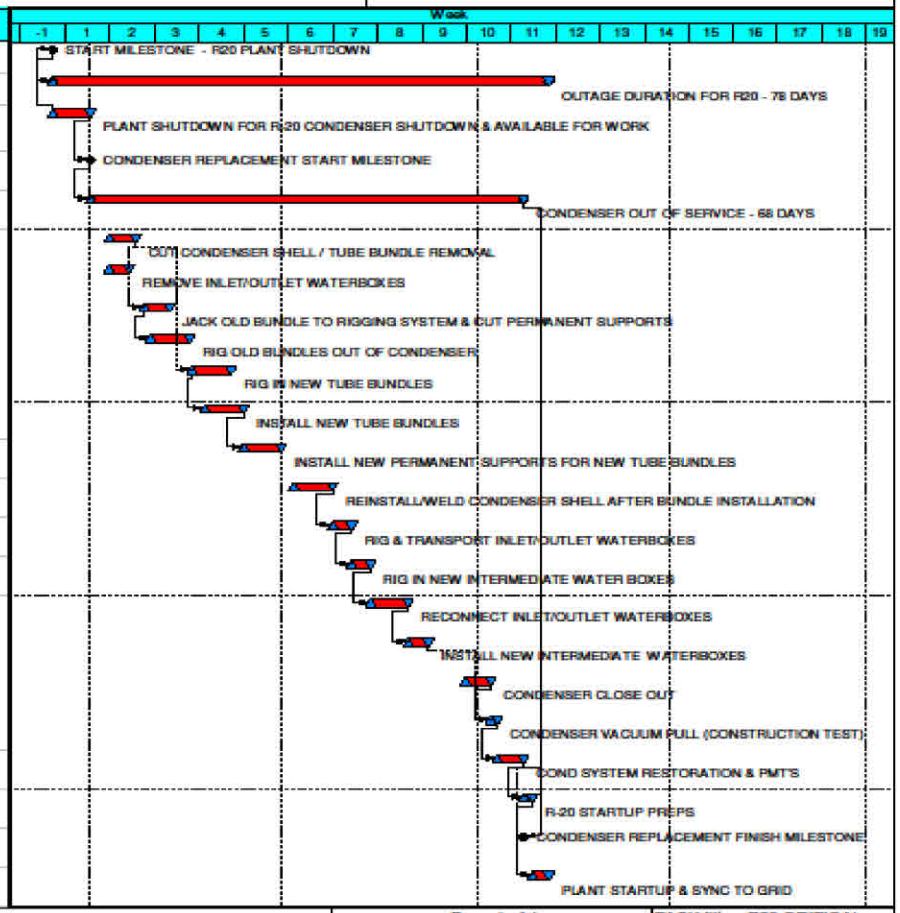
*Re-estimated when Best & Final Offer to Installation Contract is complete in 09-09

ENERGY NORTHWEST

R-20 SCHEDULE & CONDENSER WINDOW SCHEDULE

Rolly Fuller Test Plan | P6-OT R20 CRITICAL PATH - 78 DAYS | 25-Jun-09 12:33

Activity ID	Activity Name	Rem Dur	Start	Finish	FRAGNET CODE
CON005	START MILESTONE - R20 PLANT SHUTDOWN	0.0	26-Mar-11 00:01		R20CP
CON015	OUTAGE DURATION FOR R20 - 78 DAYS	1872.0	26-Mar-11 00:01	12-Jun-11 00:01	R20CP
CON003	PLANT SHUTDOWN FOR R-20 CONDENSER SHUTDOWN & AVAILABLE FOR WORK	144.0	26-Mar-11 00:01*	01-Apr-11 00:01	R20CP
CON023	CONDENSER REPLACEMENT START MILESTONE	0.0	01-Apr-11 00:01		R20CP
CON215	CONDENSER OUT OF SERVICE - 68 DAYS	1632.0	01-Apr-11 00:01	08-Jun-11 00:01	R20CP
CON071	CUT CONDENSER SHELL / TUBE BUNDLE REMOVAL	96.0	04-Apr-11 00:01	08-Apr-11 00:01	R20CP
CON231	REMOVE INLET/OUTLET WATERBOXES	72.0	04-Apr-11 00:01	07-Apr-11 00:01	R20CP
CON081	JACK OLD BUNDLE TO RIGGING SYSTEM & CUT PERMANENT	96.0	09-Apr-11 12:01	13-Apr-11 12:01	R20CP
CON091	RIG OLD BUNDLES OUT OF CONDENSER	144.0	10-Apr-11 12:01	16-Apr-11 12:01	R20CP
CON101	RIG IN NEW TUBE BUNDLES	144.0	17-Apr-11 00:01	23-Apr-11 00:01	R20CP
CON111	INSTALL NEW TUBE BUNDLES	144.0	19-Apr-11 00:01	25-Apr-11 00:01	R20CP
CON121	INSTALL NEW PERMANENT SUPPORTS FOR NEW TUBE BUNDLES	144.0	25-Apr-11 00:01	01-May-11 00:01	R20CP
CON141	REINSTALL/WELD CONDENSER SHELL AFTER BUNDLE INSTALLATION	144.0	03-May-11 00:01	09-May-11 00:01	R20CP
CON151	RIG & TRANSPORT INLET/OUTLET WATERBOXES	72.0	09-May-11 00:01	12-May-11 00:01	R20CP
CON161	RIG IN NEW INTERMEDIATE WATER BOXES	72.0	12-May-11 00:01	15-May-11 00:01	R20CP
CON171	RECONNECT INLET/OUTLET WATERBOXES	144.0	15-May-11 00:01	21-May-11 00:01	R20CP
CON175	INSTALL NEW INTERMEDIATE WATERBOXES	72.0	21-May-11 00:01	24-May-11 00:01	R20CP
CON213	CONDENSER CLOSE OUT	96.0	30-May-11 00:01	03-Jun-11 00:01	R20CP
CON185	CONDENSER VACUUM PULL (CONSTRUCTION TEST)	24.0	03-Jun-11 00:01	04-Jun-11 00:01	R20CP
CON195	COND SYSTEM RESTORATION & PMT'S	96.0	04-Jun-11 00:01	08-Jun-11 00:01	R20CP
CON055	R-20 STARTUP PREPS	36.0	08-Jun-11 00:01	09-Jun-11 12:01	R20CP
CON205	CONDENSER REPLACEMENT FINISH MILESTONE	0.0		08-Jun-11 00:01	R20CP
CON045	PLANT STARTUP & SYNC TO GRID	60.0	09-Jun-11 12:01	12-Jun-11 00:01	R20CP



Remaining Level of Effort | Remaining Work | Current Bar Labels
Actual Level of Effort | Critical Remaining Work | Milestone

Page 1 of 1

TASK filter: R20 CRITICAL PATH (78 DAYS).

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R-20 SCHEDULE – CRITICAL PATH SCOPE

- Plant Shutdown – Condenser Clearance Orders
- Remove block walls & install rails and floor
- Remove inlet & outlet water boxes
- Cut Condenser Shell
- Jack old bundles/cut supports/remove old modules
- Rig in & install new tube bundles & intermediate water boxes
- Install new permanent supports for new bundles & intermediate water boxes
- Install new permanent supports for new bundles
- Reconnect inlet & outlet water boxes
- Removal & installation of condenser instrumentation
- Condenser Vacuum pull

Meeting Summary

- Round Table Discussion
- Summarize Actions
- Closing Comments
- Meeting Effectiveness

CGS Condenser Replacement Project

ACPRT Review

Presentation to the CAB ***September 2008***

Scope

Methodology

Results

Scope and purpose

Scope of review

- **The Huron Study assessed the financial implications of two, operationally viable project alternatives under two installation timeframes**
  1. Titanium modular replacement installed in 2011
  2. Titanium modular replacement installed in 2015
  3. Titanium retube with new tubesheets in 2011
  4. Titanium retube with new tubesheets in 2015

- **The Huron Study concluded that alternative 1 – Titanium modular replacement installed in 2011 – was preferable**
  - Financially most advantageous

Net present values

(Expected values - $000)

	2011	2015
Modular titanium replacement	**5,535**	**(668)**
Titanium retube with new tubesheets	**(103,803)**	**(90,873)**

  - Modular replacement otherwise preferable to re-tubing alternative
    - less contamination risk, less risk of damage to tubes during installation (extends length of outage)*, improved thermal performance*

* Note: The Huron Study cited these as benefits of the modular replacement alternative that are above and beyond the NPV-financial benefits. In fact, these factors were captured in the NPV-financial analysis.

Scope of review

- **ENW justified and approved the project based on the Huron Study**
  - BPA non-disapproved FY 2008 funding (~$4 million sunk costs) (May 2007)
  - BPA has also non-disapproved FY 2009 funding (May 2008)
  - Procurement contract non-disapproval decision will be due in October
- **The ACPRT's "due diligence" review is focused on the methodology and assumptions Huron used to assess the financial implications of the four alternatives**
- **At the Administrator's direction, the ACPRT's review relies on existing, currently available materials and PGC expertise only**
- **No request has been made for supplemental information from ENW or Huron, and no standardized business case has been submitted**

Scope of review

- **Unlike other project reviews, the ACPRT is making no recommendation on a project alternative**
  - A full business case and access to Huron and to ENW SMEs would be needed first
  - Project execution risks are very large -- and access to a project plan to test risk management planning and controls would also be needed

- **Rather, we provide our critique of the Huron Study and our assessment of the alternatives' financial implications**

Methodology

Huron Study's methodology

- **The Huron Study employed net present value as the metric for determining the alternative that is financially most favorable**
  - Cash flows over the investment's expected life span were developed for each alternative
  - The cash flows for the alternatives were then discounted and compared
- **The Study then recommended the alternative shown to have the most favorable NPV**
- **In concept, Huron's approach – determine net present values based on life cycle cost and benefit cash flows – comports with BPA's approach to capital project valuation**

Huron Study's methodology

- **The Huron Study process was largely closed to BPA (PGC) and other stakeholder review and comment until it was completed in February 2008**

- **That said, the Study's analytical approach, assumptions, and results are documented**
  - BPA staff were provided access to the spreadsheets Huron used to determine cashflows and NPVs
  - For many data inputs, we know what was assumed but often not why

ACPRT's approach

- **The ACPRT's review was limited to the titanium modular replacement and titanium retube alternatives covered by the Huron Study**
  - We accept ENW's judgment that other alternatives – e.g., copper retube using existing tubesheets and stainless steel modular replacement -- are unacceptable from an operational/technical standpoint
- **ACPRT created a NPV-based model that starts with Huron's spreadsheets**
  - The model allows us to make corrections, updates and enhancements to Huron's analysis

The ACPRT employs the same financial metric, the same life-cycle cash flow approach, and essentially the same source data as Huron

ACPRT's approach

- **No changes were made to Huron's project cost data**
  - In other words, no changes were made to procurement, installation, testing and decontamination/disposal data for the modular replacement and retube alternatives
  - The Huron Study identified ENW and Industry SMEs as sources for these data
  - We had no access to these sources: therefore no ability to test the basis and uncertainties associated with project cost data
- **Updates and enhancements were made to market price and outage assumptions, data, and modeling**
  - to better ascertain the impact of alternatives on lost revenues, increased revenues, and replacement power costs
- **Several methodological and other analytical fixes were also been made to the financial analysis**

Problems found with Huron's modeling

- **Incremental cash flows in the Huron Study were not developed by comparison to a base case**
  - For purposes of determining net present values, cash flows must be incremental cashflows
  - The issue isn't whether the current condenser will need to be replaced or re-tubed – but rather *when* the installation will be most cost-beneficial
  - Therefore, the incremental cash flows for the 2011 and 2015 alternatives should be determined by reference to a "run to failure" base case
    - ACPRT's base case assumes that the current condenser will be replaced or re-tubed in 2018 (estimated end of condenser's useful life – PGC)
  - Modeling in the Huron Study effectively assumed that the current condenser would never fail
    - Some benefits are time-limited, but they were shown to continue over an indefinite period of time
      - *For example, the modular replacement alternative will increase generating capability over the long-term. But for purposes of determining incremental cash flows, these benefits should be counted between 2011 or 2015 and 2018 only*
    - Some benefits were not counted at all
      - *In particular, savings associated with avoiding the need to make a replacement in 2018, when determining incremental cash flows for the 2011 or 2015 alternatives*
  - The net effect of these problems is that the benefits of the alternatives were significantly understated

Problems found with Huron's modeling

- **Lost revenue/replacement power cost estimates did not fully capture market price and outage duration uncertainties**
  - ACPRT is now using BPA's most recent, probabilistic forecast of market prices
  - A "worst case" outage duration case has now been added (incremental 31, 40, and *62* days)
- **A couple of cost factors were improperly treated**
  - For example, eddy current testing (nondestructive testing) costs were calculated on a gross not incremental basis, and they were improperly treated in the cash flows
- **Horizon of cashflows extends beyond estimated useful service life**
  - Horizon of cash flows were limited to 20 years, with an estimate of the condenser's residual value inserted at year 20
    - Not a flaw in Huron's Study, but this change comports with BPA's treatment of other capital projects
    - ACPRT determined the residual value as net book value in year 20
- **Discount rate was not risk-adjusted and inconsistent with BPA's standard**
  - Huron Study: 6.5 percent (reflecting ENW's weighted average cost of capital)
  - ACPRT review: 13.0 percent (risk-adjusted discount rate for Federal hydro and all other capital projects in Power Services)

ACPRT modeling results

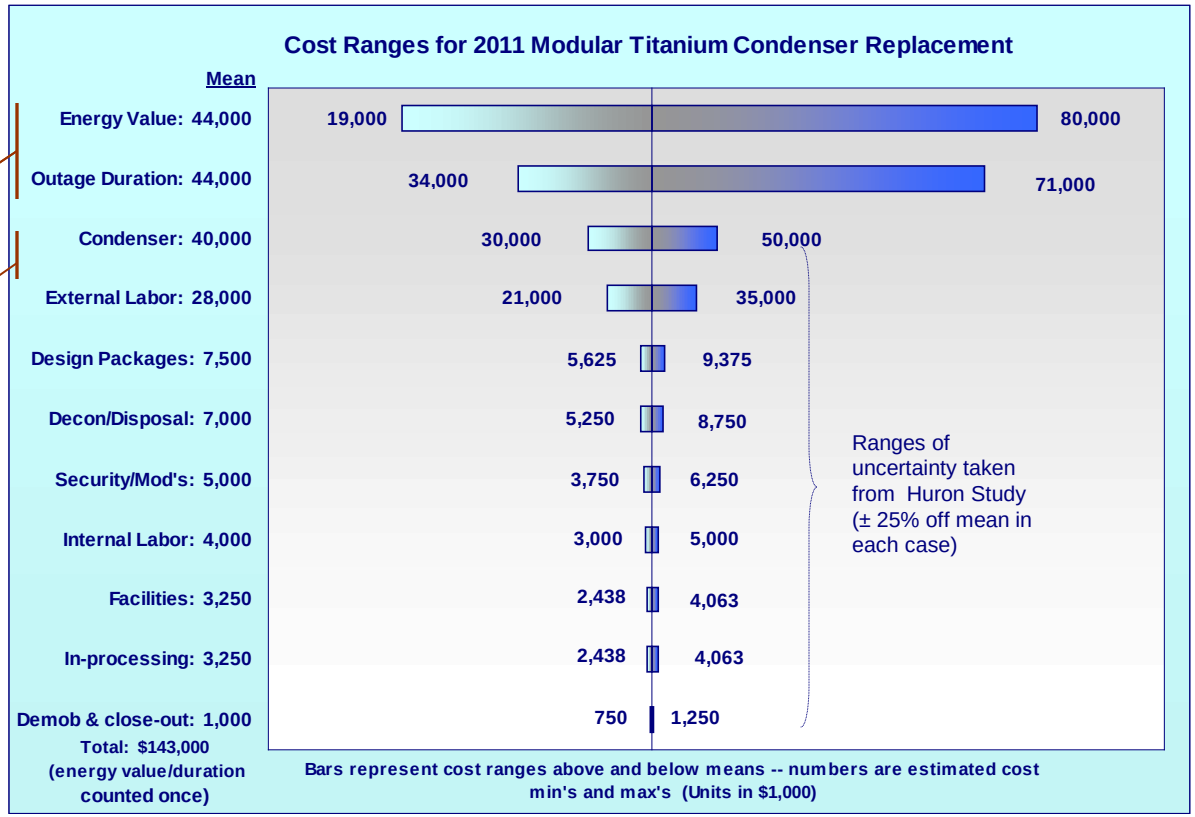
	Expected values					
	2011 Installation			2015 installation		
	Huron Study	ACPRT Review	Difference	Huron Study	ACPRT Review	Difference
Titanium modular replacement						
Project costs	106,370	106,938	568	120,933	120,915	(18)
Lost revenue/replacement power costs	71,756	43,669	(28,087)	80,841	46,739	(34,102)
Total costs	**178,126**	**150,607**	**(27,519)**	**201,774**	**167,654**	**(34,120)**
Net present values	**5,535**	**(20,224)**	**(25,759)**	**(668)**	**(3,599)**	**(2,931)**
Retube - titanium sheets						
Project costs	87,095	87,018	(77)	98,871	101,067	2,196
Lost revenue/replacement power costs	71,073	43,669	(27,404)	80,071	46,739	(33,332)
Total costs	**158,168**	**130,687**	**(27,481)**	**178,942**	**147,806**	**(31,136)**
Net present values	**(103,803)**	**(23,600)**	**80,203**	**(3,172)**	**(8,154)**	**(4,982)**

On an expected value basis, 2015 installation of the modular replacement alternative is the most favorable alternative

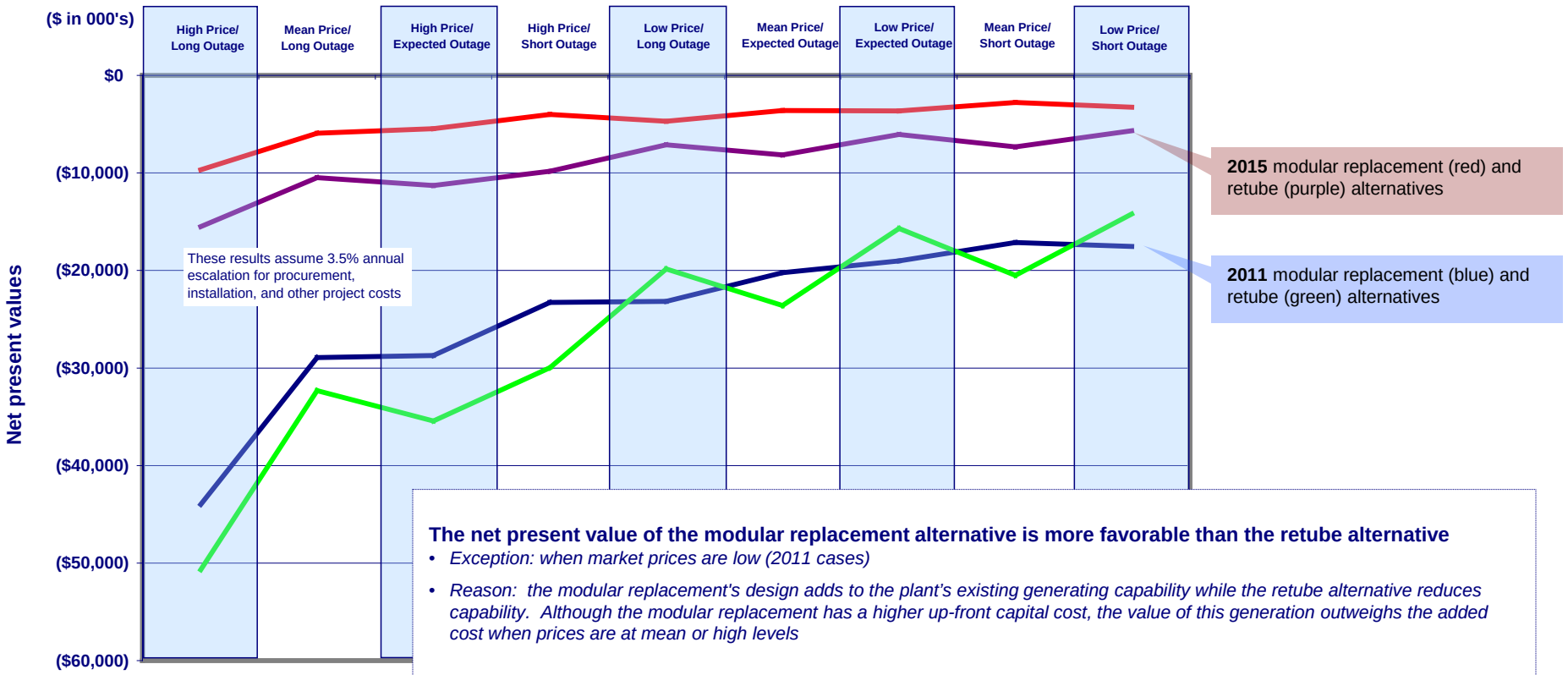
Cost uncertainties are very large

Market price and outage duration uncertainties are the biggest drivers

Procurement cost risks are also big, largely because of titanium price uncertainty. Uncertainty will be reduced in EN's vendor bid process now underway



NPV as a Function of Market Price and Outage Duration Variability



The net present value of the modular replacement alternative is more favorable than the retube alternative

- *Exception: when market prices are low (2011 cases)*
- *Reason: the modular replacement's design adds to the plant's existing generating capability while the retube alternative reduces capability. Although the modular replacement has a higher up-front capital cost, the value of this generation outweighs the added cost when prices are at mean or high levels*

Contrary to the Huron Study's findings, the project's value is improved if the installation date is delayed

- *Reason: In nominal terms, the benefits of this project are greater than its costs over the long haul. When discounting, whatever comes later is discounted more than what comes earlier, and this difference increases as a higher discount rate is applied. If a higher, risk-adjusted discount rate is used, the net present value of long-term project benefits declines relative to early project costs. Therefore, with BPA's discount rate (13.0% Vs Huron Study's 6.5%), pushing project costs out to a later installation date is more economic*
- *2011/2015 results can flip if titanium and other price inflation is significantly higher than the 3.5% rate used in Huron Study*

NPV variability is driven largely by the length of outage and prevailing market prices

- *Lost revenue/replacement power costs can more than double the NPV cost of the current 2011 installation plan*
- *Titanium price risk and other project risks are not reflected in this graph*

Managing cost risks

What could go wrong, and what steps should be taken?

Updated 9/30/2008

	Risks	Controls and Treatments
Timing	Project coincides with big unit outages at GCL results in higher power purchase expenses	• Coordinate with Federal Hydro; get condenser project done before GCL big unit outages (805 mw) begin in late August, 2012, and go on continuously for 10 years. • If condenser project done after 2012, shift the GCL schedule to create an opening for the condenser project
Approval Process	Insufficient information or time for BPA to approve or disapprove "term sheet" results in uninformed decision	• Need to inform PGC and EN that we need information well in advance of the 7 day " non-disapproval" process
	Project team / management doesn't adequately oversee the project resulting in delays and cost overruns	• PGC monitors as best they can and provides early warning of management problems
Cost	Value of lost energy during outage can be greater than estimates when project approved	• Review energy forecasts and prices and outage schedule before outage begins and develop energy strategy
	Titanium price escalates and EN/BPA ends up paying more	• Contractor takes price risk and incorporates it into project costs • EN takes risk and develops hedging strategy • PGC researches industry standard practice, BPA determines whether it has any preferences, and informs EN
Design	Condenser designed incorrectly resulting in delays and cost overruns	• Manufacturers visit CGS to get familiar with the plant and design requirements • EN quality assurance inspectors on site at manufacturer's plant
	Uncertainty about equipment design may cause large labor cost contingency to be built into installation bids	• *Resolve equipment design uncertainties* • *Send out "best and final offer" (BAFO) request with refined work scope* • *Re-do cost/benefit studies* • *EN does work themselves that they would otherwise contract out*

Italics = new actions not underway

Managing cost risks

What could go wrong, and what steps should be taken?

	Risks	Controls and Treatments
Manufacturing	Condenser manufactured incorrectly resulting in delays and cost overruns	• EN quality assurance inspectors on site at manufacturer's plant •
Installation	Overall	• EN develops outage plan and risk management plan • PGC has access to and reviews the outage plan, including the risk management plan • PGC performs on-going high level review of project progress • PGC attends Condenser Project Steering Committee meetings • EN and PGC visiting Laguna Verde as they install new condenser
	Prep work is insufficient (reinforcing structures needed when condenser is removed) resulting in delays and cost overruns	• Contingency plans • EN hiring industry expert consultants who have condenser replacement experience at other plants • EN ready to maintain existing condenser if install doesn't go right
	Labor shortages, possibly up to 400 in welding and other specialized fields, result in needing to extend the planned outage timeline	• Rely on industry practice/culture of sharing employees and contractors during outages • EN plans on barrowing workers from mid-west nuclear facilities • Summer outage at CGS won't coincide with the outage season in mid-west
	Something fundamentally flawed with the installation plan or CGS unable to receive a correctly designed condenser	• Outage plan reviewed by other utilities, manufacturers, BPA, others? • CGS visiting other plants to gather insights
	Equipment problems (e.g. Gantry crane can't be supported by CGS floor) resulting on delays and cost overruns	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
	Incorrect installation resulting on delays and cost overruns	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
	Schedule slippage	• Installer contract incentives
	Damage to condenser during installation	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
Restart	Plant doesn't restart as planned resulting in lost energy sales revenues or power purchase expenses	• Shake-out period incorporated into the scheduled outage duration • *Bulk Hub hedges forecasted extended outage period deficits with purchases, options, financials, etc., hedging any forecasted outage period surpluses by selling more cautiously*

Italics = new actions not underway

ENERGY NORTHWEST

Condenser Replacement Project
Design Engineering Support Services

Action Memorandum 1050

March 26, 2008

Brian Berglin

BACKGROUND

- Recent decision to replace the Main Condenser
  - Admiralty Brass Tubes to Titanium Modules
  - Designated R-20 (May 2011) replacement
- Completed Conceptual Study & Business Case
  - R-19 (May 2009), On-line & R-20 Design Work identified
- R-19 Design Work Required
  - Minimize impact on R-20 outage
  - 70% of Scope Identified in Conceptual Study

BACKGROUND (continued)

- Verbal information notification by VPG provided to the Board in February 2008
- Work normally performed in series must be performed in parallel

Scope of Work

- EC 6693 Condenser Travel Path External Interferences
  - West (and potentially East) concrete wall removal & temp shielding
  - Install Gantry Crane in condenser bay
  - Relocate various piping interferences
- EC 6834 Condenser Internal Work
  - ✓ Large man-way access to shell interior
  - ✓ FWH 1A/1B/1C supports
  - ✓ Rail Removal system supports under hot well
- AR 6086 AS#7 O/S TGB Travel Path Evaluation

To ensure no pipes are crushed

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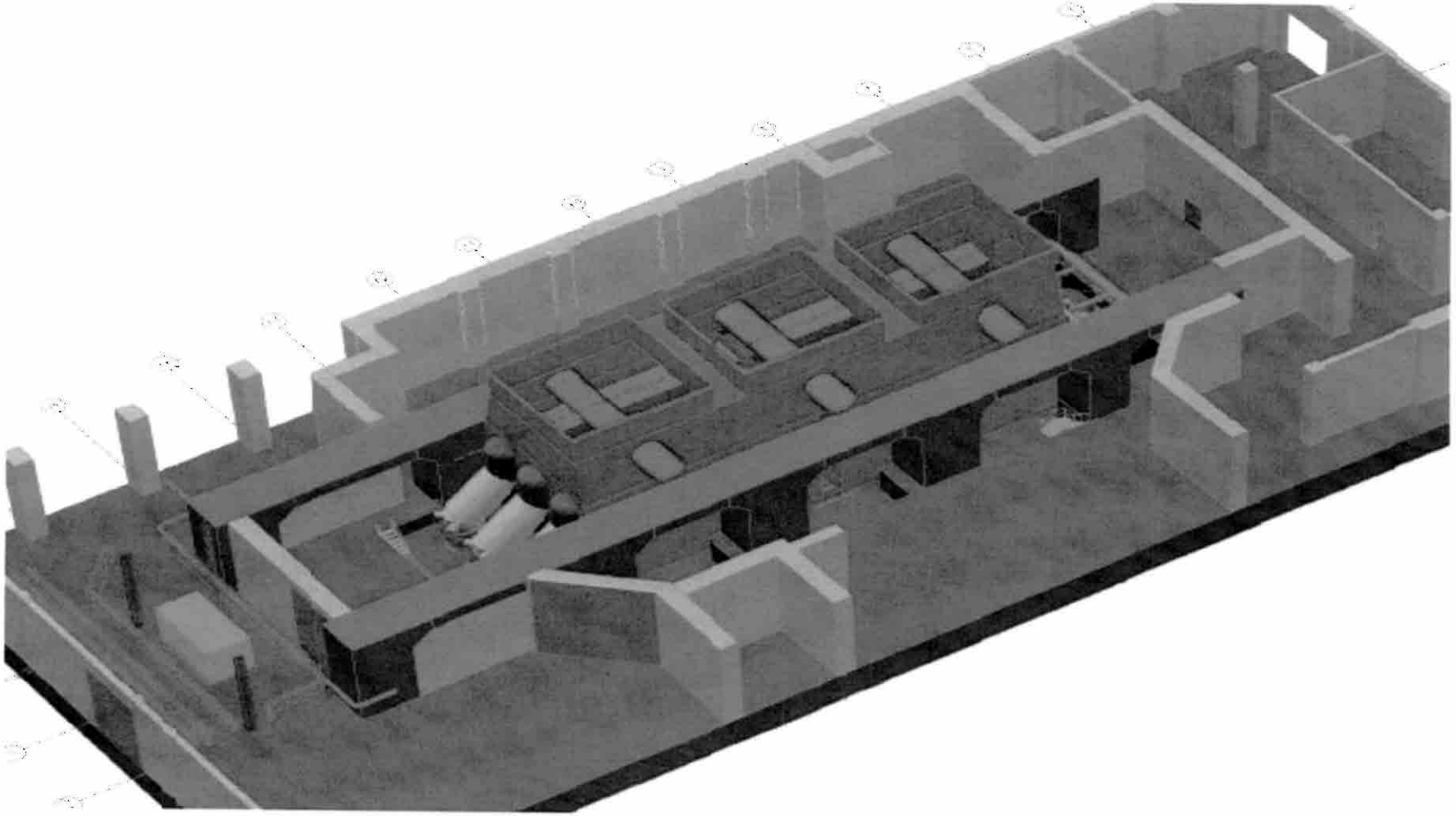
Main Condenser Project: 3D overview



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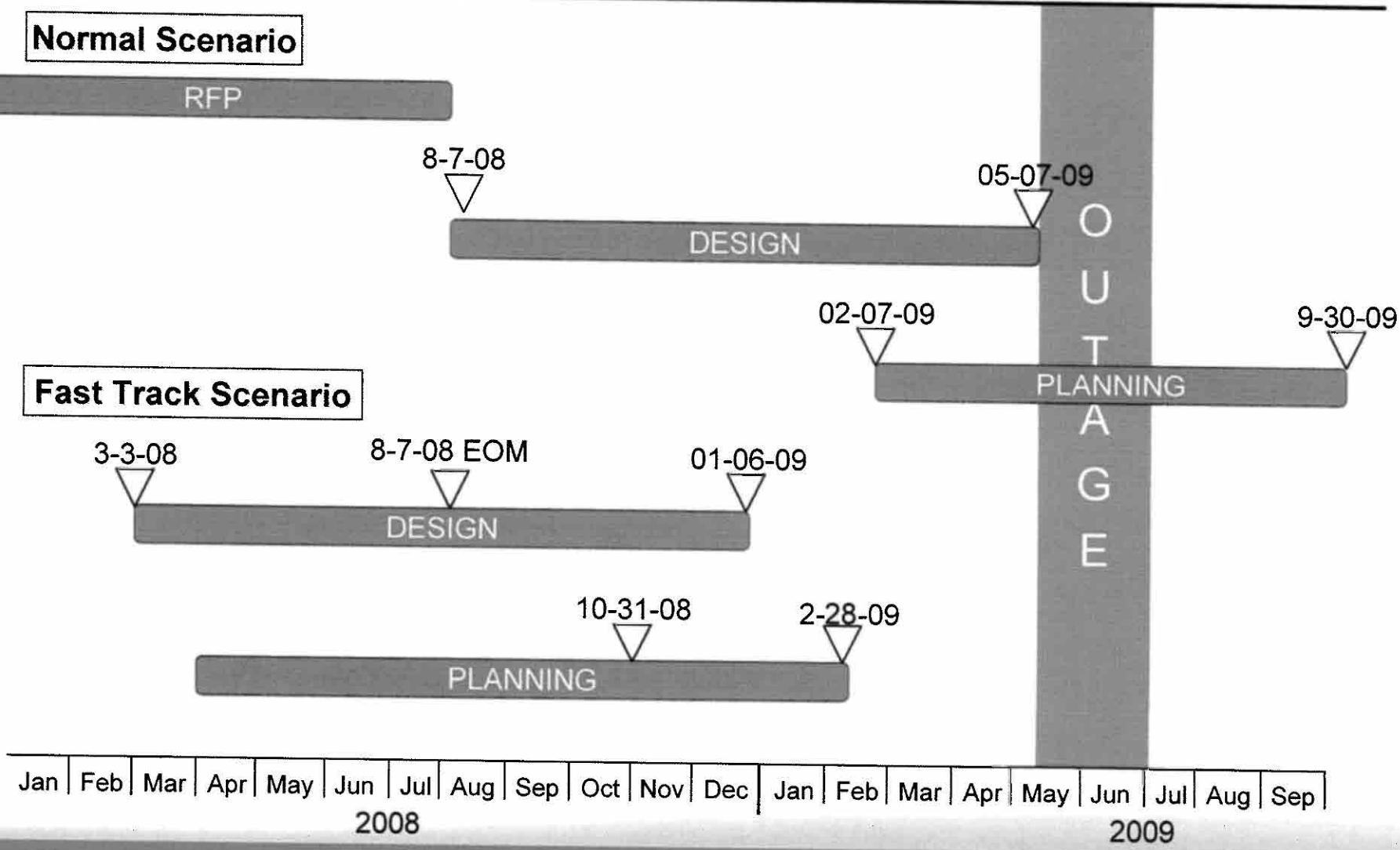
Evaluation

- Sargent & Lundy personnel to be used on the project are experienced with similar previous work at Columbia
- Engineers to be qualified through established Appendix B program (recent efficiency change at the station)
- Sargent & Lundy is a one of the preferred Architectural Engineering firms currently under contract
- Most expedient and efficient method to start R-19 Engineering and recover the schedule

R-19 Design & Planning Schedules



ENERGY NORTHWEST

Recommendation

- Award Main Condenser Replacement Project R-19 Design Engineering Contract to Sargent & Lundy for $1,636,500.

Department of Energy

Bonneville Power Administration
Mail Drop 1399
P.O. Box 968
Richland, Washington 99352-0968

POWER SERVICES

November 10, 2008

In reply refer to: PGC/Richland

Mr. S. K. Gambhir, Vice President
Technical Services
Energy Northwest M/D PE04
P. O. Box 968
Richland, WA 99352-0968

Dear Mr. Gambhir:

In reference to your letter "Energy Northwest RFP 651803 Main Condenser Replacement Modules," dated October 23, 2008, and received on November 7, 2008, the Bonneville Power Administration does not disapprove the execution of the proposed contract action.

The proposed action would authorize Energy Northwest to execute a contract as a result of RFP 651803 with Thermal Engineering International (TEI), in an amount not to exceed $37,000,000 for design, manufacture and delivery of twelve condenser modules in support of the Main Condenser Replacement Project which is planned for execution during the R-20 refueling outage.

Sincerely,

for Andrew J. Rapacz, Manager
Contract Generating Resources

cc:
Mr. Brian G. Berglin, Energy Northwest - 964F
Ms. Lynne A. Pagel, Energy Northwest - PE10

bcc:
Official File – PGC (PM-14-23) (Columbia)
ERMS: http://bpaweb/services/erms/PM/14/23/PGC%20Records/Forms/AllItems.aspx

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BONNEVILLE POWER ADMINISTRATION
CONTRACT GENERATING RESOURCES (PGC)
Briefing Paper, Columbia Generating Station (CGS)
Action Memorandum No. 1079
CGS Main Condenser Replacement Modules

REFERENCES: 1) Energy Northwest letter to A. J. Rapacz, "Energy Northwest RFP 651803 Main Condenser Replacement Modules," dated October 23, 2008, and received on November 7, 2008.

2) Briefing Paper to Energy Northwest letter to A. J. Rapacz, "Energy Northwest Agreement 319873 Contract Release 28 Main Condenser Project Design Support," dated March 24, 2008, and received on April 1, 2008.

3) Briefing Paper to Energy Northwest letter to A. J. Rapacz, "Energy Northwest Agreement 326930 Main Condenser Project Design Support," dated August 27, 2008, and received on September 8, 2008.

CONTRACT: Energy Northwest Action Memorandum No. 1079 Columbia Generating Station Main Condenser Replacement Modules to Thermal Engineering International (TEI).

ACTION TOPIC: Energy Northwest has requested BPA's non-disapproval for execution of Action Memorandum 1079 for RFP 651803 Main Condenser Replacement Modules, to TEI, in an amount not to exceed $37,000,000 for design, manufacture and delivery of twelve main condenser modules in support of the Main Condenser Replacement Project. Replacement of the main condenser is planned for execution during the R-20 refueling outage (FY 2011).

DISCUSSION: The Main Condenser Replacement Project has been broken down into two principal segments based on the two main requests for proposal (RFP): 1) contracts associated with RFP 651803 for design, fabrication and delivery to the site of replacement condenser modules, and 2) contracts associated with RFP 651804 for performance of tasks necessary for the removal of the existing condenser modules and installation of the new replacement condenser modules. The contract that will result from execution of this Action Memorandum is part of a larger overall effort executed as a phased approach to replace the main condenser tubing and supports with pre-fabricated titanium modular bundles. The phased approach is described in more detail in Reference 2. Reference 3 documents the engineering services for condenser performance monitoring instrumentation and is included here for completeness only.

The purpose of this contract is to provide design engineering services, manufacturing and delivery of 12 main condenser replacement modules to be installed during the R-20 refueling outage. Additional requirements are in accordance with Procurement Specification 12502, and TEI shall coordinate work with Energy Northwest and Energy Northwest's installation contractor(s) performing the project management, engineering and installation of the condenser modules.

TEI was selected based on pre-established weighted evaluation criteria as being the most technically advantageous and representing the lowest cost to Energy Northwest. The competitive negotiation process was used with RFP 651803 issued on May 23, 2008. Responsive proposals were received August 6, 2008, from Westinghouse (Toshiba), Yuba Heat Transfer, and TEI. Following vendor discussions and Plant visits with all three responsive companies, a request for

Best and Final Offers (BAFO) was issued on September 29, 2008. The BAFOs were received from all three vendors on October 9, 2008. The proposal evaluation included eight technical and two commercial criteria. The eight technical criteria are summarized as follows: response to procurement specifications and work requirements completeness; relevant experience; team composition and qualifications and experience; fabrication capability and capacity; guaranteed performance; consideration of schedule; technical alignment with Energy Northwest and project ownership; and overall technical adequacy of the proposal including likelihood of meeting the July 7, 2010 delivery date. The two commercial criteria included acceptance of terms and conditions and cost.

The contract is a fixed price contract having liquidated damages for late module delivery and provisions for performance payment adjustments for increased / decreased condenser performance. The contract costs include a fixed price element and allowances for cost reimbursement elements such as performance bond and transportation costs.

The main condenser is a critical component and is required for operation of CGS. Sustained poor maintenance and inadequate foreign material exclusion control has created a situation of condenser tube failure and resulting unplanned plant down powers for tube leak repairs. Energy Northwest's technical staff estimate the end of useful life of the current main condenser is 2018. Additional concerns related to high levels of copper (Admiralty Brass) contained in the current condenser tube material challenge reliable operation and minimization of radiation dose to employees. Reliable operation of this system is a high priority for Energy Northwest. The maintenance and repairs performed during the last refueling outage (R-18) have proven effective with no measurable tube leaks to date. Energy Northwest does anticipate however, that new tube leaks will develop at some point in the future. With the extensive tube plugging in R-18, it is hoped that CGS can run until R-19 with minimal leaks. As stated by the Energy Northwest VP of Technical Services at the March 2008 Board of Directors meeting, the continued operation of the main condenser is not a nuclear safety issue.

FUNDING: Funding for this contract is included in the approved FY 2009 Budget and the planned budgets for FY 2010 and FY 2011.

ISSUES: None with this action.

ACTION: BPA agrees replacing the main condenser tubing will improve the system reliability and significantly addresses reliability concerns. PGC staff will prepare a letter of non-disapproval.

bcc: Official File – PGC (PM-14-23) (Columbia)
ERMS: http://bpaweb/services/erms/PM/14/23/PGC%20Records/Forms/AllItems.aspx

PESmith:dc:5130:11/10/08 (W:\Office\Briefing Papers\CY 2008 papers\m 1079 Main Condenser Module Fabrication pes.doc)

Reviewed: PES 11/10/2008 PES 11/10/2008
PES / date AJR / date

Sudesh K. Gambhir
Vice President, Technical Services
P.O. Box 968, PE04
Richland, WA 99352-0968
Ph. 509.377.8313 | F. 509.377.2354
sgambhir@energy-northwest.com

October 23, 2008

BPA
NOV 7 2008
RICHLAND

Mr. Andrew J. Rapacz, M/D 1399
Manager Contract Generating Resources
Bonneville Power Administration
U.S. Department of Energy
c/o Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

Dear Mr. Rapacz:

Subject: **ENERGY NORTHWEST RFP 651803**
MAIN CONDENSER REPLACEMENT MODULES

Energy Northwest intends to execute a Contract as a result of RFP 651803 with Thermal Engineering International (TEI) in the not-to-exceed amount of $37,000,000. The contract will be for the design, manufacture and delivery of twelve condenser modules to replace the existing modules at the Columbia Generating Station. Details of the aforementioned transaction are contained in the attached Findings of Fact.

This contract action is subject to the right of the Administrator, Bonneville Power Administration, to disapprove pursuant to the Project Agreement.

Respectfully,

S.K. Gambhir
Vice President, Technical Services

/wge

Attachment

FINDINGS OF FACT

COLUMBIA GENERATING STATION RFP 651803

MAIN CONDENSER REPLACEMENT MODULES

SCOPE

This scope of work is for the analysis, design, manufacture, and delivery of replacement condenser modular bundles, and all other requirements in accordance with Procurement Specification 12502. In addition, the Supplier shall coordinate work with Energy Northwest and Energy Northwest's Installation Contractor(s) performing the project management, engineering and installation of the condenser modular bundles at the Columbia Generating Station.

BACKGROUND

The Columbia Generating Station Main Condenser Replacement Project has been broken into two principal segments: (1) the Design, Fabrication, and Delivery to the project site of Replacement Condenser Modules; and (2) Contract(s) for the performance of tasks necessary for the removal of the existing condenser modules and installation of the new replacement condenser modules.

RFP 651803, using the competitive negotiation process was issued on May 23, 2008, requesting proposals for the design, fabrication and delivery of replacement condenser modules. Responsive proposals were received on August 6, 2008, from the following three vendors: Westinghouse (Toshiba), Yuba Heat Transfer, and Thermal Engineering International (TEI). Following vendor discussions and plant site visits with all three proposers, a request for Best and Final Offers was issued on September 29, 2008.

DISCUSSION/NEGOTIATION RECORD

Best and Final Offers (BAFOs) for the replacement condenser modules were received on October 9, 2008, from all three vendors. These BAFOs were evaluated by a Source Evaluation Panel (SEP) using pre-established weighted evaluation criteria. The SEP ranked the proposal provided by TEI as being technically most advantageous and representing the lowest cost to Energy Northwest.

Efforts to identify the most cost effective means of performing the tasks necessary for the removal of the existing condenser modules and installation of the new replacement condenser modules during the R-20 outage are ongoing. Award of the module vendor contract will assist these efforts by eliminating current design unknowns and by clarifying installation task scopes.

FINDINGS OF FACT RFP 651803 (cont)

EVALUATION

Evaluations of the Submitted proposals were conducted by a Source Evaluation Panel (SEP) with over site by a Contract Review Board (CRB). The SEP makes its recommendation to the Source Selection Official (SSO) who has the responsibility of making the final decision. See the attached documents for details related to the personnel performing the evaluations, evaluation of submitted prices, and selection criteria with evaluation points used to reach a recommendation for award to the SSO.

- MAIN CONDENSER REPLACEMENT PROJECT PROCUREMENTS -- Appointment of Source Selection Official (SSO) including the Source Evaluation Panel (SEP) and Contract Review Board (CRB).

- BAFO Pricing Comparison For RFP 651803 Condenser Module Procurement

- Condenser Module Proposal Evaluation Criteria for RFP 651803 including assignment of points by the SEP.

FUNDING STATEMENT

This procurement is authorized by Pass Port Contract Requisition No. 651803 having an estimated value of $36,316,827. Costs will be allocated to Work Order 01125228 – 15.

SPECIAL PROVISIONS

The contract is a fixed price contract having liquidated damages for late module delivery and provisions for performance payment adjustments for increased / decreased condenser performance.

RECOMMENDATION

It is recommended that a contract be awarded to Thermal Engineering International in the not-to-exceed amount of $37,000,000 for the design, fabrication, and delivery of Replacement Condenser Modules as described in RFP 651803. This price includes a fixed price element and allowances for cost reimbursement elements such as performance bond and transportation costs.

FINDINGS OF FACT RFP 651803 (cont)

APPROVALS

Prepared By: W. G. Edmonds — 10-23-2008

W. G. Edmonds, Pr. Contracting Officer — Date

CONCURRENCES:

10-24-08

B. G. Berglin, Condenser Replacement Project Manager — Date

10/27/08

P. R. Bradley, Assistant General Counsel — Date

10-27-08

D. A. Swank, Manager, Major Projects — Date

10/28/08

G. A. Sponholtz, Supervisor, Purchasing & Contracts — Date

10/28/08

L. A. Pagel, Manager, Supply Chain Services — Date

11/06/08

S. K. Gambhir, VP Technical Services — Date

ENERGY NORTHWEST

P.O. Box 968
Richland, WA 99352-0968

ACTION MEMORANDUM NO. 1079

COLUMBIA GENERATING STATION MAIN CONDENSER REPLACEMENT MODULES

PURPOSE

The purpose of this Action Memorandum is to obtain Executive Board approval for the award of a contract for procurement of condenser modules associated with the Columbia Generating Station Main Condenser Replacement Project.

BACKGROUND

The Columbia Generating Station Main Condenser Replacement Project has been broken into two principal segments: (1) the design, fabrication, and delivery to the project site of replacement condenser modules; and (2) contract(s) for the performance of tasks necessary for the removal of the existing condenser modules and installation of the new replacement condenser modules.

Using the competitive negotiation process, a Request for Proposal (RFP 651803) was issued on May 23, 2008, for the design, fabrication and delivery of replacement condenser modules. Responsive proposals were received on August 6, 2008, from the following three vendors: Westinghouse (Toshiba), Yuba Heat Transfer, and Thermal Engineering International (TEI). Following discussions and plant site visits with all three vendors, a request for Best and Final Offers was issued on September 29, 2008.

DISCUSSION

Best and Final Offers (BAFOs) for the replacement condenser modules were received on October 9, 2008, from all three vendors. These BAFOs were evaluated by a Source Evaluation Panel (SEP) using pre-established weighted evaluation criteria. The SEP ranked the proposal provided by TEI as being technically most advantageous and representing the lowest cost to Energy Northwest.

Efforts to identify the most cost effective means of performing the tasks necessary for the removal of the existing condenser modules and installation of the new replacement condenser modules during the R-20 outage are ongoing. Award of the module vendor contract will assist these efforts by eliminating current design unknowns and by clarifying installation task scopes.

RECOMMENDATION

It is recommended that the Executive Board authorize the award of a contract to Thermal Engineering International in the not-to-exceed amount of $37,000,000 for the design, fabrication, and delivery of replacement condenser modules as described in RFP 651803. This action is subject to the contractual rights of the Bonneville Power Administration and the Participants' Review Board.

Office of the Chief Executive Officer

10/20/2008
Date

ACTION MEMORANDUM NO. 1079
CONCURRENCE PAGE

CGS MAIN CONDENSER REPLACEMENT MODULES

Prepared By: W. G. Edmonds — 10-16-2008
W. G. Edmonds, Pr. Contracting Officer — Date

CONCURRENCES:

B. G. Berglin, Condenser Replacement Project Manager — 10-16-08 Date

D. A. Swank, Manager, Major Projects — 10-16-08 Date

G. A. Sponholtz, Supervisor, Purchasing & Contracts — 10-16-08 Date

L. A. Pagel, Manager, Supply Chain Services — 10-16-08 Date

S. K. Gambhir, VP Technical Services — 10-16-08 Date

(pb) A. E. Mouncer, VP, Corporate Services/General Counsel/CFO — 10-20-08 Date

DRAFT

EXECUTIVE BOARD

RESOLUTION NO. 1584

A RESOLUTION AUTHORIZING THE EXECUTION OF A CONTRACT WITH THERMAL ENGINEERING INTERNATIONAL FOR MAIN CONDENSER REPLACEMENT MODULES - COLUMBIA GENERATING STATION

By Executive Board Information Memorandum No. 680, issued in September 2008, Energy Northwest staff notified the Executive Board of its intention to divide the Columbia Generating Station (CGS) Main Condenser Project into two principal segments: (1) the design, fabrication, and delivery to the project site of replacement condenser modules; and (2) contract(s) for the performance of tasks necessary for the removal of the existing condenser modules and installation of the new replacement condenser modules, and

The Chief Executive Officer reports that this procurement would be by competitive negotiation pursuant to RCW 43.52.565 in light of the Chief Executive Officer's determination that execution of the contract under said statute would accomplish project completion and operation more economically than sealed bids, and

The Chief Executive Officer further reports that using the negotiated competition procedure, a Request for Proposal (RFP 651803) was issued for the design, fabrication, and delivery of replacement condenser modules. Responsive proposals were received from Westinghouse (Toshiba), Yuba Heat Transfer, and Thermal Engineering International. Following discussions and plant site visits with all three vendors, Energy Northwest requested the submittal of Best and Final Offers. Based upon the evaluation of the proposals and Best and Final Offers, the staff determined that the proposal submitted by Thermal Engineering International was the most advantageous to Energy Northwest, and

Having reviewed the foregoing, the Executive Board finds that the execution of a contract with Thermal Engineering International is most advantageous to Energy Northwest and the State of Washington, taking into consideration the

requirements set forth in the Request for Proposals, and is in the best interests of Energy Northwest and the electric ratepayers of the Pacific Northwest, and

The Executive Board further finds that the use of the negotiated competition procedure as described within RCW 43.52.565 as a method for making a contractor selection to perform the design, fabrication, and delivery of replacement condenser modules at Columbia Generating Station will accomplish project completion and operation more economically than sealed bids; NOW, THEREFORE,

IT IS RESOLVED that the offer of Thermal Engineering International to provide Main Condenser Replacement Modules at Columbia Generating Station, identified in its proposal, its Best and Final Offer, and the plans and specifications, is accepted, and the Chief Executive Officer or his designee is authorized and directed to execute a contract with Thermal Engineering International in an amount not to exceed $37,000,000 in accordance with its offer, subject only to the contractual rights of the Bonneville Power Administration and the Participants' Review Board.

ADOPTED by the Executive Board of Energy Northwest this 23rd day of October, 2008.

_____
Chairman

ATTEST:

_____
Secretary

APPROVED AS TO FORM
AND LEGALITY:

_____
Counsel

Condenser Module Proposal Evaluation Criteria RFP 651803

Evaluation Item	Weight	Points		
		Supplier Name		
		Toshiba	Yuba	TEI
TECHNICAL EVALUATION				
1. Offeror's Response to Procurement Specification/Statement of Work Requirements Completeness	**125**	60	90	110
2. Offeror's Relevant Experience	**125**			
a. Performance-Delivery Record.	15	15	15	15
b. Past Pullout test Historical Performance.	5	2	4	4
c. Demonstrated experience of similar size condenser fabrication and nuclear experience.	10	7	8	8
d. Demonstrated commitment to long term success in condenser replacement	10	10	10	10
e. Past responsiveness to engineering and field modifications	10	5	8	10
f. Previous condenser historical performance record.	75	75	70	70
3. Proposed Team Composition including Qualifications and Experience	**55**			
a. Key personnel	10	2	8	10
b. Proposed subcontractors	5	5	1	5
i. Tube subcontractor's QA and procedural compliance	40	10	30	40
4. Consideration of Offeror's Design and Fabrication Capability and Capacity	**30**			
a. Facilities and manufacturing processes	15	15	8	10
b. QA Program	15	5	10	14
5. Guaranteed performance	**60**			
a. Guaranteed Vacuum performance level (Desired 2.41 max)	60	60	55	60
b. Guaranteed Condensate Temperature Depression (3 degrees F max) *				
6. Consideration of Offeror's Schedule (including subcontractors)	**65**			
a. Fabrication schedule	30	10	20	30
b. Delivery Plan and resource loaded schedule	25	5	18	25
c. Technical and contractual risks	10	5	8	10
7. Offeror's:	**50**			
a. Technical and administrative alignment with Energy Northwest	10	4	8	10
b. Technical interchange of information	10	4	8	10
c. Project ownership	30	10	22	30
8. Overall technical adequacy of the proposal and the likelihood, as judged by Energy Northwest, that the Offeror can meet a required delivery date of July 7th, 2010 given the estimated award date of November 15th, 2008.	**50**	30	38	48
SUB-TOTAL WEIGHT	**560**	339	439	529
COMMERCIAL EVALUATION				
1.0 Acceptance of Terms and Conditions	**100**	60	40	25
2.0 Cost	**250**	205	245	250
SUB-TOTAL WEIGHT:	**350**	265	285	275
TOTAL WEIGHT:	**910**	604	724	804

* Re-heat was provided as an option for BAFO in Addendum 9, Option 2 of the Pricing sheet. The Project team determined from visiting all vendors and evaluating each design and that MWe added from claimed efficiency could not be guaranteed, the value of the requirement in the specification was severely reduced and should be removed.

Source Evaluation Panel Technical evaluation comments:

1 Toshiba:Several exceptions to technical requirements, 25g tubes offered vs. 24g requested, 25g are not used in the US. Shell support design deferred to Westinghouse, material not offered for supports.
Yuba: Did not provide stress analysis for the tube sheet or a design summary as requested. They won't customize their design to fit the Columbia's configuration. An example: Sub-cooling is a standard feature whether you use it or not which could be used to add more tubes if it's not used. Their design increases risk of installation issues without a guarantee of the best back pressure (MWe gain).
TEI: Least amount of exceptions to SOW, design of module is fit around the existing shell design.

2a. All had a good performance delivery record

2b. Toshiba: Information provided was 20 years old and relies on the clad joint with perfect cladding where the weld joint takes the load.
Yuba: A pullout test can be performed at anytime in the shop. They took exception on measuring the wall thickness of 1 out of 50.
TEI: Provided a pullout test procedure but can not perform it right away. They can perform an apparent wall reduction. No exceptions taken by TEI.

2c. Toshiba: Haven't performed a retrofit of a Westinghouse design. Design is flexible to meet Energy Northwest needs.
Yuba: Yuba has designed and provided intermediate water boxes. Floating tube sheet design not flexible to changes
TEI: just performed Big Bend project because they understand the Westinghouse Design. They have not built an intermediate waterbox.

2d. All demonstrated success to a long term commitment of Condenser manufacturing

2e. Toshiba: After field visit and BAFO, the same information was provided even though revised information was requested. Toshiba does not provide a shell analysis and in the BAFO, Westinghouse is providing it. Westinghouse and Toshiba did not demonstrate seamless cooperation.
Yuba: Yuba's computer program for design is conservative and proven. Their staff doesn't appear to be as flexible to changes.
TEI has a solidworks model that can they can respond quickly to changes and demonstrated it during the field visit. They can quickly change drawings.

2f. Toshiba: Fukushima plant started up without any leaks with a new Toshiba Condenser.
Yuba: Lots of other utilities have expressed concern about Yuba's historical performance record. When asked, Yuba had two incidences of performance test they did not meet but fixed them.
TEI: Doesn't have the concern from other utilities, but did have an issue at Ft. Calhoun performance of the condenser.

3a. Toshiba: Westinghouse the middle man to Toshiba. No direct link to Toshiba and their coordination with each other needs improvement
Yuba: Technical team not as strong as TEI. Didn't know who performs stress analysis or mechanical engineering. Organization submitted in BAFO not as strong as TEI's. Project Manager was not dedicated to the Project.
TEI: Very Strong Team submitted with a dedicated Project Manager. Strong technical team and Project Management both at the shop and engineering location

3b. Toshiba: Only used two subcontractors. 1)Tube sheets 2)tubes.
Yuba: Five proposed subcontractors, Yuba did not know which subcontractors they are going to use.
TEI: Only subcontractor is a high quality tube supplier, TEI will manufacture everything else in their own shop.

3bi. Toshiba: They never provided copies of their QA/QC procedures that were requested.

Yuba: Haven't committed to using Valtimet or Ameritie as a tube supplier. Ameritie tubes are a lower cost but their quality program has issues that need to be corrected. The Project Team has both visited the Valtimet and Ameritie factories.
TEI: Has committed to using Valtimet as a tube supplier that has a strong QA program.

4a Toshiba: Quality of work very good and a clean shop. Organization of shop could use some improvement.
Yuba: Very cramped shop, feed water heaters also manufactured. Quality of workmanship better but don't know how their subcontractors perform because they wouldn't commit to who they were so EN could evaluate them.
TEI: Clean shop, lots of room, quality of workmanship could use some improvement.

4b: Toshiba: Their quality personnel could not provide information how they are involved in the manufacturing process. They don't appear to be involved with hold points.
Yuba: Quality Personnel person on site every three weeks. Also visits subcontractors. Quality Personnel didn't appear to work seamlessly with the shop. Checked tubes in the shop during visit, tubes were discovered to be scratched. They did not come back with a strategy to keep the modules clean even though they were asked during the site visit and in the BAFO.
TEI: Lots of improvement since the Columbia's feed water's manufactured. Fulltime person at Sepulpva shop, Corporate QA personnel also located in Joplin, MO close by. Tubes being manufactured in the shop were not found to be very clean during a site visit.

5a. Toshiba: Met requirement but it's based upon using 25 gauge tubes where minimum 24 gauge were specified.
Yuba: 2.36 hg", did not take credit for gains in re-heat, feedback from Technical Consultants is they are conservative in their ratings.
TEI: 2.30 hg", used 23 gauge in their calculation that is conservative. Feedback from Technical Consultants they will not be conservative in their rating.

5b. Re-heat was provided as an option 2 in Addendum 9 of the BAFO pricing sheet. The Project team determined from visiting all three vendors (between the initial proposal and the BAFO) and evaluating each vendor design, there were not guarantees of MWe gained from efficiency. As a result, the value of the requirement in the specification was severely reduced. Pam Bradley, Glen Edmonds, John LaSalle, Craig Grier, Jim Parker, Dave Tedeschi and Brian Berglin all agreed with the removal of the points for BAFO evaluation.

6a. Toshiba: Very high level 5 line schedule provided. Limited information in schedule. No subcontractors showed up on schedule.
Yuba: Detailed fabrication schedule provided. No subcontractors showed up on schedule.
TEI: Detailed fabrication schedule provided. Most detail provided.

6b. Toshiba: Delivery plan will not meet delivery schedule but will deliver in a one month time frame. Proposed delivery time was 3 months after request in BAFO.
Yuba: Will meet specified delivery schedule but over a five month period where one month was specified.
TEI: Will meet specified delivery schedule but over a two month period where one month was specified.

6c. Toshiba: Communication plan through Westinghouse for Toshiba adds risk to miscommunication. Toshiba takes has full ownership of the module it until it hits the unloading dock and turns it over Westinghouse. Not one party involved. Proposal states Westinghouse will be performing the condenser shell analysis which creates a lot of risk because they don't design condensers.
Yuba: More exceptions taken than TEI. Shop personnel concerned with Condensers in the shop. Shop is performing over its capacity. Water boxes need to be modified. Yuba does not subcontract engineering.
TEI: Least exceptions were taken by TEI. Shop is relatively new and has lots of room. Three different condenser were being manufactured at one time. All the machine work is not performed in the shop whereas the shop is a lot cleaner than Yuba's. Joplin performs all the machining and is their Joplin, MO shop keeping the particulate leveling the shop at a very low level.

7a. Toshiba: Had a separate company for Project Management.
Yuba: Did not have a dedicated Project Manager
TEI: Dedicated Project Manager at the same site with the Engineering organization. A second Project Manager was named and will be stationed at the manufactured facility.

7b. Toshiba: Communication barriers through the Westinghouse filter provides added time. A middle person creates a higher potential for technical communication errors.
Yuba: Hesitant to explain how they perform their manufacturing in detail.
TEI: TEI engineering very open to questions and provided answers when requested.

7c Toshiba: Did not commit to who would be on the Project for both Westinghouse and Toshiba.
Yuba: Did not know who exactly will be on the Project
TEI: Project personnel identified for the project which the Project team met on their visit to TEI's facilities. They also presented a Project Plan on how they would perform the Project.

8 Toshiba: Provided flow analysis and a lot of what was requested. Information was not provided for EN Engineering to validate the analysis.
Yuba: Did not provide the analysis requested. Flow analysis was not provided.
TEI: Provide most of what was requested except for Flow analysis. Also provided Engineering for lifting and rail system outside of condenser bay area.

Source Evaluation Panel Commercial Comments:

1. Toshiba: Took no exceptions to Amendment 10 but there are still lots of remaining exceptions that still need to be negotiated.
Yuba: Took minor exceptions to Amendment 10 and in general their exceptions appear to be reasonable.
TEI: Amendment 10 sent out to not take exception to these four terms. They took exceptions to 3 of 4, but the liquidated damages exceptions are difficult for us to clarify and level the field. Exceptions they did take were reasonable and well thought out.

2. Toshiba: $43.6M for 1" tubes.
Yuba: $36.9M for 7/8" tubes - $34.79M for 1" tubes - Delta = $2.13M
TEI:$36.14M for 7/8" tubes - $33.23M for 1" tubes - Delta = $2.91M

BAFO PRICING COMPARISON FOR RFP 651803 MODULE PROCUREMENT

Description	Toshiba	YUBA	TEI	
12 Modules(Ti-Clad Tubesheet and 7/8" tubes) and 3 intermediate waterboxes	Not provided	$36,156,000	$34,821,000	Toshiba:Not provided Yuba: Their base price includes a re-heat system which is their standard design TEI: Prefers to offer solid titanium tube sheets due to a bad experience with titanium cladding. Savings of using cladding is $27K.
12 Modules(Ti-Clad Tubesheet and 1" tubes) and 3 intermediate waterboxes	$49,827,000	$32,028,000	$31,068,000	Toshiba: This is the only option offered. It excludes Condensate re-heat system and sparger system. There is a $2872K savings if you select the standard 25 gauge tubing wall thickness. No one in the US has used 25 gauge tubes yet. EN Engineering advises against using 25 gauge tubes. Revised cost w/ 25 gauge tubes=$37,956,000 Yuba: Same comment as 7/8" tubes above TEI: Same comment as 7/8" tubes above
12 Modules(Titanium Tubesheet and 1" tubes) and 3 intermediate waterboxes	Not provided	Not provided	$31,995,000	Toshiba:Not provided Yuba:Not provided TEI:This price includes all the temporary and permanent support material and design.
12 Modules(Titanium Tubesheet and 7/8" tubes) and 3 intermediate waterboxes	Not provided	Not provided	$34,848,000	Toshiba:Not provided Yuba:Not provided TEI:This price includes all the temporary and permanent support material and design. At 1.8 hg/Mega Watt electric @500Megawatt input. The $2853K delta will take 8 years to recover and provide a $2.5M positive NPV at 2004 utilizing 7/8" diameter tubes
12 Modules(Ti-Clad Tubesheet and 1 1/4" tubes) and 3 intermediate waterboxes	Not provided	$30,308,000	Not provided	Toshiba: Not provided Yuba:Same comment as 7/8" tubes above. TEI:Not provided
Condensate re-heat system originally specified and provided as an option in BAFO	Not provided	Included	Not provided	Toshiba:Not part of Design Yuba: Integral part of Design and no additional cost for option. Re-heat system replaces area where tubes would be. Benefit vs. test tubes is estimated to potentially be .3 Mwe/hr gain. The risk of utilizing Yuba's design includes the recommendation of using new waterboxes or retrofitting our existing water boxes adding additional cost not yet estimated. SEP determined the risk of using this design out weighs the benefit of the MWe potential gain which cannot be guaranteed at this point. TEI: Not part of Design
3 new inlet and 3 new outlet waterboxes	$3,797,000	$1,782,000	Not provided	Toshiba: Not originally offered but particularly expensive. Yuba: Due to their design, inlet & outlet waterboxes are the least risk for Yuba and deleting them will cause EN to modify existing waterboxes and piping to adapt to Yuba's design leading to additionally costs that have not been estimated. TEI: Design is a retrofit centered around the original design which has been demonstrated at other sites. Purchasing inlet and outlet waterboxes is not needed with this design.
Provide temporary supports design and entire permanent design (inside shell) and material	$804,000	$930,000	Included	Toshiba: Did not supply all the support materials asked for in the BAFO. Attachment F, Toshiba Scope Plan item 11 requires $100,000 for the design for removal of the existing modules but not sure if this is included in the price. Westinghouse to design the rail systems inside the Condenser shell, not Toshiba. Yuba:Material not normally provided TEI:All inclusive in price
Additional manways and ladder rings being added to address current safety concerns	$339,000	$10,000	Included	Toshiba:Price includes sparger system Yuba: none TEI:Included in price
Sparger system injecting leak detection in the intermediate water boxes	?	$29,000	Included	Toshiba:Price includes sparger system and is shown with the additional manway pricing Yuba:none TEI:Included in price
1/2" thick main tube supports vs specified 5/8"	Not provided	Not provided	-$114,000	Toshiba: Did not offer alternative cost & reduction in module weight Yuba:Did not offer alternative cost and reduction in module weight TEI:Shipping cost will also be less because of reduced weight. Additional savings can be achieved but it was not offered with proposal
Provide design of the rail system outside of the condenser bay that would load the condenser modules onto a trailer for shipment.	Not provided	Not provided	Included	Toshiba:Not enough time in BAFO to supply price Yuba: Design included in offer TEI:Design included in offer
150 Control tubes and holes in the tubesheets	Included	Included	Included	Toshiba:Reduced $28,000 if 30 control tubes and holes are used Yuba:No exception TEI:No exception
Shipping	$665,000	Included	$708,000	Toshiba: inland shipping estimate only. Overseas shipping may be missing? No rate in overseas shipping included. If able to modify the Late Delivery Liquidated Damages to reflect the dates of delivery, liquidated damages could reduce price by $810,000. Yuba:Included in price? TEI:Estimated price without weight reduction utilizing 1/2"
Module Delivery time based on a one month period by July 2010. (D&I Contractor Cost baseline is also 1 month) (Cost not added to total below).	Does not meet	Does not meet	Does not meet	Toshiba:Meets the one month delivery but not until October 2010 instead of the required July 2010. Yuba:July delivery but stretched out 5 months, additional D&I cost should be added to this offer or a different delivery date negotiated to coordinate with D&I contractor currently scheduled for one month delivery. TEI:July delivery but stretched out 1 month, additional D&I cost should be added to this offer or a different delivery date negotiated to coordinate with D&I contractor currently scheduled for one month delivery.
Overseas Tariff	Included	Not required	Not required	Toshiba:Price includes 5.6% import duties Yuba:Not required TEI:Not required
Ten items in Toshiba's Attachment C of BAFO identifying increased costs that were not part of BAFO.	$1,528,000	N/A	N/A	Toshiba:Attachment F, Toshiba Scope Plan items 12, 13, 16, 17, 18, 20-2, 21, 24,26, 27, 28, 30 has $1,528,000 of additional costs associated with the procurement Yuba:None identified TEI:None identified
Subtotal 7/8" Tubes		$36,918,000	$35,434,000	
Subtotal 1" Tubes		$34,798,000	$32,881,000	
Performance Bond 7/8" tubes	Included	Included	$708,680	Toshiba: included in the price Yuba:Included in the price TEI:2% of total 7/8" tube price
Performance Bond for 1" tubes	Included	Included	$657,620	Toshiba: included in the price Yuba:Included in the price TEI:2% of total 1" tube price. $37,080 less cost than 7/8" tubes.
Total 7/8" Tubes		$38,918,000	$36,142,680	Toshiba:No bid on 7/8" tubes Yuba: Delta between 7/8" &1" tubes, $2,128,000 additional cost. Vacuum gain is .04"hg. TEI: Delta between 7/8" & 1" tubes, $2,853,000 additional cost. Vacuum gain is .08"hg. 8 years to NPV=0. NPV@2024=$2088K per Asset Management Chris Indell.
Total 1" Tubes	$43,016,000	$36,146,000	$33,539,000	Toshiba:Cost is out of range and significantly greater than other competitors. Yuba: Less cost than 7/8" diameter tubes TEI: Least total cost, performance bond waived on lower price to an additional $67,000. Maximum savings was based on $3,800,000 additional cost. $3,800,000 - $67,000 = $3,733,000.
Total 1 1/8" Tubes	Not an option	$31,378,000	Not an option	Yuba: Least total cost. Not a feasible option to be considered because of back pressure at 2.46" hg whereas the spec and business case was based on 12 Mwe at 2.41"hg back pressure.
Delta between 7/8" and 1" Titanium Tubes		$2,128,000	$2,918,000	

Yellow-used in figuring price
Orange-questionable items that need answers
Red-concerns
Green-recommended comparible selected options
Orange-delta of 7/8" tubes vs. 1" tubes

Notes:

1.TEI has a one piece waterbox that can be fit up in the shop ahead of time. They will split the waterbox if they need to. They haven't installed a new intermediate waterbox before. They have just performed the Big Bend Project on a like design.
2.Yuba has a split intermediate water box design. They have used this split design before and been successful.
3.Yuba provides no coating for the waterboxes. TEI does.
4.Yuba supplies the re-heat system for the modules no matter if we use it or not.
5.Extensive modification to the existing inlet and outlet waterboxes must be performed with Yuba. Yuba's price comparison includes installing new waterboxes to reduce the risk.
6.TEI can stack the modules and fit the intermediate waterboxes in the shop before shipment to assure alignment
7.Yuba's design requires internal supports inside the waterboxes, whereas TEI's does not require it.
8.Yuba did not supply the stress analysis documents
9.Yuba did not provide historical tube results requested in the Specification
10.TEI did not provide a re-heat design system

ENERGY NORTHWEST

INTEROFFICE MEMO

DATE: August 26, 2008

TO: S. K. Gambhir, Vice President, Technical Services

FROM: J. V. Parrish, Chief Executive Officer

SUBJECT: MAIN CONDENSER REPLACEMENT PROJECT PROCUREMENTS

REFERENCE: CONTSEG, Source Evaluation Guidelines, September 2000

On April 28, 2008, a memo was issued assigning you as the Source Selection Official (SSO) and appointing a Source Evaluation Panel and Contract Review Board for the two primary procurements supporting Columbia Generating Station's Main Condenser Replacement Project. The first procurement is for the fabrication and delivery of twelve condenser modular bundles and three intermediate waterboxes; the second procurement is for associated design and installation services. On July 10, 2008, a memorandum was issued revising the composition of the Contract Review Board and Source Evaluation Panel.

As a result of recent staffing changes and the need for backup support, the membership of the Source Evaluation Panel has again changed. Accordingly, the appointment memo is revised to reflect the changes to the Source Evaluation Panel membership as shown below:

Source Evaluation Panel

Chairman:	B.G. Berglin, Condenser Project Manager
Members:	C.L. Grier, Condenser Project Cognizant Engineer
	J.R. Lasalle, Pr. Engineer
	D.R. Senner, Quality Supervisor
	D.A. Swank, Manager Projects
	L.W. Syverson, Quality Auditor II - NDE
	K.A. Whelan/G. Edmonds, Pr. Contracting Officers
	L.J. Woods, Sr. Engineer
Recorder:	Donna Sylvester, Administrative Assistant
Advisors:	R. Bayer, Independent Contractor
	P.R. Bradley, Assistant General Counsel
	J.W. Dabney, Maintenance Component Group Manager
	D.A. Garza, Condenser Project HP Coordinator
	R.S. Korenko, Independent Contractor
	L.D. Morrison, Chemistry Specialist

J.E. Parker, Independent Contractor
A.D. Rains, Staff Attorney
D. Tedeschi, Independent Contractor

Contract Review Board

Chairman: L.A. Pagel, Manager, Supply Chain Services
Members: D.K. Atkinson, VP, Nuclear Generation
J.E. Bekhazi, Planning/Scheduling Outage Manager
A.E. Mouncer, VP Corporate Services/CFO

kaw

ENERGY NORTHWEST

Condenser Replacement Project Steering Committee Meeting

Project No. 00608601

October 14, 2008

Brian Berglin

Agenda

Safety	5 min
Module Procurement Update	15 min
Transferred Costs	15 min
Disposal Cost	10 min
Design & Install Contract Update	20 min
Break	5 min
Design & Install Alternatives	15 min
Project Information Updates	5 min
Action Items from 09-22-08 Mtg	10 min
Round table & Meeting Actions	15 min
Meeting Effectiveness	5 min

Contract Procurement Status

Activity	Estimated Dates	
	Module	Installer
Issue Request of Proposal	Complete	Complete
Pre-bid Conference	Complete	Complete
Proposals Due	Complete	Complete
Visit Vendors	Complete	
Offeror's Presentations		Complete
Issue Best & Final Offer	Complete	Complete
Best & Final Offer Received	Complete	Complete
Steering Committee Review	10-14-08	10-14-08
Contract Review Board	10-15-08	10-15-08
Executive Board Presentation	10-22-08	10-22-08
Contract Execution	**10-30-08**	**11-30-08**

Module Scope -12 Modules w/ requested delivery in 07-2010

Installer Scope - R-19 Implementation, R-20 Pre-outage Design & Install, R-20 Implementation. Mobilization 11-30-08 following Contract Execution.

Module Procurement Status

Toshiba

- Did not meet specification technical requirements
- Took exceptions to terms and conditions
- 25 gauge tubes vs. 24 gauge requested
- 7/8” tubes not available
- Additional $1528K of increased cost identified that is not in bid
- Toshiba appears to only want to design modules & water boxes, Westinghouse to design the removal and installation transport system at an additional cost.

Module Procurement Status (Cont)

- Yuba
  - Standard Yuba re-heat system for sub cooling does not guarantee thermal cycle efficiency improvement
  - Backpressure ratings not as good as TEI's
  - Existing inlet & outlet water boxes will have to be modified to work with their design. Yuba strongly recommends, and EN agrees, that new water boxes are needed at $1.8M.
  - Sparger leak detection in intermediate water box and additional man ways and ladders -$30K
  - Titanium clad tube sheets are standard

Module Procurement Status (Cont)

- TEI
  - Solid titanium tube sheets standard ($27K less for clad)
  - Price includes design of all supports in condenser shell and material
  - Additional water box “B” man ways and ladders for safety provided
  - Savings of $114K using ½” thick main tube supports vs. requested 5/8”
  - Provides lifting and rigging design outside of Condenser shell
  - Most experienced/knowledgeable Engineering staff
  - Use of existing inlet and outlet water boxes
- SEP Recommendations – need CRB approval
  - TEI 1st technically and financially
  - Yuba 2nd technically and financially
  - Toshiba 3rd technically and financially

Transferred Costs

- Costs Transferred to Energy Northwest in Best and Final Offer request for revised Design & Installation Contract
  - Protected Area access upgrades $1000K
  - Facilities $2373K
  - Disposal $7000K
  - Total $10373K

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Disposal Cost

- Long Range Plan Disposal Cost of $7000K includes:
  - R-19 debris
  - R-20 debris
  - 12 modules
- In-progress Tasks
  - Chemistry identifying more specific cost for disposal
  - Energy Business Services performing study to determine if they can take ownership of the removed modules and provide a profitable Business Venture
- Near Term Tasks
  - Assign a project lead to identify all possible alternatives
  - Re-evaluate module removal method once module vendor is determined
  - Identify least cost option to dispose of existing modules

Design & Installation Contract Update

- Source Evaluation Panel's Evaluation of BAFO's Complete
- Kiewit-Day Zimmerman
  - Lowest bid received
  - Bid reduced by 26% from initial bid
  - Good relationship with partner and subcontractors
  - 65 day breaker-to-breaker schedule submitted
- Westinghouse
  - Highest bid received
  - Bid reduced by 11% from initial bid
  - Subcontractors not fully engaged
  - 65 day breaker-to-breaker schedule submitted

Design & Installation Contract Update

- Bids are too high to award full scope of contract
- Engineering cost excessive
  - No one complied with BAFO request to separate out Engineering performed by Module Vendor in Condenser Shell
  - Areva (Sub to KDZ) cost to complete Engineering-$9.3M
  - S&L/WEC cost to complete Engineering-$11.4M
  - SEP's recommendation for Engineering
    - Remove Engineering from D&I scope of work
    - Perform Engineering with Site Preferred A&E
    - Supplement with augmented staff engineering as needed
- RFP allows delaying full award of the Cycle 20 & R-20 work until post R-19.
  - R-19 construction work to be performed by SSC
  - Partner with EN and module vendor in identifying R-20 scope and provide revised estimate to complete the R-20 work.

Alternatives to maintain LRP

Goal: Achieve Board approval to award module contract and describe strategy for how the Project is maintaining costs within the Long Range Plan:

- SEP recommendation to SSO of path forward for Module and Design & Installation Contract – Complete
- Steering Committee update of recommended path forward – 10/14/08
- CRB review Module and Design & Installation Contract evaluations and obtain agreement of the path forward. -10/15/08
- Estimate of R-19 scope of work by Site Support Contractor – 10/20/08
- Estimate R-19 design support work for R-19 FCRs and Outage Support - 10/20/08
- Perform estimate of remaining $ for Cycle 20 thru Cycle 21 work utilizing SSC R-19 estimate – 10/21/08
- Decision on path forward from Senior Management – 10/21/08
- Notify contractors and vendors of selection decisions – 10/21/08

Alternatives to maintain LRP (cont)

- Initiate discussions with module vendor for installation and removal work scope - 10/21/08
- Obtain Executive Board Approval of module vendor – 10/22/08
- Brief Executive Board on path forward for D&I work – 10/22/08
- Issue contract award to winning module contractor – 10/30/08
  - Initiate design work for R&R activities
  - Review Performance Monitoring and agree on minimum scope needed for warranty
- Obtain Executive Board Approval of installation contractor – 11/20/08
- Award contract to proceed to winning installation contractor – 11/30/08
  - Work with module vendor to define most efficient way to R&R modules
  - Limited scope – scoping and estimating for Cycle 20 and R-20 work
  - Perform estimate of Cycle 20 & R-20 scope –7/30/09

Alternatives to maintain LRP (cont)

- Issue R-19 PDCs (S&L/WEC – already in progress) – 12/18/08
- Investigate site preferred A/Es to perform Cycle 20 & R-20 design engineering work. – 11/14/08
- Contract release SSC to perform R-19 work. – 11/14/08
- Complete R-19 Work Order Planning – 02/12/09

Project Information Updates

- 70% Design Review for R-19 Performance Monitoring Instrumentation (PDC 6692) did not meet 09-30-08 due date. Project has reduced scope of work but revised schedule and estimate have not been received from WEC as requested.
- 70% Design review for Condenser Travel Path Interference inside TGB (PDC 6693) - Complete
- 70% Design for R-19 Condenser Mods to support rail system support & access (PDC 6834) –Complete
- R-19 Outage Project Work Orders are 22% planned.

ACTION ITEMS FROM 09-22-08 MTG

AIL#	Description	Assign	Expected	Rev.	Open	Closed	Group	Responsible
616	Produce a chart to be posted showing activities in P6 schedule	7/28/08	10/9/08	1		X	SC	Berglin/Jordan
623	Develop tools for tracking budget and schedule compliance	7/28/08	10/14/08	2	X		SC	Ridge
659	Provide estimate total Project cost (R-19 plus R-20) and separate design (R-19 and R-20) cost which includes the install cost, full disclosure	9/22/08	10/14/08			X	SC	Berglin
661	Review Laguna Verde benchmark trip in next Steering Committee Mtg	9/22/08	11/17/08	1	X		SC	Berglin
662	Reconfirm w/Dave Kania regarding chemistry is involved with US Ecology disposal of Modules	9/22/08	10/14/08			X	SC	Berglin
664	Review Business Case & LRP with Impacts on LRP spreadsheet, provide comparison and details.	9/22/08	10/14/08			X	SC	Berglin
665	Provide Status schedule to management	9/22/08	10/14/08			X	SC	Jordan
676	Action: Brian Berglin to proceed forward with obtaining a R-19 bid from the current Site Support Contractor	9/22/08	10/14/08			X	SC	Berglin

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Key Take Aways

- Project NPV remains within Business Case
- R-19 Design Engineering on schedule
- Modules on schedule and budget
- Alternative methods being investigated due to high Design & Installation bids
- D&I Contractors reduced R-20 outage to 65 days – no specifics provided

Round Table

- Open Discussion
- Summarize Actions
- Closing Comments
- Meeting Effectiveness

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Condenser Replacement Project
Module Fabrication Procurement

Action Memorandum 1079

October 22, 2008

Brian Berglin

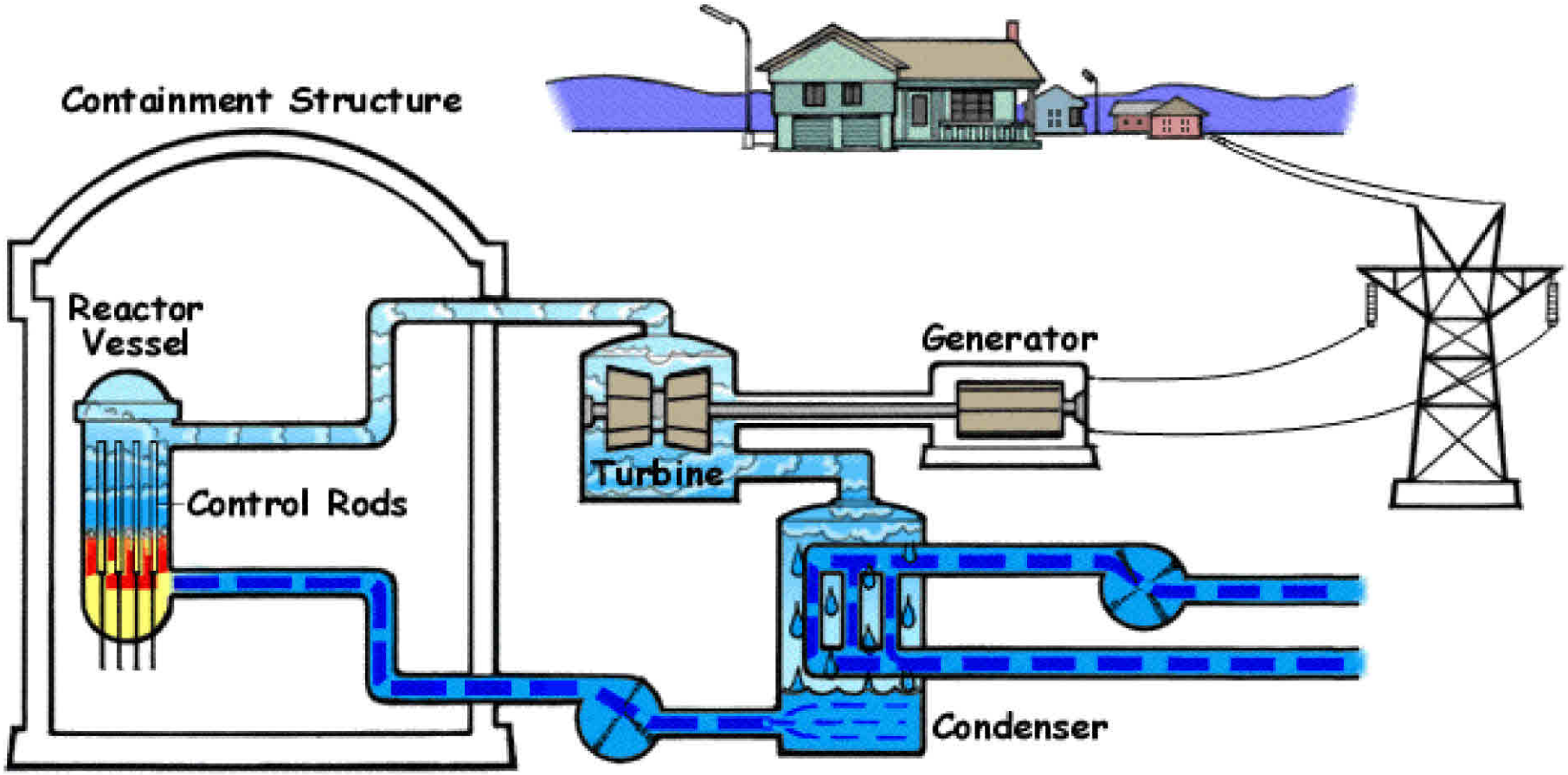
BACKGROUND

- Condenser Replacement Project split into two principal segments:
  - Design, fabrication and delivery of 12 ea replacement condenser modules (Request for Proposal (RFP) 651803)
  - Performance of tasks necessary to remove the existing condenser modules and installation of new condenser modules (RFP 651804)
- This Action Memo only addresses Module Fabrication
- RFP 651803 was issued on 05-23-08

BACKGROUND (continued)

- Initial bids received on 08-06-08
  - Thermal Engineering International (TEI)
  - Yuba Heat Transfer
  - Toshiba (Westinghouse)
- Project team performed plant site visits to all vendors and main sub-contractors
- Best and Final Offer issued on 09-29-08

BWR Steam Cycle



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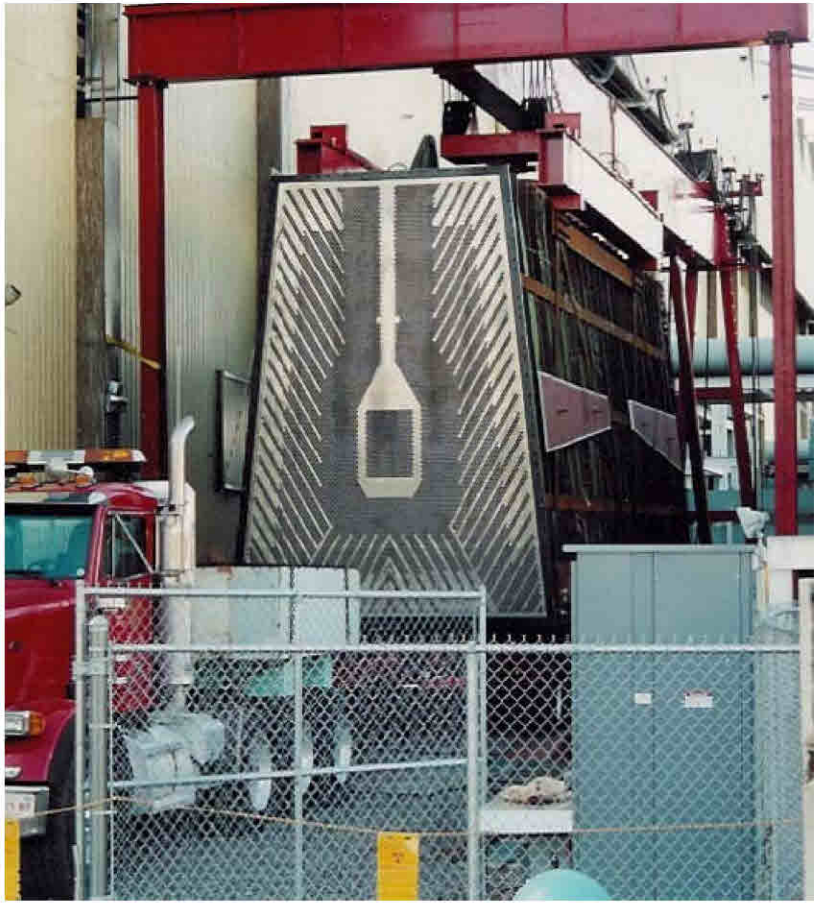
Condenser Module Description (12 ea)

DESCRIPTION	EXISTING	PROPOSED
Surface Area	66,000 ft^2 (792,000 total)	Increased
Tube Material	Admiralty Brass	Titanium
Number of Tubes	4053 (48,636 total)	7166 (86,000 total)
Tube Length	50 feet	50 feet
Tube outside diameter	1-1/4 inches	7/8 inches
Design cleanliness factor	85% (actual 53%)	85%
Width	10 feet	10 feet
Height	12 feet	12 feet
Weight	220,000 pounds	180,000 pounds

One Main Condenser Module



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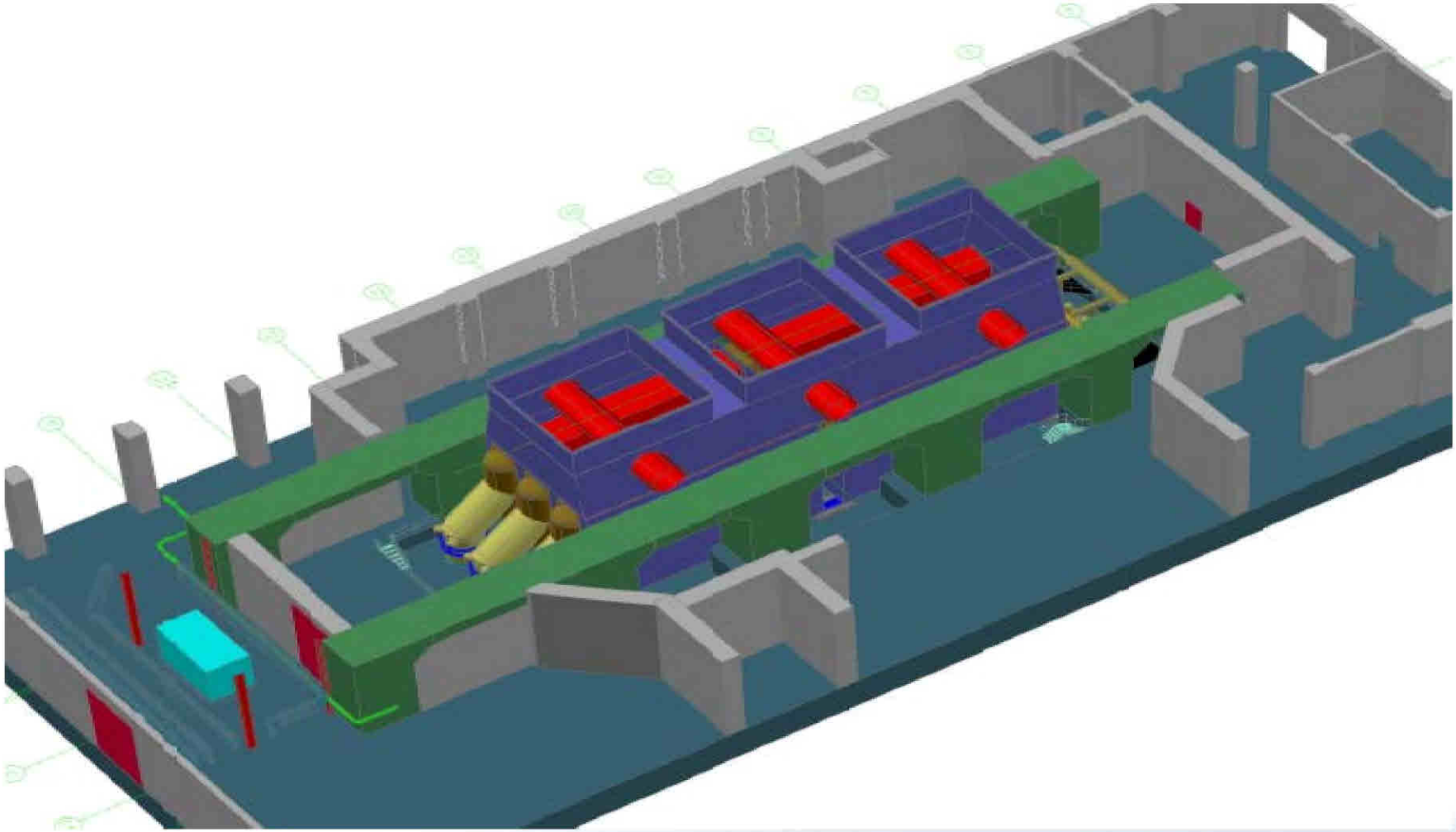
Main Condenser Project: 3D overview



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Discussion

- Best and Final Offers received on 10-09-08
- Reviewed by Source Evaluation Panel using weighted criteria
- TEI ranked to be the most advantageous both technically and the lowest cost
- Recommendation reviewed and approved by Contract Review Board on 10-15-08

Discussion (cont)

- Award of this contract will assist the Project team in:
  - Eliminating current design unknowns
  - Clarifying installation scope of work tasks needed

Discussion (cont)-module being removed

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Discussion (cont)-condenser interior shell

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Discussion (cont)

- Bids received were
  - TEI-$36.1M
  - Yuba-$36.9M
  - Toshiba-43.6M
- Estimates made on:
  - Performance Bond
  - Shipping

Recommendation

- Award Main Condenser Module Design, Fabrication and delivery RFP 651803 to TEI for $37,000,000.

Meeting Minutes
Steering Committee – Condenser Replacement Team
Project # 00608601

Date: October 14, 2008
Time: 11:30 am - 1:30 pm

Safety Moment: Siding for building will be coming in on Monday. Be aware of increase crane work. Also, Standard Time begins Nov 2nd, watch for the grazing and feeding of deer and other wildlife as the time change takes effect.

Handouts: Agenda, Sign in sheet

The confidentiality of subject and materials covered in this meeting were reviewed. Members in attendance who did not have a Confidentiality Agreement on file, signed on 10-14-08.

1. **Reviewed Module Procurement status**
   a) Compared Toshiba, Yuba, TEI Vendor bids technically and financially.
   b) Source Evaluation Panel recommends TEI 1st, Yuba 2nd and Toshiba. Need CRB approval, CRB Meeting scheduled 10-15-08.
   c) Transfer costs reviewed included protected area upgrades, facility and disposal costs.
   d) Disposal costs: LRP Long Range Plan Disposal Cost of $7000K which includes, R-19 debris, R-20 debris, and 12 modules.
   e) The urgency of awarding the module procurement is to ensure the Project team can obtain the design of the stiffening condenser shell and install as many supports as possible during R-19 outage to shorten the R-20 outage duration.

2. **Review Design and Installation Proposal**
   a) Source Evaluation Panel's Evaluation of BAFO's Complete
   b) Both KDZ and Westinghouse bids were higher than the approved project funding. The bids were too high to award full scope of contract.
   c) Westinghouse reduced their bid by 11%, KDZ by 26%, KDZ was the selected winner over Westinghouse by the Source Evaluation Panel.

3. **Alternatives To Maintain Project Long Range Plan budget**
   a) CRB review Module and Design & Installation Contract evaluations and obtain agreement of the path forward. -10/15/08
   b) Estimate of R-19 scope of work by Site Support Contractor – 10/20/08
   c) Estimate R-19 design support work for R-19 FCRs and Outage Support - 10/20/08
   d) Perform estimate of remaining $ for Cycle 20 thru Cycle 21 work utilizing SSC R-19 estimate – 10/21/08
   e) Decision on path forward from Senior Management – 10/21/08
   f) Notify contractors and vendors of selection decisions – 10/21/08
   g) Initiate discussions with module vendor for installation and removal work scope - 10/21/08
   h) Obtain Executive Board Approval of module vendor – 10/22/08
   i) Brief Executive Board on path forward for D&I work – 10/22/08

j) Issue contract award to winning module contractor – 10/30/08
k) Obtain Executive Board Approval of installation contractor if needed – 11/20/08
l) Award contract to proceed to winning installation contractor – 11/30/08
m) Issue R-19 PDCs (S&L/WEC – already in progress) – 12/18/08
n) Investigate site preferred A/Es to perform Cycle 20 & R-20 design engineering work. – 11/14/08
o) Contract release SSC to perform R-19 work. – 11/30/08
p) Complete R-19 Work Order Planning – 02/12/09

4. **Project Information Updates**
   a) 70% Design for R-19 Performance Monitoring Instrumentation (PDC 6692) from WEC did not meet 09-30-08 due date. Project has reduced scope of work but revised schedule and estimate have not been received from WEC as requested. Finalizing the instrumentation will be complete when the independent consultants, selected module vendor and EN Engineering agree on the minimum amount of instruments needed for performance monitoring.
   b) 70% Design for Condenser Travel Path Interference inside TGB (PDC 6693) by Sargent and Lundy has been submitted but was not complete. EN Engineering does not know when the final calculations and drawings will arrive for review. CR's have been written and the issues are being addressed.
   c) 70% Design for R-19 Condenser Mods to support rail system support & access (PDC 6834) has been submitted to EN for review by Sargent and Lundy.
   d) R-19 Outage Project Work Orders are 22% planned.

5. **Action Items Reviewed from Last Steering Committee held 9-22-08**
   a) AIL# 661,review Laguna Verde benchmark trip has been carried forward to 11-17-08.
   b) AIL# 676, obtain R-19 bid from the current Site Support Contractor has been carried forward to 10-20-08.

6. **Key Takaways**
   a) Project NPV remains within Business Case
   b) R-19 Design Engineering on schedule
   c) Modules on schedule and budget
   d) Alternative methods being investigated due to high Design & Installation bids
   e) D&I Contractors reduced R-20 outage to 65 days – no specifics provided

7. **Action Items resulting from this meeting:**
   a) Re-Confirm Module Vendor stability/solvency, bond and financial statement. Glen Edmonds due date 10-20-08 AIL#794
   b) Obtain additional information for EAC/Sr Management Meeting scheduled for 10-21-08 clear justification, LRP and contingency. Brent Ridge/Dave Jordan/Brian Berglin, due date 10-21-08 AIL# 795
   c) Provide findings of fact for BPA Non-disapproval letter for the Condenser Module procurement. Glen Edmonds due date 10-20-08 AIL# 796
   d) Obtain full disposal cost from US Ecology. Jim Homan due date 11-17-08 AIL#797

e) The two carry over AIL's # 661 and #676 from last months meeting.

Condenser Replacement Project Steering Committee Meeting Attendance				
Name	**Title**	**Attended**	**Signature**	**Notes**
Atkinson, Dale	VP Nuclear Generation	✓		
Bekhazi, John	Planning/Scheduling Outage Mgr	✓		
Berglin, Brian	Condenser Project Mgr			
Frisco, Joe	Engineering General Mgr			
Gambhir, Sudesh	VP Tech Services			
Jenkins, Brad	C&MS Mgr			
Pagel. Lynne	Supply Chain Mgr			
Rapacz, Andy	BPA Contracts Generation Mgr	✓		
Ridge, Brent	Asset Mgr/Controller	✓		
Smathers, Verdon	Condenser Project Admin			
Swank, Dave	Engineering Projects Mgr			
Reed, Mark		✓		
Sherman, Bob	BPA	✓		
Glenn Edmonds	EN	✓		

From: Smith,Phil - PGC-RICHLAND
Sent: Monday, November 10, 2008 2:08 PM
To: Carlson,Debbie - PGC-RICHLAND
Subject: include this attachment #1

Attachments: 10-14-08 Steering Committee presentation.ppt

From: Berglin, Brian G. [mailto:BGBERGLIN@energy-northwest.com]
Sent: Friday, October 17, 2008 8:22 AM
To: Rapacz, Andrew J.; Smith, Phillip E.; Smith,Phil - PGC-RICHLAND
Cc: Edmonds, Wilbur G.; Swank, David A.; Gambhir, Sudesh; Hogue, Ronald W.
Subject: Requested Information for Condenser Procurement

Below is the list of requested information to make sure BPA has all of the information needed to write the non disapproval letter and obtain approved asap in regards to the upcoming procurement of the condenser modules.

1. 10-14-08 Steering Committee presentation (attached)
2. Action Memorandum 1079 -Glen Edmonds
3. Findings of Facts - Glen Edmonds
4. 10-22-08 Executive Board Presentations - Brian Berglin

Items 2-4 will be sent upon completion and approval of the documents.

Thanks for your insight and understanding of the urgency.
Brian

From: Smith,Phil - PGC-RICHLAND
Sent: Monday, November 10, 2008 2:08 PM
To: Carlson,Debbie - PGC-RICHLAND
Subject: include attachment #2

Attachments: 10-22-08 Action Memo 1079 - Module Procurement.ppt

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From: Smathers, Verdon M. [mailto:vmsmathers@energy-northwest.com]
Sent: Friday, October 24, 2008 2:43 PM
To: Smith, Phillip E.; Rapacz, Andrew J.; Smith,Phil - PGC-RICHLAND
Cc: Berglin, Brian G.
Subject: Action memo

As per Brian's instructions, attached is the action memo 1079.
Have a great day.

From: Smith,Phil - PGC-RICHLAND
Sent: Monday, November 10, 2008 2:13 PM
To: Carlson,Debbie - PGC-RICHLAND
Subject: include attachment #4

Attachments: 10-14-08 Steering committee minutes .doc

From: Smathers, Verdon M. [mailto:vmsmathers@energy-northwest.com]
Sent: Monday, November 03, 2008 1:31 PM
To: Rapacz,Andy - PGC-RICHLAND; Atkinson, Dale K.; Bekhazi, John E.; Berglin, Brian G.; Deery, Danielle J.; Demyer, Tanya M.; Dixon, Deborah J.; Dugan, Cassandra S.; Fleming, Dyana R.; Frisco Jr, Joseph M.; Gambhir, Sudesh; Hoyle, Brian C.; Jenkins, Bradley Y.; Lynch, Thomas A.; Magill, Jessica E.; Martin, Sandra J.; Myers, Zeny; Pagel, Lynne A.; Smith,Phil - PGC-RICHLAND; Rapacz, Andrew J.; Richey, Sybil A.; Ridge, Brent; Smathers, Verdon M.; Swank, David A.; Thrun, Lori A.; Vogel, Desiree
Subject: steering committee minutes from meeting on 10-14-08

Good day, attached are the minutes from the Steering Meeting held 10-14-08 for your review. Please accept our apologies for the delay in getting these minutes out to all, we were experiencing competing high priority items.
If there are any questions about the meeting minutes, please contact myself and Brian Berglin.

Thank you,

Verdon Smathers
Condenser Replacement Project
Administration
P: 509-377-4768

Department of Energy

Bonneville Power Administration
Mail Drop 1399
P.O. Box 968
Richland, Washington 99352-0968

POWER SERVICES

November 23, 2009

In reply refer to: PGC/Richland

Mr. S. K. Gambhir, Vice President
Technical Services
Energy Northwest M/D PE04
P. O. Box 968
Richland, WA 99352-0968

Dear Mr. Gambhir:

In reference to your letter "Energy Northwest RFP 655678 R-20 Condenser Installation Contract" dated November 13, 2009, and received on November 23, 2009, the Bonneville Power Administration (BPA) does not disapprove execution of the proposed contract action.

The proposed action would authorize Energy Northwest to execute a contract in response to RFP 655678, with Babcock & Wilcox Nuclear Power Generation Group, Inc. in an amount not to exceed $32,845,734.00 for the removal of the existing twelve main condenser modules and installation of the new condenser modules as part of the Main Condenser Replacement Project, which is planned for execution during the R-20 (2011) Refueling Outage.

We wish to acknowledge Energy Northwest's efforts to keep BPA informed during the contractor selection process through BPA's participation in the condenser steering committee meetings and additional briefings on the work of the source selection panel. We commend the source selection panel for the quality and professionalism of their work during this procurement process.

Sincerely,

Andrew J. Rapacz, Manager
Contract Generating Resources

cc:
Mr. Brian G. Berglin, Energy Northwest - 964F
Ms. Lynne A. Pagel, Energy Northwest - PE10

Assumptions for condenser upgrade project applicable to retube or rebundle the condenser

Material choices

Retube the condenser with copper tubing.

- Retubing the condenser with copper is not a viable option unless a deep bed demineralizer is added to the station. The existing condenser can be retubed with copper tubing with nearly the same costs and impact as other retubing materials. The deep bed demineralizer will remove the copper in the feed water, but create radwaste issues for the plant. Cost for the deep bed demineralizer is in the $20 to 30 million dollar range.

- The existing condenser with the brass tubing adds soluble and insoluble copper to the reactor water. The Noble metals and hydrogen addition to the reactor causes the copper in the reactor water to plate out on the reactor surfaces. The presence of significant amounts of copper constitutes a substantial increase in the risk of fuel failure should a fuel corrosion event occur.

- Retube the condenser with the following stainless steel tubing materials is not recommended.

- 304 or 316SS are susceptible to MIC and under deposit pitting. During shutdowns operations needs to perform waterside lay-up procedures. The impact to plant operations during forced and planned outages along with the risk of initiating corrosion due to poor or lack of water side lay-up removed these materials from consideration.

- Type 439SS has a pit type and crevice corrosion resistance less than type 304, has a greater potential for brittle behavior, and may have greater potential for galvanic corrosion with a less noble tube sheet.

- AL-6XN is not a material of choice, given the availability of cheaper materials of comparable corrosion resistance and better thermal performance.

Retube the condenser with the following materials that are recommended and can be further evaluated.

- Super Ferritic SS, which includes AL-29-4C, Allegheny Ludlum Corporation, and Sea-Cure, Plymouth Tube Company, are desirable condenser retubing materials. The Sea-Cure is superior to the AL-29-4C due to Sea-Cure's, lower ductile to brittle transition temperatures, higher toughness, and superior corrosion resistance.

- Titanium has proven to be one of the most reliable tubing materials in surface condenser applications and has extensive operating history in domestic nuclear plants.

Material choice conclusion

The materials of choice are narrowed to Super Ferritic SS, Sea-Cure or Titanium for retubing or rebundling the main condenser. The US Nuclear fleet of 104 reactors, 43 have titanium tube condensers, 7 have Sea-Cure SS tubing and 25 use 304/316 series SS. The remaining plants use various materials. Titanium has been the overwhelming choice. 24 gauge tubing is only suitable for shop fabrication of modules. The tubing is easily damaged during handling and is difficult to roll a leak tight joint in a muntz metal tube sheet. 22 gauge tubing is acceptable for retubing with a muntz metal tube sheet. Rebundling the condenser with 22 gauge titanium or 22 gauge Sea-Cure is recommended since FME resistance is a prime factor in replacing the tubing.

Other factors that need to be incorporated into the cost evaluation of the retubing or rebundling of the condenser are as follows;

Eddy current testing, ECT, is more expensive with Sea-Cure due to probe wear and difficulty with reading the ECT data at the support. ECT of titanium tubing is straight forward and the data is easily interpreted. Either tubing would be specified with NDE acceptance criteria that would assure the tubing is essentially defect free. 100% baseline must be performed after installation. A 10% ECT of the condenser would be performed each outage. Initial tube plugging would be at a very low rate.

Galvanic Corrosion is caused by the galvanic couple between the muntz metal tube sheet and the tube material that is higher in the galvanic series. The alloy that is lower in the galvanic series would preferentially corrode and would be accentuated if a crevice is formed between the alloys. Cathodic protection can be provided in the form of impressed current or sacrificial anodes. An impracticable number of sacrificial anodes would be needed. The impressed current system must be selected with care and controlled carefully. Over voltage can result in embrittlement of these alloys and can occur in days if the over voltage is not corrected. For the retubing option a thick film epoxy coating is required on the water box side. The coating has been shown to eliminate tube to tube sheet leaks and increase the pull out strength of rolled tube to tube sheet joints. The coating

Tube vibration assessment by Sargent and Lundy, suggests that the spacing between tube supports is adequate to prevent flow induced vibration, FIV. FIV is minimized through adequate support spacing. A refined tube vibration assessment is recommended if retubing with titanium is selected. The refined assessment may require staking for titanium tubes. The titanium retubing cost comparison does include tube

staking since the Sargent and Lundy assessment indicated staking was required by the conservative HEI method. The added cost for staking was $550,000.

The ALARA estimate for working at the condenser performing retubing or bundle replacement would be based on .2 to .4 mR/hr. The evaluated cost for an avoided man Rem is $25,000.

If a shell hydro test of the condenser is required to assure the tube to tube sheet joints are leak free, a water management plan needs to be developed. Sufficient water can be made in three days and cleanup time for water disposal is 10 days. Clean up rate is 60,000 gallons/day. This evaluation assumes a successful water management plan is implemented to eliminate the schedule delay of making water and cleanup for disposal. A condenser shell hydro is only required for retubing. For bundle replacement, testing is done in the shop. A surface exam and vacuum leak tests are performed.

Schedule milestones for condenser retubing (assume implementation Spring 2009) dates have minimum float.

Management approval of project	94 weeks
Start Project team meetings	90 weeks
Start PDC design change package and tube specification	85 weeks
Start Turnkey retubing specification	70 weeks
Complete PDC package	65 weeks
Complete Turnkey retubing specification	62 weeks
Condenser tube specification ready to bid	61 weeks
Condenser bids received and ready to evaluate	57 weeks
Turnkey specification for retubing contractor issued to bidders	56 weeks
Board info memo on condenser tubing contract award	56 weeks
Board action memo on condenser tubing contract award	52 weeks
PO issued for condenser tubing	51 weeks
Board info memo on condenser retubing contract award	47 weeks
Bids due from retubing contractors	50 weeks
Board action memo on condenser retubing contract award	43 weeks
Award turn key retubing contract	42 weeks
1/3 tubes on delivered on site	31 weeks
Retubing contractor start mobilization on site	28 weeks
Retubing contractor trailer on site	20 weeks
Procedures and ALARA plan developed	18 weeks
Final shipment of condenser tubing on site	12 weeks
Procedures and ALARA plan approved	6 weeks
Waste handling mobilization complete	4 weeks
Mobilization complete for labor, supervision and Project team	2 weeks
Start condenser outage	0 weeks
Condenser retubing complete testing begins	-10 weeks
Condenser retubing testing complete	-11 weeks
Condenser returned to operations	-11 weeks

Schedule milestones for condenser rebundling (assume implementation Spring 2009) dates have minimum float.

Management approval of project	134 weeks
Start Project team meetings	133 weeks
Start PDC design change package and tube specification	130 weeks
Start Turnkey rebundle specification build and construct	130 weeks
Complete PDC package and tube specification	120weeks
Complete turnkey rebundling specification	120 weeks
Tube Specification out to bid	118 weeks
Condenser rebundle specification ready to bid	118 weeks
Condenser rebundle bids received and ready to evaluate	112 weeks
Condenser tube bids received and ready to evaluate	112 weeks
Board info memo on condenser rebundle contract award	111 weeks
Board info memo on tube contract award	111 weeks
Board action memo on condenser rebundle contract award	107 weeks
Board action memo on condenser tube contract award	107weeks
PO issued to condenser rebundle contractor	106 weeks
Plant walk down and post award meeting with rebundle contractor	104 weeks
Rebundle contractor submits project work schedule and work plan	94 weeks
Rebundle contractor submits drawing package for info and approval	90 weeks
Drawing package status approved	85 weeks
Start on design change package for rebundle effort	80 weeks
Order material for condenser bundles	80 weeks
Drill tube sheets	75 weeks
Complete design package for rebundle effort	60 weeks
Approve rigging plan from the rebundle contractor	42 weeks
Decontamination plan approved	31 weeks
Retubing contractor start mobilization on site	28 weeks
Retubing contractor trailer on site	20 weeks
Procedures and ALARA plan developed	18 weeks
Final shipment of condenser modules on site	12 weeks
Procedures and ALARA plan approved	6 weeks
Waste handling mobilization complete	4 weeks
Mobilization complete for labor, supervision and Project team	2 weeks
Start condenser outage	0 weeks
Condenser rebundle complete	-17 weeks
Condenser returned to operations	-17 weeks

ENERGY NORTHWEST

Condenser Replacement Project
Module Fabrication Procurement

Action Memorandum 1079

October 22, 2008

Brian Berglin

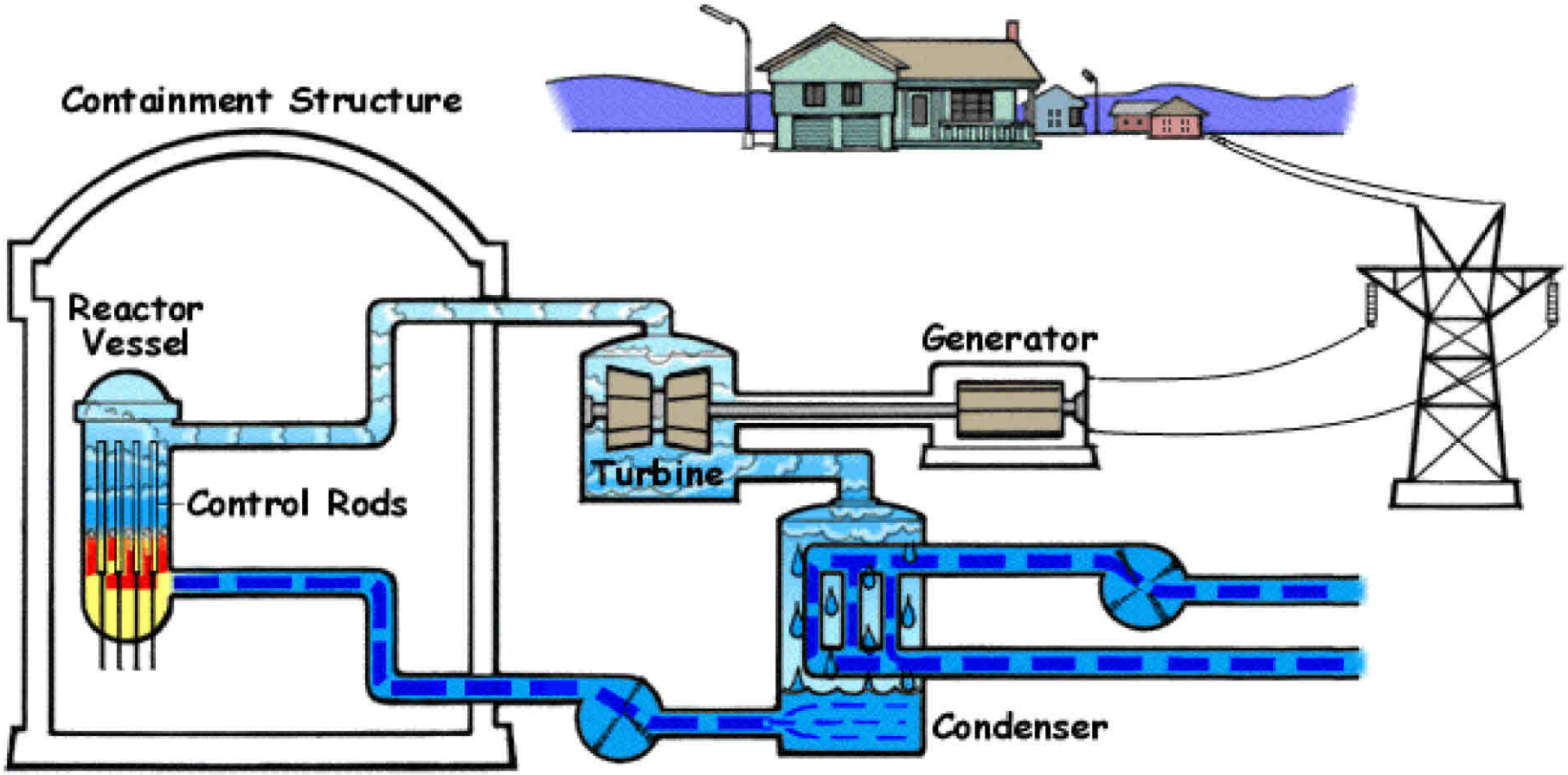
BACKGROUND

- Condenser Replacement Project split into two principal segments:
  - Design, fabrication and delivery of 12 ea replacement condenser modules (Request for Proposal (RFP) 651803)
  - Performance of tasks necessary to remove the existing condenser modules and installation of new condenser modules (RFP 651804)
- This Action Memo only addresses Module Fabrication
- RFP 651803 was issued on 05-23-08

BACKGROUND (continued)

- Initial bids received on 08-06-08
  - Thermal Engineering International (TEI)
  - Yuba Heat Transfer
  - Toshiba (Westinghouse)
- Project team performed plant site visits to all vendors and main sub-contractors
- Best and Final Offer issued on 09-29-08

BWR Steam Cycle



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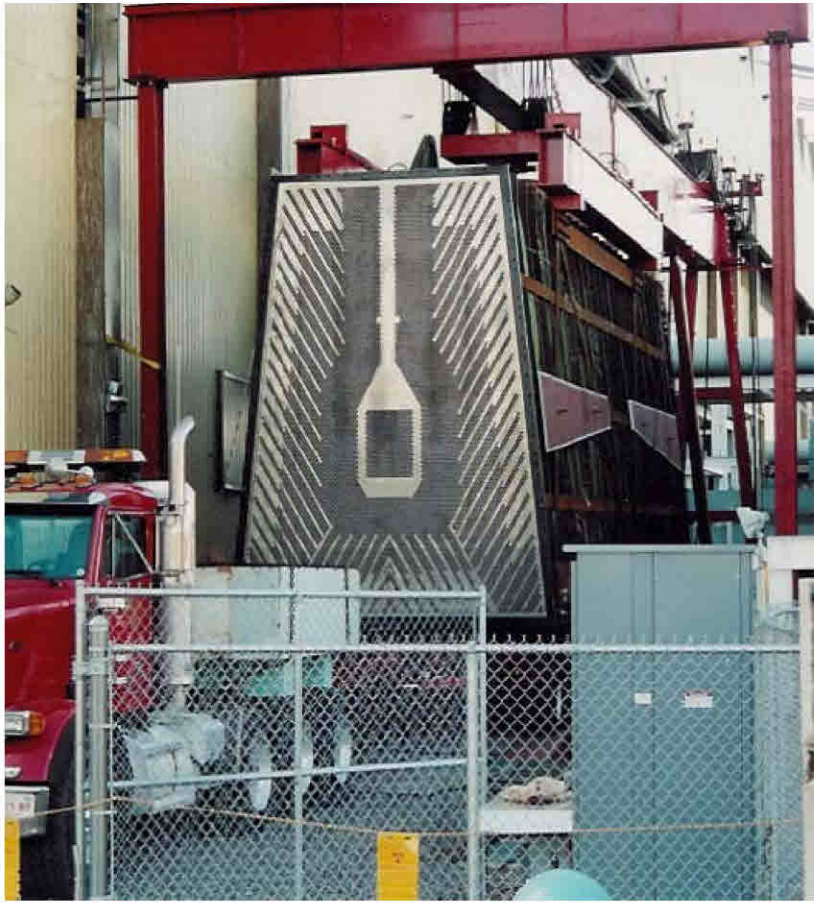
Condenser Module Description (12 ea)

DESCRIPTION	EXISTING	PROPOSED
Surface Area	66,000 ft^2 (792,000 total)	Increased
Tube Material	Admiralty Brass	Titanium
Number of Tubes	4053 (48,636 total)	7166 (86,000 total)
Tube Length	50 feet	50 feet
Tube outside diameter	1-1/4 inches	7/8 inches
Design cleanliness factor	85% (actual 53%)	85%
Width	10 feet	10 feet
Height	12 feet	12 feet
Weight	220,000 pounds	180,000 pounds

One Main Condenser Module



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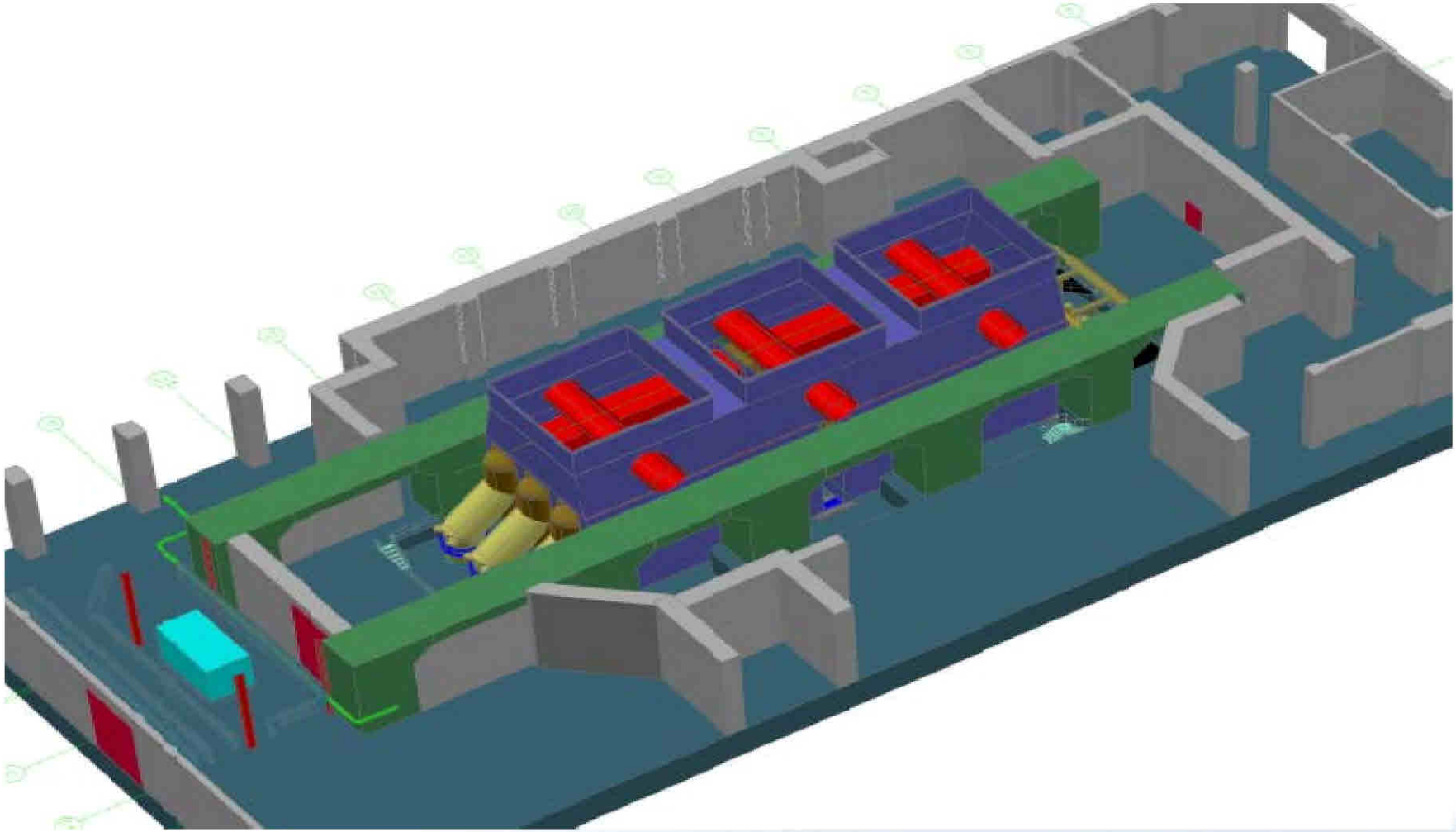
Main Condenser Project: 3D overview



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Discussion

- Best and Final Offers received on 10-09-08
- Reviewed by Source Evaluation Panel using weighted criteria
- TEI ranked to be the most advantageous both technically and the lowest cost
- Recommendation reviewed and approved by Contract Review Board on 10-15-08

Discussion (cont)

- Award of this contract will assist the Project team in:
  - Eliminating current design unknowns
  - Clarifying installation scope of work tasks needed

Discussion (cont)-module being removed

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Discussion (cont)-condenser interior shell

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Discussion (cont)

- Bids received were
  - TEI-$36.1M
  - Yuba-$36.9M
  - Toshiba-43.6M
- Estimates made on:
  - Performance Bond
  - Shipping

Recommendation

- Award Main Condenser Module Design, Fabrication and delivery RFP 651803 to TEI for $37,000,000.

Columbia Generating Station Condenser Project Update

Dave Swank
Manager of Major Projects

Brent Ridge
Asset Manager and Controller

October 22, 2008

Meeting Objectives

- Provide Condenser project status update
- Present revised business case
- Demonstrate Long Range Plan (LRP) stability commitment

Background Summary

- The Condenser needs to be replaced due to:
  - Tube wear and resulting degradation
  - Decreased reliability resulting in lost production
  - Copper impact on fuel
  - Dose reduction

- Multiple options investigated:
  - Copper re-tube using existing tube sheets
  - Titanium re-tube using new tube sheets
  - Stainless Steel (Seacure) modular replacement
  - Titanium modular replacement (best option)

Background Summary

- Original Business Case:
  - Outage Duration 88 Days
  - Estimated most likely cost $106.8M
  - NPV of $18.6M
- Current Approved LRP Condenser Budget: $95M

Project Update

Revised Business Case:

- Outage Duration 65 Days
- Estimated most likely cost $136M
- NPV of $24.3M
- Business Case conclusions remain valid

- Defer decision on a Design and Installation contractor – evaluate options

- Vendor Module selected for Board approval

Cost Saving Options

- Continue to find ways to reduce/define scope of work
- Issue module contract RFP 651803 so install/remove requirements can be finalized and minimized
- Reduce disposal cost by recycling copper tubes

Cost Saving Options

- Utilize Columbia preferred Architect Engineer for remainder of the engineering work
- Use Columbia Site Support contractor for R-19 installation work and potentially for R-20 work.
- Evaluate use of module vendor for installation

Impact of Varying Outage Durations

Expected outage duration is a significant factor that impacts the expected NPV under both project cost scenarios. The table below provides a range of how expected NPV would change from what was previously calculated under different outage durations for the two project cost cases.

Expected Outage Duration	Outage Duration Present Value	$136 Million Project Case NPV	$156 Million Project Case NPV
86 Days	$2,277	$415	($14,408)
85 Days	$3,416	$1,554	($13,269)
80 Days	$9,109	$7,247	($7,576)
75 Days	$14,803	$12,941	($1,882)
73 Days	$17,080	$15,218	$395
70 Days	$20,496	$18,634	$3,811
65 Days	$26,189	$24,327	$9,504
60 Days	$31,883	$30,021	$15,198
55 Days	$37,576	$35,714	$20,891

For $136Million Project Cost Case, outage duration of 86 days or less will result in a positive NPV

For $156Million Project Cost Case, outage duration of 73 days or less will result in a positive NPV

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Business Case Conclusions

- Technical, economic, and regional impact factors drive the need to replace the Main Condenser by 2015.
- The Main Condenser has a direct bearing upon the operability of CGS.
  - Reliable operation after 2015 is uncertain.
- Pursuing a Main Condenser strategy in 2011 is financially more advantageous than doing so in 2015.

Maintaining LRP Stability

- Reconsideration of Projects
- Use of Capital Risk Reserve
- Scope Development and Control

Options

- Do nothing
- Postpone project until R-21
- Increase total CGS LRP
- Implement the project during R-20 and live within the current LRP total cost constraints

Recommendations

- Stay the course to complete the condenser replacement in R-20
  - Resolve the technical issues
  - Delaying the condenser by one outage will reduce benefits by $15M to $20M
  - R-21 installation will conflict with Grand Coulee upgrades
  - No reason to believe that costs will be lower in 2013
- Adjust the total Condenser project cost to $106.8M – original estimate
- Maintain the Columbia LRP total budgets for FY10/11/12
  - Identify possible LRP items for adjustment
  - EAC to make necessary LRP adjustments as part of the FY10 budget process

Questions?

Condenser replacement project-BPA/EN meeting March 14, 2008

Objective: To gain an understanding of the what, how, when, where, etc. of the replacement itself.

✓ 1. **Schedule of implementation (summary & detailed)**

2. **What work will be done in each outage?**

3. **What is the overall strategy?**

4. **How will modules be moved out/back in?** Do as much pre-outage work as possible

looked at 2 bundles. 96 days.
78 days single bundle → cable tray primarily. Some bus duct.
leave options open for Bidder as much as possible.

5. **What is the contracting strategy**
   - **turnkey**
   - **multiple contractors** R-19 design → SL doing a portion & EN doing a portion
   - **incentives/penalties**

yes!

R-19 implementation

R-20 "

on-line design + dwg.

Slope + RFP

R-20 design.

- went + talked to US company.
- 2 plants are competing.
- price will be too stable for 1½ yrs.
Not a shortage of supply.
- its energy dept.
U Americalite. Valcomet.

6. **Procurement strategy for material and modules**

7. **Module delivery** - Now 08
Japan
India
US. (3 different)
Korea
Tube delivery No 2009
Frame 2010 delivery to site.

8. **What challenges are you facing?**

Project Issues

- Module Removal – Pull or Dismantle
- Rail System Configuration
- East Water Box – Remove or Rework In Condenser Bay
- Ingress / Egress- Facility Addition To PAAP
- East Condenser Access/Pressure Relief Valve Facility Move
- Main Condenser Facility – TG Building RCA Extension
- Steam Jet Air Ejectors (SJAE) piping reroute
- Sand Blast / Coating Facility for water box coating
- Project decisions impacted by not having a Turnkey Contractor on site

9. **Contingency planning**

10. **Disposal of old modules**

11. **Design changes; who?** EC # 6693

12. **What work schedule; 24-7?**

MAIN CONDENSER REPLACEMENT PROJECT STATUS REPORT

March 13, 2008

MILESTONES/SIGNIFICANT ACCOMPLISHMENTS

Phase 1 – Scoping (Conceptual Study & Project Plan)

- Updated animation video to include security fence and travel path for single high modules
- Completed FY08 & FY09 schedule in support of the PHC presentation
- Presented Main Condenser Project update on FY-08/09 budget to PHC
- Westinghouse (WEC) issued rev. 1 of the Conceptual Study
- Developed and published a responsibility matrix
- Draft of the Project Plan completed

Phase 2-Procurement & R-19 Planning

- Received proposal from WEC on R-19 Instrumentation Design Work
- Completed a Limited Notice to Proceed for the WEC and S&L engineering scope
    - S&L engineers (9) on-site working R-19 PDC 6693, PDC 6684 and AR 6086-07

- WEC engineer on-site working R-19 PDC 6692
- Action Memo 1050 Design Engineering Support Services for Sargent & Lundy signed off

- ENW/WEC/S&L completed a walkdown of WNP-1 main condenser
- John Lovejoy on-site as Condenser HIT/Main Condenser Project scheduler support & Condenser HIT (Interim)
- ENW/WEC/S&L completed Quanta Cad training

Phase 3 - R-19 Implementation
Phase 4 - On-line Work and R-20 Planning
Phase 5 - R-20 Implementation
Phase 6 - Project Closure

ISSUES AND CONCERNS

- Identification of potential "Turnkey" Installation Contractors
- Impact of not having the "Turnkey" Installation Contract awarded affects the "Rigging Plan", R-19 Travel path Design Package development, and Outage Milestones.
- Obtaining permanent Cost/Scheduler replacement for Pat Ray

NEAR TERM ITEMS

Phase 1 – Scoping (Conceptual Study & Project Plan)

- Continue to revise FY09/FY10/FY11 Project Schedule
- Retubeco to meet with EN to review tube pulling experiences at other BWRs (supports plans to demolish or pull old modules prior to new module installation)
- Award contracts for R-19 Engineering work
- Presentation to Executive Board to approve Long Range Plan, provide Huron Business Case results and present Action Memorandum 1050 for contract award approval of Sargent & Lundy R-19 Design Work
- EAC Presentation on FY08 and FY09 funding to obtain final approval of proposed revisions

Phase 2-Procurement & R-19 Work

- Obtain Electrical Work Order Planner for R-19 work and pre-outage preparation

Budget Performance

- FY08 Approved Budget-$1.8M – $1.4M Spent and Committed; Expected increase following submittal of FY08 PCF to approximately 4.6M scheduled for 03-13-08. (Current is $1.777M)
- FY09 PCF to approximately 25.0M scheduled for 03-13-08 (Current funding is $36.5M)

Progress Report on ACPRT Review
CGS Condenser Replacement

The Agency Capital Project Review Team (ACPRT) is reviewing the business value of Energy Northwest (ENW)'s condenser replacement project for BPA. The review is focused on the financial implications of four alternatives that were considered in a Huron Consulting Group study commissioned last winter by ENW:

1. Titanium modular replacement installed in 2011;
2. Titanium modular replacement in 2015;
3. Titanium retube with new tubesheets in 2011; and
4. Titanium retube with new tubesheets in 2015.

The Huron Study concluded that the Titanium modular replacement – 2011 alternative was preferable because it offered greater technical and operational benefits than the titanium retube alternative and because it was financially advantageous to proceed sooner rather than later. ENW included the modular replacement – 2011 alternative in its FY 2009 budget, which the ENW Board approved and BPA non-disapproved in late spring 2008. This alternative is also reflected in the spending levels that BPA proposed in the Integrated Program Review.

The Huron Study process was largely closed to BPA and other stakeholder review until it was completed in February 2008. The Study's analytical approach, assumptions, and results were documented, however, and the Study serves as the primary source of financial data for the ACPRT's review. Huron evaluated the financial costs and benefits of the alternatives using the same life cycle costing/net present value method that Bonneville now uses to evaluate other capital projects. At the Administrator's direction, the review is being conducted with currently available materials; no request has been made for supplemental information from ENW or Huron, and no business case was requested or submitted. PGC is a full partner in the review.

We anticipate completing the review by the first week in August. Power Services will be briefed and comments considered before findings are advanced to the CAB. The ACPRT's report will cover the (1) financial and risk implications of the project alternatives and (2) a high-level assessment of ENW's capital decision practices with regards to BPA's asset strategy and standards for capital project valuation.

The ACPRT has replicated the financial analytics performed by Huron, and issues have been found that affect the calculation of net present values for the four alternatives. For example:

- The discount rate that Huron used to determine the net present value of the alternatives was 6.5 percent (reflecting ENW's weighted average cost of capital), rather than the 13 percent risk-adjusted discount rate that BPA has established for Federal hydro and other capital projects in Power Services.
- Incremental cash flows for each alternative were not developed by comparison to a reference, or "no action" case. All other things equal, the net effect of this is that long-term benefits were overstated
- Replacement power costs (due to lost generation) and savings were not fully accounted for, nor was replacement power cost uncertainty.

We are re-running the analytics now, and offer no findings or conclusions at this point.

DRAFT

8/11/08

has AJR Comments

ACPRT Review

CGS Condenser Replacement Project

Scope

Methodology

Results

Scope and purpose

Scope of review

- **The Huron Study assessed the financial implications of two, operationally viable project alternatives under two installation timeframes**
  1. Titanium modular replacement installed in 2011
  2. Titanium modular replacement installed in 2015
  3. Titanium retube with new tubesheets in 2011
  4. Titanium retube with new tubesheets in 2015

- **The Huron Study concluded that alternative 1 – Titanium modular replacement installed in 2011 – was preferable**
  - Financially most advantageous

Huron spreadsheet

	Net present values (Expected values - $000) 2011	2015
Modular titanium replacement	**5,535**	**(668)**
Titanium retube with new tubesheets	**(103,803)**	**(90,873)**

* Huron's presentation, "Main Condenser Business Case", shows $18,652 for modular titnium replacment and $(90,714) for titanium retube. These amounts are not substantiated by the cdocumentation available to the ACPRTS, however.

  - Modular replacement otherwise preferable to re-tubing alternative (less contamination risk, less risk of damage to tubes during installation (extends length of outage), improved thermal performance)

Scope of review

was non disapproved

FY09 too

- **ENW approved the project largely on the strength of Huron's recommendation**
  - BPA non-disapproved FY 2009 budget (FY 2009 funding)
  - Procurement contract non-disapproval will be due in October/November
- **The ACPRT's "due diligence" review is focused on the methodology and assumptions Huron used to assess the financial implications of the four alternatives**
- **At the Administrator's direction, the ACPRT's review relies on existing, currently available materials and PGC expertise only**
- **No request has been made for supplemental information from ENW or Huron, and no standardized business case has been submitted**

Scope of review *(3)*

- **Unlike other project reviews, the ACPRT is making no recommendation on a project alternative**
  - A full business case and access to Huron and to ENW SMEs would be needed first
  - Project execution risks are very large -- and access to a project plan to test risk management planning and controls would also be needed

- **Rather, we provide our critique of the Huron Study and our assessment of the alternatives' financial implications**

Methodology

Huron Study's methodology

- **The Huron Study employed net present value as the financial metric that determines the alternative that is financially most advantageous**
  - Cash flows over the investment's expected life span were developed for each alternative
  - The cash flows for the alternatives were then discounted and compared
- **The Study then recommended the alternative shown to have the most favorable NPV**
- **In concept, Huron's approach – determine net present values based on life cycle cost and benefit cash flows – comports with BPA's approach to capital project valuation**

Huron Study's methodology (2)

- **The Huron Study process was largely closed to BPA and other stakeholder review and comment until it was completed in February 2008**

- **That said, the Study's analytical approach, assumptions, and results are documented**
  - BPA staff gained access to the spreadsheets Huron used to determine cashflows and NPVs
  - For many data inputs, we know what was assumed but often not why

ACPRT's approach

- **ACPRT's review is limited to the titanium modular replacement and titanium retube alternatives covered by the Huron Study**
  - We accept ENW's judgment that other alternatives – e.g., copper retube using existing tubesheets and stainless steel modular replacement -- are unacceptable operationally/technically
- **ACPRT has created an NPV-based model that starts with Huron's spreadsheets**
  - The model allows us to make corrections, updates and enhancements to Huron's analysis

The ACPRT employs the same financial metric, the same life-cycle cash flow approach, and essentially the same source data as Huron

ACPRT's approach (2)

- **No changes have been made to Huron's project cost data**
  - In other words, no change to procurement, installation, testing and decon/disposal data for the modular replacement and retube alternatives
  - Huron Study identifies ENW and Industry SME sources
  - No access to these sources, therefore no ability to test project cost and cost uncertainty data
- **Updates and enhancements have been made to lost revenue/replacement power cost data and modeling**
- **Several methodological and other analytical fixes have also been made**

ACPRT changes to Huron's modeling

Significant issue, not the only only one

- **Incremental cash flows in the Huron Study were not developed by comparison to a base case**
  - For purposes of determining net present values, cash flows must be incremental cashflows
  - For this project, incremental cash flows should be determined by reference to a "run to failure" base case
  - The Huron study did not apply a base case consistently – the modeling effectively assumed that the current condenser never fails, meaning that . . .
    - There are benefits shown for an undue length of time
    - There are no costs to replace it when it does eventually fail
  - All other things equal, the net effect of this error is that the long-term benefits of the alternatives are overstated
  - ACPRT's base case assumes that the current condenser will be replaced or re-tubed in 2018 (estimated end of condenser's useful life – PGC)
    - Sensitivity is also run for replacement/retubing in 2020

2018

I'll run the model with just this change isolated

ACPRT changes to Huron's modeling (2)

- **Lost revenue/replacement power cost estimates did not fully capture market price and outage duration uncertainties**
  - ACPRT is now using an updated, probabilistic forecast of market prices
  - A "worst case" outage duration case has now been added (incremental 30, 40, and 62 days)
- **A couple of cost factors were improperly treated**
  - For example, eddy current testing costs were calculated on a gross not incremental basis, and they were improperly treated in the cashflows
- **Horizon of cashflows extends beyond estimated useful service life**
  - Horizon of cash flows reduced to 20 years, with an estimate of the condenser's residual value inserted at year 20
    - Not a flaw in Huron's Study, but this change comports with BPA's treatment of other capital projects
    - ACPRT determined the residual value as net book value in year 20 — undepreciated life

assumed 40 years useful life

$1M impact.

about 9% is where the crossover point for 2011 to 2015

- **Discount rate was not risk-adjusted and inconsistent with BPA's standard**
  - Huron Study: 6.5 percent (reflecting ENW's weighted average cost of capital)
  - ACPRT review: 13.0 percent (risk-adjusted discount rate for Federal hydro and all other capital projects in Power Services)

pretty substantial change

makes a later installation a better deal

– Same rate for Fed. Hydro projects

risk adjusted

weighted average cost of capital

David B

mike: We're prepared to dig in on this one. It's what been decided by BPA.

ACPRT modeling results

Huron using 3% escalation for all costs. ACPRT tried to split up components and have ability to use different escalation factors — but in the end they used 3½%

H's not validated for Aurora yet. (latest H's) from last Friday.

Expected value costs

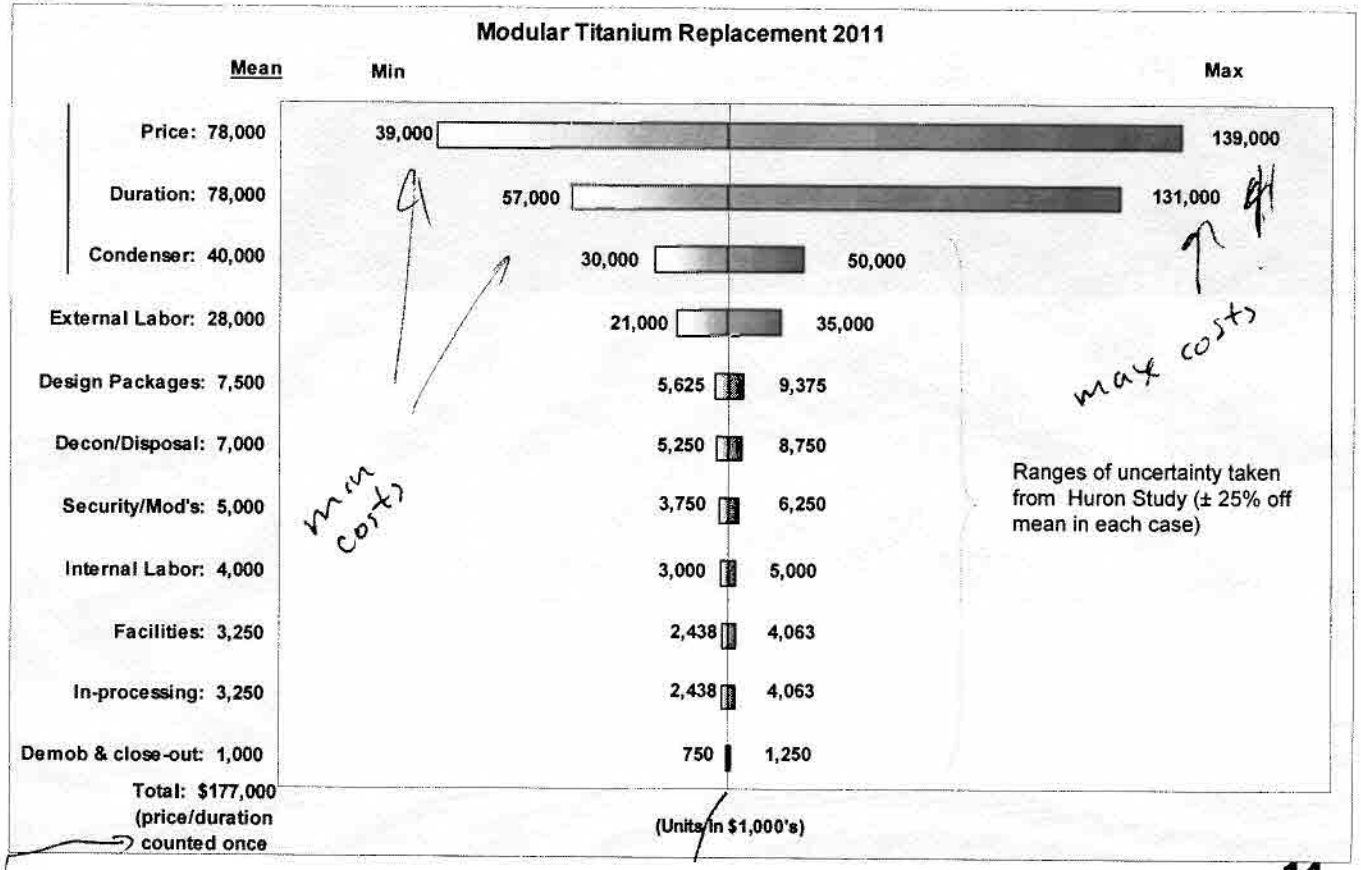
(Nominal totals thousands of dollars)

	Installation Year 2011			2015			2018	
	Huron Study	ACPRT review		Huron Study	ACPRT review		Huron Study	ACPRT review
Titanium modular replacement								
Project Costs	106,370	98,958	-7412	96,468	115,437	18969	n/a	127,987
Lost revenue/replacement power costs during installation	71,756	78,813	7,057	80,841	80,841	0	n/a	91,753
	178,126	177,771	(355)	177,309	196,278	18,969		219,740
Net present value	5,535	(31,014)		(90,873)	(8,946)			
Retube - titanium sheets								
Project Costs	87,095	86,915	(180)	98,781	101,703	2,922	n/a	118,406
Lost revenue/replacement power costs during installation	71,073	78,813	7,740	80,071	86,143	6,072	n/a	91,753
	158,168	165,728	7,560	178,852	187,846	8,994		210,159
Net present value	(103,803)	(38,862)		(90,873)	(11,995)		n/a	n/a

Market price and outage duration are the greatest risks

Titanium and other procurement cost risks are also big

Tornado charts shows range of uncertainty



only one is taken & counted, of the price, or duration

min line or value

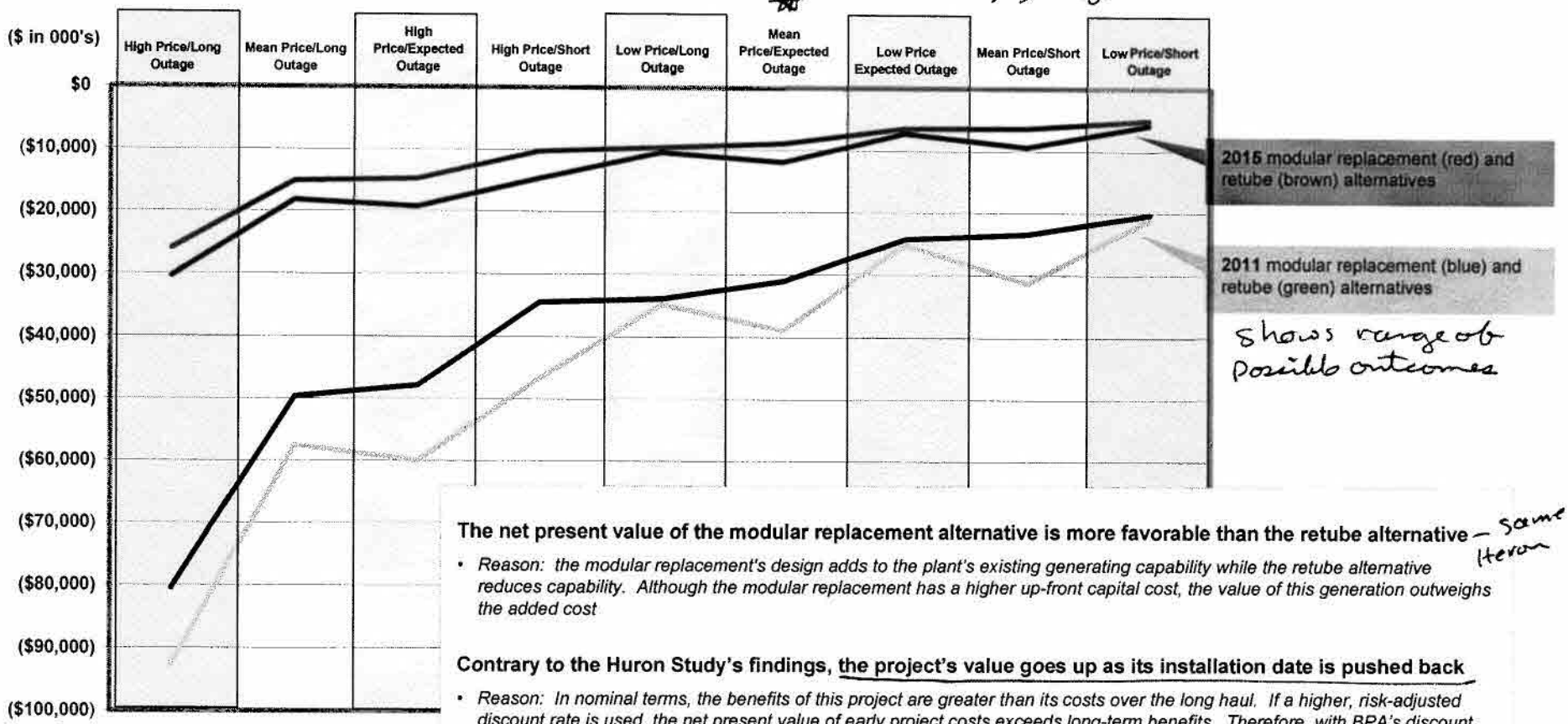
mean line

max line

doesn't capture uncertainty around project costs only used expected value

3.5% Project Cost Escalation

NPV as a Function of Market Price and Outage Duration Variability



shows range of possible outcomes

The net present value of the modular replacement alternative is more favorable than the retube alternative – same as Huron

- *Reason: the modular replacement's design adds to the plant's existing generating capability while the retube alternative reduces capability. Although the modular replacement has a higher up-front capital cost, the value of this generation outweighs the added cost*

Contrary to the Huron Study's findings, the project's value goes up as its installation date is pushed back

- *Reason: In nominal terms, the benefits of this project are greater than its costs over the long haul. If a higher, risk-adjusted discount rate is used, the net present value of early project costs exceeds long-term benefits. Therefore, with BPA's discount rate (13.0% Vs Huron Study's 6.5%), a later installation date is more economic*

NPV variability is driven largely by the length of outage and prevailing market prices

- *Lost revenue/replacement power costs can more than double the NPV cost of the current 2011 installation plan*
- *Titanium price risk and other project risks are not reflected*

2018 replacement would be the best if that case were run.

extension would begin in July.

Managing cost risks

Start April 2
+ 35 days regular outage
+ incremental outage days of 40.

guestimate.

Outage duration risks

- **Expected increment duration of planned outage is 40 days**
  - Range of uncertainty is 31 to 61 days, with lost revenue/net replacement costs ranging from $ to $
- **What could go wrong?**
  - (to be added)

installation problem
operational risk
failure to execute on the plan.
manufacturing error (unknown, unexpected)

- **What the objectives be to manage these risks?**
  - (to be added)

one planned.

- **What steps ~~should be taken~~?**
  - (to be added)

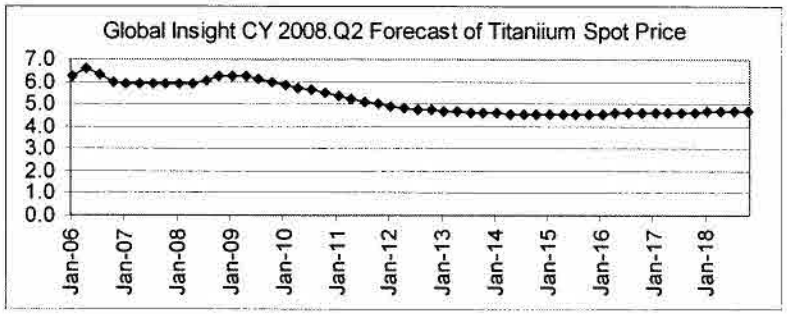
Consultants -
benchmarking

Managing cost risks (2)

Procurement cost risks

- **Procurement costs are estimated in the Huron Study at $40 million, with cost uncertainty ranging from $30 million to $50 million**
  - Vendor bids are due in October

- **Titanium prices are the key uncertainty -- prices have been volatile and escalating in recent years. Forecast is that titanium prices will decline – but uncertainty remains**
  - Unclear what the Huron Study assumed for titanium prices



CGS Condenser Replacement Project

ACPRT Review

Presentation to the CAB *September 2008*

Scope

Methodology

Results

Scope and purpose

Scope of review

- **The Huron Study assessed the financial implications of two, operationally viable project alternatives under two installation timeframes**
  1. Titanium modular replacement installed in 2011
  2. Titanium modular replacement installed in 2015
  3. Titanium retube with new tubesheets in 2011
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- **The Huron Study concluded that alternative 1 – Titanium modular replacement installed in 2011 – was preferable**
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	Net present values (Expected values - $000) 2011	2015
Modular titanium replacement	**5,535**	**(668)**
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  - Modular replacement otherwise preferable to re-tubing alternative
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* Note: The Huron Study cited these as benefits of the modular replacement alternative that are above and beyond the NPV-financial benefits. In fact, these factors were captured in the NPV-financial analysis.

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- **ENW justified and approved the project based on the Huron Study**
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- **That said, the Study's analytical approach, assumptions, and results are documented**
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  - We accept ENW's judgment that other alternatives – e.g., copper retube using existing tubesheets and stainless steel modular replacement -- are unacceptable from an operational/technical standpoint
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  - The model allows us to make corrections, updates and enhancements to Huron's analysis

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- **No changes were made to Huron's project cost data**
  - In other words, no changes were made to procurement, installation, testing and decontamination/disposal data for the modular replacement and retube alternatives
  - The Huron Study identified ENW and Industry SMEs as sources for these data
  - We had no access to these sources: therefore no ability to test the basis and uncertainties associated with project cost data
- **Updates and enhancements were made to market price and outage assumptions, data, and modeling**
  - to better ascertain the impact of alternatives on lost revenues, increased revenues, and replacement power costs
- **Several methodological and other analytical fixes were also been made to the financial analysis**

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  - The issue isn't whether the current condenser will need to be replaced or re-tubed – but rather *when* the installation will be most cost-beneficial
  - Therefore, the incremental cash flows for the 2011 and 2015 alternatives should be determined by reference to a "run to failure" base case
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  - A "worst case" outage duration case has now been added (incremental 31, 40, and 62 days)
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  - Horizon of cash flows were limited to 20 years, with an estimate of the condenser's residual value inserted at year 20
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  - Huron Study: 6.5 percent (reflecting ENW's weighted average cost of capital)
  - ACPRT review: 13.0 percent (risk-adjusted discount rate for Federal hydro and all other capital projects in Power Services)

ACPRT modeling results

	Expected values					
	2011 Installation			2015 installation		
	Huron Study	ACPRT Review	Difference	Huron Study	ACPRT Review	Difference
Titanium modular replacement						
Project costs	106,370	106,938	568	120,933	120,915	(18)
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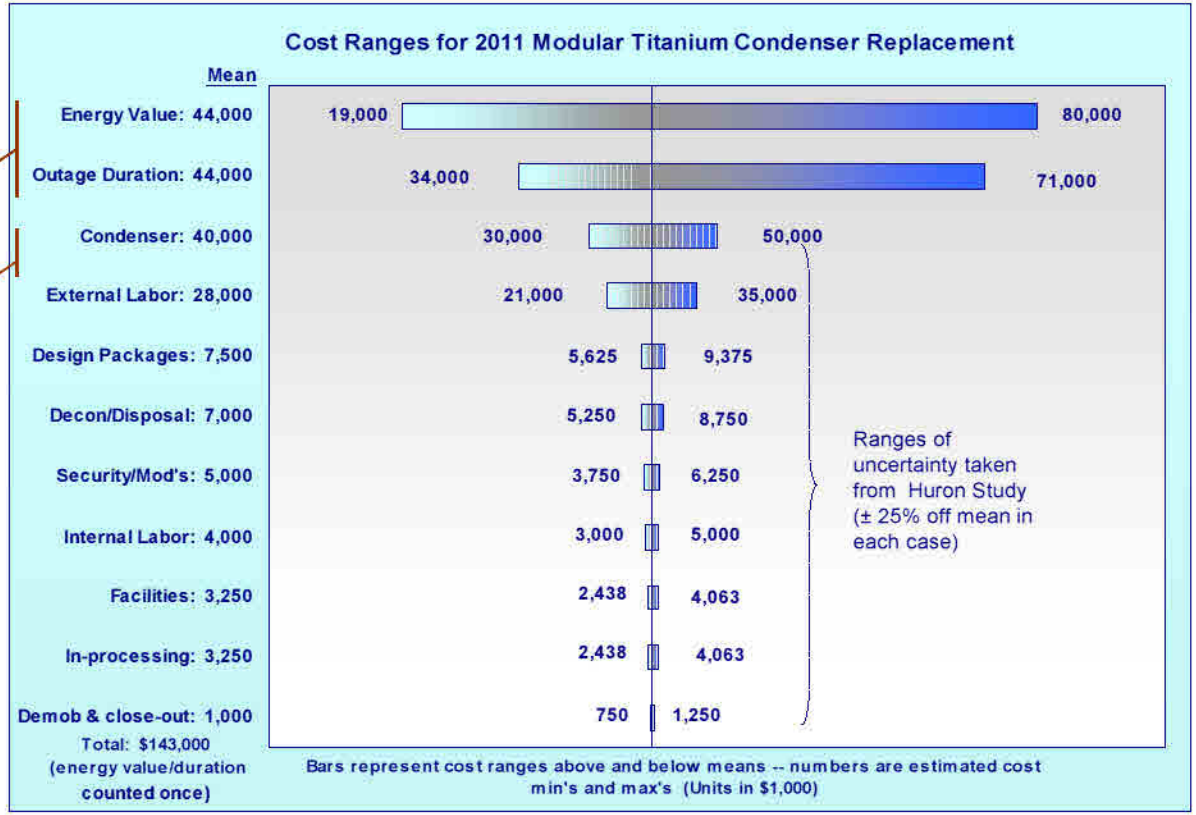
On an expected value basis, 2015 installation of the modular replacement alternative is the most favorable alternative

Cost uncertainties are very large

Market price and outage duration uncertainties are the biggest drivers

Procurement cost risks are also big, largely because of titanium price uncertainty. Uncertainty will be reduced in EN's vendor bid process now underway



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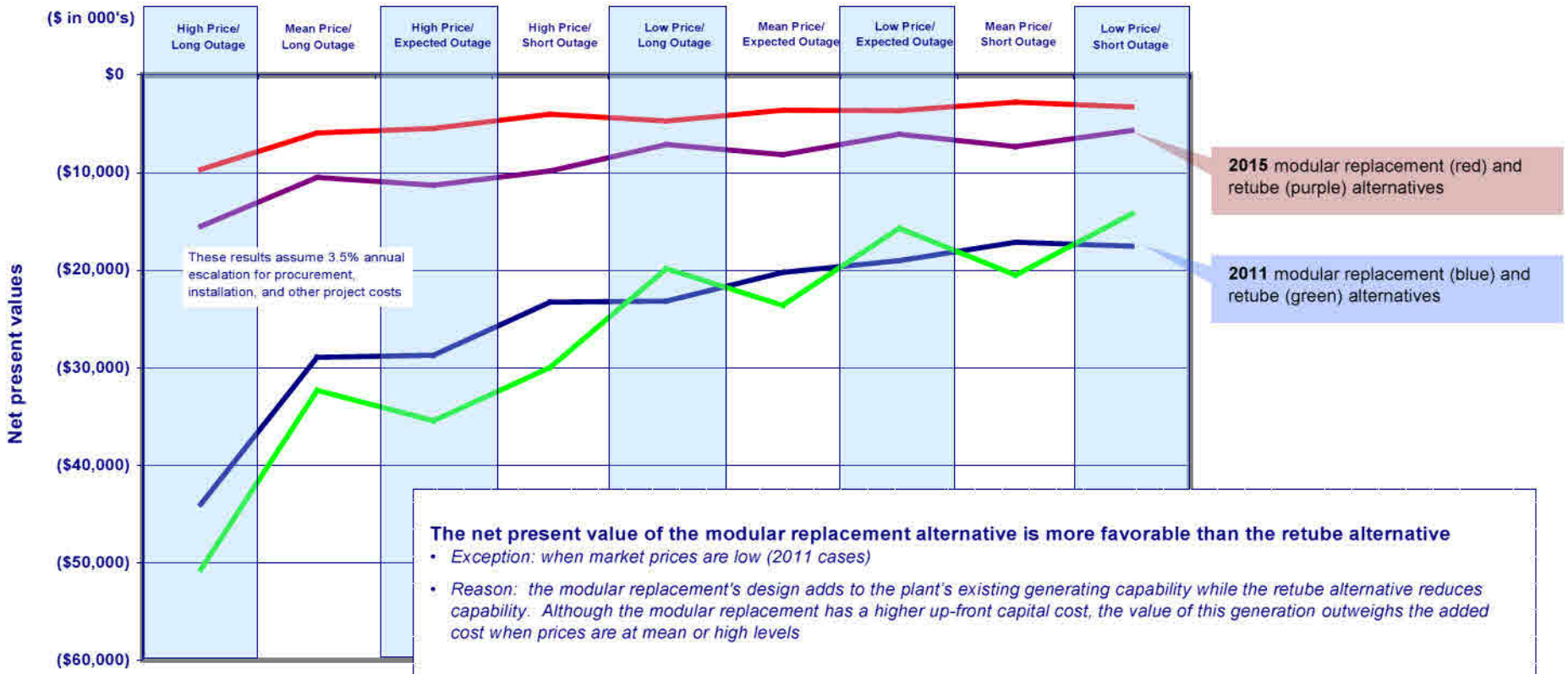

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Managing cost risks

What could go wrong, and what steps should be taken?

Updated 9/30/2008

	Risks	Controls and Treatments
Timing	Project coincides with big unit outages at GCL results in higher power purchase expenses	• Coordinate with Federal Hydro; get condenser project done before GCL big unit outages (805 mw) begin in late August, 2012, and go on continuously for 10 years. • If condenser project done after 2012, shift the GCL schedule to create an opening for the condenser project
Approval Process	Insufficient information or time for BPA to approve or disapprove "term sheet" results in uninformed decision	• Need to inform PGC and EN that we need information well in advance of the 7 day " non-disapproval" process
	Project team / management doesn't adequately oversee the project resulting in delays and cost overruns	• PGC monitors as best they can and provides early warning of management problems
Cost	Value of lost energy during outage can be greater than estimates when project approved	• Review energy forecasts and prices and outage schedule before outage begins and develop energy strategy
	Titanium price escalates and EN/BPA ends up paying more	• Contractor takes price risk and incorporates it into project costs • EN takes risk and develops hedging strategy • PGC researches industry standard practice, BPA determines whether it has any preferences, and informs EN
Design	Condenser designed incorrectly resulting in delays and cost overruns	• Manufacturers visit CGS to get familiar with the plant and design requirements • EN quality assurance inspectors on site at manufacturer's plant
	Uncertainty about equipment design may cause large labor cost contingency to be built into installation bids	• *Resolve equipment design uncertainties* • *Send out "best and final offer" (BAFO) request with refined work scope* • *Re-do cost/benefit studies* • *EN does work themselves that they would otherwise contract out*

Italics = new actions not underway

Managing cost risks

What could go wrong, and what steps should be taken?

	Risks	Controls and Treatments
Manufacturing	Condenser manufactured incorrectly resulting in delays and cost overruns	• EN quality assurance inspectors on site at manufacturer's plant •
Installation	Overall	• EN develops outage plan and risk management plan • PGC has access to and reviews the outage plan, including the risk management plan • PGC performs on-going high level review of project progress • PGC attends Condenser Project Steering Committee meetings • EN and PGC visiting Laguna Verde as they install new condenser
	Prep work is insufficient (reinforcing structures needed when condenser is removed) resulting in delays and cost overruns	• Contingency plans • EN hiring industry expert consultants who have condenser replacement experience at other plants • EN ready to maintain existing condenser if install doesn't go right
	Labor shortages, possibly up to 400 in welding and other specialized fields, result in needing to extend the planned outage timeline	• Rely on industry practice/culture of sharing employees and contractors during outages • EN plans on barrowing workers from mid-west nuclear facilities • Summer outage at CGS won't coincide with the outage season in mid-west
	Something fundamentally flawed with the installation plan or CGS unable to receive a correctly designed condenser	• Outage plan reviewed by other utilities, manufacturers, BPA, others? • CGS visiting other plants to gather insights
	Equipment problems (e.g. Gantry crane can't be supported by CGS floor) resulting on delays and cost overruns	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
	Incorrect installation resulting on delays and cost overruns	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
	Schedule slippage	• Installer contract incentives
	Damage to condenser during installation	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
Restart	Plant doesn't restart as planned resulting in lost energy sales revenues or power purchase expenses	• Shake-out period incorporated into the scheduled outage duration • *Bulk Hub hedges forecasted extended outage period deficits with purchases, options, financials, etc., hedging any forecasted outage period surpluses by selling more cautiously*

Italics = new actions not underway

9/20/08
Version.

CGS Condenser Replacement Project

ACPRT Review

Presentation to the CAB *September 2008*

Version sent out
9/20/08 e-mail
from Mary Hawken.

Scope
Methodology
Results

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→ mandated for use for all Power Services Projects

ACPRT modeling results

reflects lower price forecast

Modeling results

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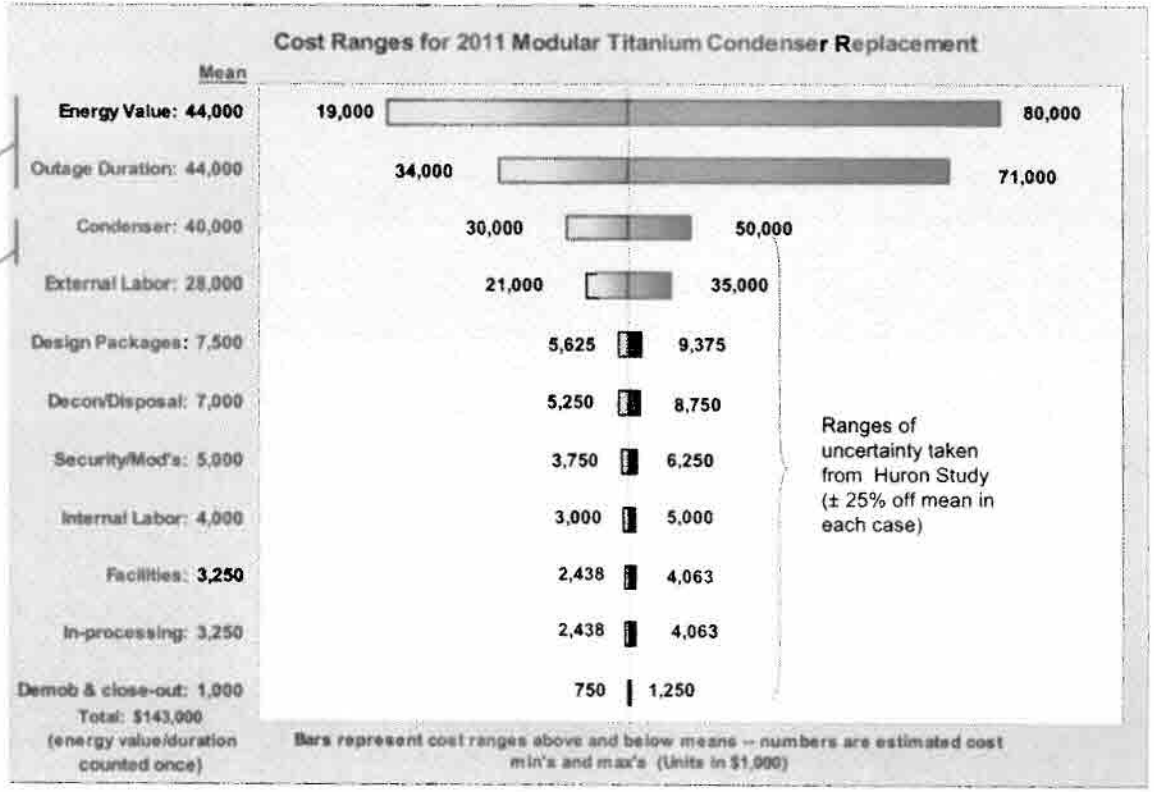
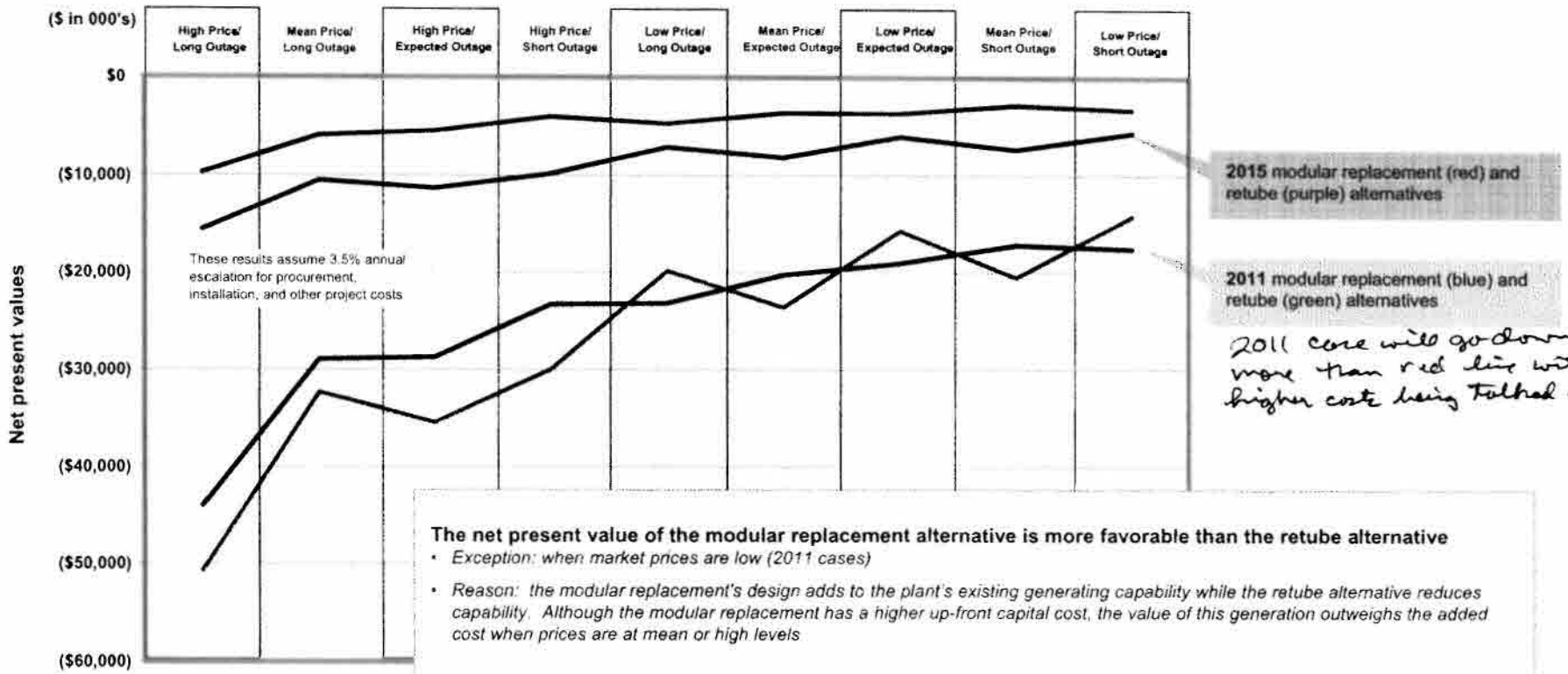


It's not just the module, its also the installation design + work

9/23/2008

06 → 120m → 136m

NPV as a Function of Market Price and Outage Duration Variability



2011 case will go down more than red line with higher costs being talked about.

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What could go wrong, and what steps should be taken?

Ed Blickhaus
Much of this is already occurring
– italics are new

	Risks	Controls and Treatments
Timing	Project coincides with big unit outages at GCL results in higher power purchase expenses	• Coordinate with Federal Hydro; get condenser project done before GCL big unit outages (805 mw) begin in late August, 2012, and go on continuously for 10 years. • *If condenser project scheduled for after 2012, shift the GCL maintenance schedule to create an opening for the condenser project*
Approval Process	Insufficient information or time for BPA to approve or disapprove "term sheet" results in uninformed decision	• *Need to inform PGC and EN that we need information well in advance of the 7 day " non-disapproval" process*
	Project team / management doesn't adequately oversee the project resulting in delays and cost overruns	• PGC monitors as best they can and provides early warning of management problems
Cost	Value of lost energy during outage can be greater than estimates when project approved	• *Review energy forecasts, prices, and outage schedule before outage begins and develop energy marketing strategy*
	Titanium price escalates and EN/BPA ends up paying more	• Contractor takes price risk and incorporates it into project costs • EN takes risk and develops hedging strategy • *PGC researches industry standard practice, BPA determines whether it has any preferences, and informs EN*
Design	Condenser designed incorrectly resulting in delays and cost overruns	• Manufacturers visit CGS to get familiar with the plant and design requirements • EN quality assurance inspectors on site at manufacturer's plant
Manufacturing	Condenser manufactured incorrectly resulting in delays and cost overruns	• EN quality assurance inspectors on site at manufacturer's plant

– Not a good option for BPA

Italics = new actions not underway

Managing cost risks

What could go wrong, and what steps should be taken?

	Risks	Controls and Treatments
Installation	Overall	• EN develops outage plan and risk management plan • *PGC has access to and reviews the outage plan, including the risk management plan, and shares information with the ACPRT* • PGC performs on-going high level review of project progress • PGC attends Condenser Project Steering Committee meetings • EN visiting Laguna Verde and Limerick as they install new condenser
	Prep work is insufficient (reinforcing structures needed when condenser is removed) resulting in delays and cost overruns	• Contingency plans • EN hiring industry expert consultants who have condenser replacement experience at other plants • EN ready to maintain existing condenser if install doesn't go right
	Labor shortages, possibly up to 400 in welding and other specialized fields, result in needing to extend the planned outage timeline	• Rely on industry practice/culture of sharing employees and contractors during outages • EN plans on barrowing workers from mid-west nuclear facilities • Summer outage at CGS won't coincide with the outage season in mid-west
	Something fundamentally flawed with the installation plan or CGS unable to receive a correctly designed condenser	• Outage plan reviewed by other utilities, manufacturers, BPA, others? • CGS visiting other plants to gather insights
	Equipment problems (e.g. Gantry crane can't be supported by CGS floor) resulting on delays and cost overruns	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
	Incorrect installation resulting in delays and cost overruns	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
	Schedule slippage	• *Installer contract incentives*
	Damage to condenser during installation	• Contingency plans • EN ready to maintain existing condenser if install doesn't go right
Restart	Plant doesn't restart as planned resulting in lost energy sales revenues or power purchase expenses	• Shake-out period incorporated into the scheduled outage duration • *Bulk Hub hedges forecasted extended outage period deficits with purchases, options, financials, etc., while hedging any remaining forecasted outage period surpluses by selling more cautiously*

Italics = new actions not underway

Managing cost risks *(3)*

- **What are the other procurement contract risks?**
  - (to be added)

- **What should the objectives be to manage these risks?**
  - (to be added)

- **What steps should be taken?**
  - (to be added)

Public Power Council

1500 NE Irving, Suite 200
Portland, Oregon 97232
503.232.2427
Fax 503.239.5959

May 5, 2006

Paul Norman
Senior Vice President, Power Business Line
Bonneville Power Administration
c/o Public Affairs Office – DKC - 7
P.O. Box 14428
Portland, OR 97293-4428

Re: PPC's PFR II Comments and CGS Condenser Replacement

As a result of discussion at its May 4 Executive Committee meeting, the Public Power Council would like to clarify our comments on Power Function Review (PFR) II regarding the issue of the condenser replacement at the Columbia Generating Station (CGS). In our April 26th comments, we said: "We do, however, question the timing of the funding for the main condenser replacement, given that the planning and design has not yet been fully developed and other alternatives have not yet been explored. Given that there is $35 million in placeholder capital costs for the condenser replacement in the spending estimates for the FY07-09 period, we are interested in the follow-up report on this investment."

As also noted in our April 26th comments, "BPA's customers recognize that the reliable and safe operation of CGS is essential to BPA's power portfolio." Taken together, these statements should *not* be read to mean that the condenser should not be replaced. Rather, if replacement is deemed necessary after consideration of the alternatives, then the condenser should be replaced. Also as BPA notes in its PFR II draft closeout report, "BPA customers expressed interest in receiving a follow-up report on EN's plan in regard to condenser replacement and EN and BPA intend to provide this follow up." BPA's customers remain interested

in follow-up discussions on this topic, to gain additional understanding of the different ways ENW had researched to address its main condenser problems.

Thank you for the opportunity to make this clarification.

Sincerely,

Marilyn Showalter
Executive Director

Public Power Council

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503.232.2427
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April 26, 2006
Via Electronic Mail

Paul Norman
Senior Vice-President, Power Business Line
Bonneville Power Administration
c/o Public Affairs Office – DKC - 7
P.O. Box 14428
Portland, OR 97293-4428

Re: Comments on BPA's Power Function Review II Draft Closeout Report

Dear Mr. Norman:

As the second phase of the Power Function Review process (PFR II) approaches its end, PPC would like to offer some observations and comments for your review, based on your draft closeout report issued on April 4. PPC has again coordinated the responses of a number of groups that have been following this process. We found the PFR II process to be fair, open, cooperative, and creative, and we were encouraged by the level of commitment of all parties to share and understand information on BPA's cost drivers. We especially want to thank you, Michelle Manary, Nita Burbank, and many others for your efforts in making PFR II a constructive process. Further, building on the PFR II experience, we hope to meet more regularly with representatives from the Corps of Engineers (Corps), Bureau of Reclamation (Bureau), EnergyNorthwest (EN), and the Northwest Power and Conservation Council (Council) to deepen our understanding of their budgets and their relation to BPA's budget.

Our sincere appreciation of the PFR II process, and of many of the cooperative ideas and actions arising out of that process, does not mean we agree with *all* of

the results of the process. In that regard, as you draft your final closeout report, we urge you and BPA's sister-agencies to consider the following:

SUMMARY OF RECOMMENDATIONS

- **Extend amortization for conservation investments to 15 years.**
- **Extend amortization for F&W investments to greater than the minimum of 15 years.**
- **Inform customers of EN capital investment plans well-prior to final decision.**
- **Modestly increase forecasted output of Columbia Generating Station (CGS).**
- **Implement the hydro-benchmarking study and associated savings.**
- **Shift F&W funds from R, M & E to direct-benefit projects.**
- **Do not exceed $40 million in DSI benefits.**
- **Accelerate implementation of EPIP Phase One and reduce Internal Operations costs by an additional $4 million/year.**
- **Adjust conservation target by incorporating utility-funded projects, as appropriate.**
- **Remove Fourmile Hill project from this rate period, model the facilitation budget through NORM, and initiate a new facilitation funding process.**
- **Include customers in the Council's budget-planning process.**
- **Initiate on-going examination of forecasted budgets, with appropriate customer participation.**

COMMENTS AND RECOMMENDATIONS

A. Capital Cost Recovery

1. Extend amortization for conservation investments to 15 years. In general, we encourage BPA to match debt life with the life of the investment because this principle comports with sound business practices and better matches the recovery of costs from those that benefit from an asset. BPA has pointed to the Council's study, which found a median of a 15-year asset life for conservation investments installed after FY06. Accordingly, we recommend that BPA adopt a 15-year amortization period for its capitalized conservation investments, instead of the 5-year period assumed in the draft closeout report. Although this change does not significantly affect rates in the near term, after 2011 rates will be modestly relieved. Further, this change will make the amortization period comport more closely with the 20-year amortization period assumed for conservation before the new policy of debt financing over 5 years went into effect.

2. Extend amortization for F&W investments to greater than the minimum of 15 years. Similarly, we believe BPA should expand the assumed amortization period for Fish and Wildlife investments because using the 15-year period seems to reflect only the minimum life associated with these investments. A longer period should be assumed in order to reflect the average life of all the capitalized Fish and Wildlife investments in BPA's direct program

3. Inform customers of EN capital investment plans well-prior to final decisions. We would like to continue to be informed of discussions with EN about the wisdom of the capital improvements proposed for the FY07-09 period. The region helped the EN Executive Board make an informed decision regarding the proposal to extend the outstanding CGS debt past 2018 based on the costs and benefits of the proposal. We see this model as one to follow for future CGS-related debt and capital decisions.

B. Modestly increase forecasted output of Columbia Generating Station (CGS).

The operating costs of CGS (at 9% of BPA costs) represent a significant percentage of BPA's total costs. The recovery of CGS capital costs is more than 18% of BPA's total costs. While these costs represent a significant cost category, BPA's customers recognize that the reliable and safe operation of CGS is essential to BPA's power portfolio. The customers intend, however, to become more

active in the EN budget process prior to the time these costs show up in BPA's rates.

At the PFR II Manager's Meeting on March 8, 2006, CGS described a need for additional funding of $13.8 Million/year for increased O&M and an increase in capital expenditures of $22.9 Million/year on average over FY07-09. These amounts would be in addition to the CGS expenditures included in BPA's Initial Rate Proposal. In the month following this meeting, CGS was able to determine that it could internally fund these additional expenditures through additional revenues from CGS uranium remarketing efforts. The result is no net increase in CGS expenditures over BPA's Initial Rate Proposal, and the effect on BPA's proposed rates is now forecasted to be a net decrease of $2 Million/year due to forecasted increased revenues from uranium remarketing.

We commend CGS for finding innovative ways to offset the costs of these additional O&M and capital requirements. We also appreciate EN staff's participation in the PFR process and expect that this will lead to better coordination of EN's funding needs and BPA's rates in the future.

We do, however, question the timing of the funding for the main condenser replacement, given that the planning and design has not yet been fully developed and other alternatives have not yet been explored. Given that there is $35 million in placeholder capital costs for the condenser replacement in the spending estimates for the FY07-09 period, we are interested in the follow-up report on this investment.

During the CGS presentation on March 8, Scott Oxenford, VP Technical Services, Energy Northwest, acknowledged that the additional O&M and capital expenditures will improve CGS performance and are expected to increase capacity factor and plant availability of CGS. According to BPA, its "forecast of 1,000 aMW for CGS in non-maintenance months provides an accurate, though slightly conservative estimate of the annual generation potential for CGS." This forecast was prepared in July 2005 and did not incorporate the effect of these additional O&M and capital expenditures. As a result, in its Final Proposal, BPA should modestly increase the BPA forecast for CGS generation output for FY07-09 to a slightly less conservative amount of 1,030 aMW in the non-maintenance months.

C. Implement the hydro-benchmarking study and associated savings.

We continue to feel that better communication is needed among BPA, BPA's customers, and the Corps and Bureau. For example, in PFR I we discovered $1.5 to $1.6 billion of Columbia River Fish Mitigation Studies that were coming into plant-in-service that had not been anticipated by the customers. During the course

of PFR II we found that the Corps was considering a $30 million Flood Control Review Feasibility Study. We seriously question the advisability of this study and object to the use of ratepayer monies as a source of funding for this study of non-power uses of the FCRPS. (PPC and many others have written separate letters to the Corps on this subject.)

As a result of our review of the Northwest Regional Benchmarking Study, we find that there are significant areas for saving money in the following areas and look forward to the potential for savings from implementation of these initiatives:

- Automation of facilities
- Review of the system-wide water management function
- Sharing of maintenance practices

The customers look forward to meeting more frequently with the Corps and Bureau as we address the above topics.

D. Shift Fish & Wildlife funds from R, M & E to direct-benefit projects.

Customers believe that the $143 million Direct Program funding level as established in the 2005 PFR is fully adequate for BPA to meet its obligations under the Power Act and the Endangered Species Act (ESA). Customers continue to support BPA's initiative to increase the allocation of the Direct Program to 'on-the-ground' projects, like habitat protection and enhancement, tributary passage improvements, and hatchery improvements. This re-allocation serves two worthwhile purposes. First, by moving funds from research, monitoring, and evaluation (R, M &E) to on-the-ground projects, more money is made available to support programs that directly benefit fish. Second, such a re-allocation initiates a timely re-focusing of the region's R, M, & E efforts by reducing redundancies and building efficiencies into those programs.

We have also requested that BPA pursue cost-sharing of R, M, & E in order to better focus ratepayer funds on programs of direct benefit to fish and wildlife. We appreciate the direction that BPA has been taken in both of these areas and—regardless of BPA's financial situation—will continue to advocate for a program based on science and focused on cost-effective efforts to enhance fish and wildlife.

Finally, customers remain concerned about the Corps of Engineers' Columbia River Fish Mitigation funding assumptions. Customers are still unclear about what underlies the Corps' estimate of $1.6 billion to be spent in this program by the time it is completed. A fully formed rationale for these expenditures is necessary before such a large amount of funding is committed.

E. Do not exceed $40 million in DSI benefits.

PPC appreciates BPA's postponement of its decision, until after the conclusion of PFRII, about whether to sign the DSI contracts. Deferring that decision to this point has given BPA and its customers more time and information for assessing whether providing DSI benefits, or at what level, is appropriate.

In its Draft PFR II closeout letter, BPA determined that it would continue to propose the level of DSI benefits at $59 million per year. PPC does not support this level of benefits being provided to the DSIs through contracts for the 2007-11 period. PPC's position on the level of DSI benefits has not changed since PPC's comments on BPA's "straw proposal" for DSI service in March 2005. At that time, BPA had proposed a level of benefits to the DSIs not to exceed $40 million per year. PPC stated that if BPA was resolved to provide benefits, then those benefits should in no case exceed the proposed level of $40 million per year.

Since that time, BPA determined in its June 30, 2005, Record of Decision on Service to the Direct Service Industries for the Years FY07-11 (DSI ROD) that it would offer the DSIs $59 million per year. PPC notes that this amount is roughly a 50 percent increase over the level BPA presented in its straw proposal, and is thus a significant increase above the level at which PPC has stated the levels should be capped.

BPA's decision to offer the DSIs $59 million per year is not justified. As explained below, BPA appears to have changed its stated criteria for determining the appropriate level of DSI benefits since the June 30, 2005, DSI ROD. In that document, BPA assured customers that it would reconsider whether $59 million per year was an appropriate level of benefits for the DSIs during the FY07-11 period, in light of a likely increase in the operational costs of the FCRPS flowing from litigation over the 2004 Biological Opinion.[1] The DSI ROD clearly set out the standard by which BPA would undertake such a review. It explained:

> On June 10, 2005, the United States District Court for the District of Oregon issued an injunction that, if sustained on appeal, will likely greatly reduce the amount of water available this summer for hydroelectricity production. . . . *If this injunction is sustained on appeal, and especially if summer spill along the lines ordered in the injunction is made a regular*

[1] *See, e.g.*, DSI ROD at p. 26 ("BPA will review its decision . . . after the cost impact of the June 10, 2005, injunction becomes more clear . . . . A decision to reduce the amount of service benefits . . . up to and including a decision not to serve any aluminum smelter load, is possible.").

> *part of river operations, the rate impacts would be of extreme concern, and BPA may seek offsetting cost reductions.*[2]

BPA acknowledged, therefore, that its proposed level of benefits may indeed *not be appropriate* if 1) the June 10, 2005, injunction was sustained on appeal, and 2) summer spill along the lines ordered in the June 10, 2005, injunction were made a regular part of river operations. Subsequent to the DSI ROD, both of these conditions were realized—the Ninth Circuit Court of Appeals affirmed the District Court's spill injunction, *and* the District Court, on December 29, 2005, ordered river operations that are very similar in cost to what the June 10, 2005, injunction cost. PPC is unaware of any information indicating a likely return to a more flexible operating system.

However, in its draft closeout report, BPA offers no meaningful explanation of how the level of DSI benefits was considered in light of these stated criteria. Instead, BPA states:

> The additional review time has provided an opportunity to consider the DSI benefit levels in *light of more recent information on expected hydro system operations and a more refined understanding of net secondary revenues BPA will achieve during FY06.* In light of discussions in the PFR II and the updated information on expected hydro operations and revenues, BPA proposes to retain the maximum DSI benefit level at $59 million per year.[3]

This explanation is unpersuasive, and seems to indicate a willingness to take secondary revenues that should be available to reduce rates for preference customers and instead use those revenues to provide a subsidy to the DSIs. It also demonstrates that BPA's determination of the level of DSI benefits relied on a different standard than set forth in the June DSI ROD. In sum, BPA seeks to justify retaining the $59 million annual benefit level based on a better-than-expected net secondary revenues forecast for FY06.

This rationale both differs from the criteria stated in the DSI ROD and is a flawed standard for determining the appropriate level of DSI benefits for a 5-year period. BPA well knows that secondary revenues can vary dramatically from year to year. One year (FY06) of good net secondary revenues is not a sound basis for asserting that $59 million per year is a sustainable and reasonable level of benefits.

---

[2] DSI ROD at p. 12 (emphasis added); The DSI ROD also stated that BPA will review this decision prior to contracts being signed pursuant to this ROD based on more current information about the implications of the District Court's decision *and its impact on future hydro system operations*." *Id.* (emphasis added).
[3] Draft Closeout Report at p. 9.

In the draft closeout report, BPA states that "the updated information on expected hydro operations" is a factor that partly supports its decision. Since the "expected hydro system operations" are exactly those feared at the time of the DSI ROD, they do not justify retaining the benefits.

PPC stands by its position that if BPA is intent on providing the DSIs benefits, they should be no more than $40 million per year. If that benefit is not large enough to be of value to the smelters, then BPA must abide by what it recognized in the DSI ROD—that "it is not . . . within BPA's ability, to guarantee any particular level of DSI operations, even minimal levels" since "[w]orld aluminum prices, raw materials costs, and the financial health of the companies are beyond BPA's control and play at least as large a role in the feasibility of smelter operations as power prices."

F. Accelerate implementation of EPIP Phase One and reduce Internal Operations costs by an additional $4 million/year.

PPC commends BPA for its extensive efforts to date in the Enterprise Process Improvement Program (EPIP).

In BPA's "Enterprise Process Improvement: Marketing & Sales Project Report" that was published in February 2006, BPA acknowledges that strategic objectives of "superior customer service" and "a customer-focused culture" direct its efforts. PPC commends BPA for focusing on these two critical strategic objectives and believes these strategic objectives apply to the entire BPA organization and not just to the Marketing & Sales areas.

During PFR II, BPA has continued to confirm its early estimate of savings from EPIP Phase One studies and its assessment that early process-improvement efforts should be limited to $8 Million/year on average for FY 2007-2009. BPA estimates that power-cost savings from EPIP in the $11 million to $12 million annual range should be achievable over time, but not by FY 2007. BPA also states that some of the EPIP process-improvement activities will take three to five years to complete.

PPC recommends that BPA move ahead as quickly as possible to implement all the process improvements and savings that have been clearly identified and documented in the EPIP Phase One reports. BPA has expended considerable effort in completing the six reports in EPIP Phase One. Timely and effective implementation over 1-2 years, rather than a 3-5 year timeframe, is critical to gaining more efficiencies in each of the six areas. PPC recommends that BPA include additional savings of $4 million/year to the early estimate of $8 million/year and that a total of $12 million/year for EPIP savings be included in

BPA's Final Proposal. We believe this recommendation is further bolstered by the fact that EPIP Phase Two and Three will also be completed in the near future and will produce additional savings for BPA's Power Business Line, beyond those associated with the $11-12 million quoted above.

G. Adjust conservation target by incorporating utility-funded projects, as appropriate.

We support the creation of a system for utilities to report the additional conservation they are achieving, and we hope that this information will be used to adjust BPA's target for conservation if it shows utilities are pursuing more than their share of the Council's regional conservation target. At this point in time we do not support any changes to the budget for BPA's conservation rate credit program. There are new requirements of the program, and these may prove very challenging to comply with. We should first see how successful this program is in practice before budget changes are incorporated.

A related concern involves how future conservation achievements (post 2006) will be treated in the post-2011 world. The Regional Dialogue Process has not officially come to a close, so it is difficult to say whether there will be disincentives to do conservation as a result of the decisions made in that process, but we encourage BPA to endeavor to avoid such disincentives.

H. Remove Fourmile Hill project from this rate period, model the facilitation budget through NORM, and initiate new facilitation funding process.

We support BPA's decision to remove from the FY09 renewables budget the costs associated with the Fourmile Hill Geothermal project. In addition, we are encouraged by the change in how BPA now proposes to treat its facilitation budget in rates FY07-09. It better reflects the uncertainty at this point regarding actual usage of the funds available to utilities for renewable facilitation. We want to start the process with BPA to determine how best to use these funds.

As with conservation achievements post-2006, we are concerned about how utility-developed renewable resources will be treated in post-2011 world. We hope that as BPA refines its Regional Dialogue closeout documents, it will avoid creating disincentives to utility-developed renewable resources.

I. Include customers in the Council's budget-planning process.

The customers intend to become more active in the review of the Council's budget before it enters the realm of BPA cost recovery. During the public Council budget-review period, we will request that the Council present to the customers its

proposed budgets at the ongoing BPA financial-review meetings that are held at PPC.

J. Initiate on-going examination of forecasted budgets, with appropriate customer participation.

In both the current PFR process and its predecessor, we have found that some areas we might think would be ripe for additional cost efficiencies are actually less flexible as the rate period nears. From this we conclude that a cost review for the next rate period (FY10-11) should get underway sooner than mid FY08. However, because *other* areas *are* ripe for change with short notice prior to the start of a rate period, we encourage an additional examination of the FY10-11 costs in FY09 during the rate case (similar to the PFR II process). Similarly, we would like to see the promised capital program process begin this summer and offer customers with sufficient opportunity for debate, discussion, and comment before capital commitments are made.

In addition, in the next few years BPA will be negotiating and signing new, long-term power contracts with preference customers that will commence service in the post-2011 period. BPA and preference customers will be able to make more informed decisions if the budget process for the post-2011 period is started at the earliest possible date. Doing so will allow customers to understand the spending trade-offs and participate in the decisions regarding BPA's spending commitments, which will drive the level of BPA's rates in the post-2011 period.

In conclusion, thank you for conducting a constructive PFR II process, and for considering these recommendations and comments for achieving even more fruitful results. If you have any questions, please feel free to contact me or Annick Chalier, achalier@ppcpdx.org.

Sincerely,

Marilyn Showalter
Executive Director

From: Wright,Stephen J (BPA) - A-7
Sent: Friday, December 19, 2008 9:33 AM
To: Oliver,Stephen R (BPA) - PG-5; Ex 6 : Rapacz,Andy (BPA) - PGC-
Ex 6 Ex 6
Cc: Ex 6
Subject: RE: CGS Condenser Tube decision - Economic Stimulus??

In addition to our conclusion in yesterday's conversation I agree that this is not an appropriate stimulus item and is something we should just move forward with.

From: Oliver,Stephen R - PG-5
Sent: Thursday, December 18, 2008 12:38 PM
To: Ex 6 Rapacz,Andy - PGC-RICHLAND; Wright,Stephen J - A-7; Ex 6 Ex 6
Cc: Ex 6
Subject: RE: CG5 Condenser Tube decision - Economic 5timulus??

Andy and I discussed this over the past couple of days and arrived at the same place as Paul. The only thing that caused us any pause, is that we have expressed significant concern that EN remain within budget and have been particularly interested the condenser project. This modification could/would likely(?) create the need for EN to request a mid year budget increase that we would need to approve, and it really doesn't create jobs. All that being said, it has a rapid return on investment and seems like a straight forward decision.

Stephen R. Oliver

From: Ex 6
Sent: Thursday, December 18, 2008 12:29 PM
To: Rapacz,Andy - PGC-RICHLAND; Wright,Stephen J - A-7; Ex 6 Oliver,Stephen R - PG-5; Ex 6
Ex 6
Cc: Ex 6
Subject: RE: CGS Condenser Tube decision - Economic Stimulus??

It's a no-brainer economically if we believe the numbers and if there is no incremental risk created by going to smaller diameter. I think we should find the $ promptly and not dink around with economic stimulus on something so small and easily justified on its own and clearly within our capability.

From: Rapacz,Andy - PGC-RICHLAND
Sent: Wednesday, December 17, 2008 4:28 PM
To: Wright,Stephen J - A-7; Ex 6 Oliver,Stephen R - PG-5; Ex 6 Ex 6
Cc: Ex 6 Rapacz,Andy - PGC-RICHLAND
Subject: CG5 Condenser Tube decision - Economic 5timulus??
Importance: High

All:

During the 12-15-08 condenser steering committee meeting, I was asked about the availability of "economic stimulus" funds (there was quite an article in the Tri-City Herald over the weekend suggesting the new administration may be making economic stimulus monies available to BPA to help stimulate the economy). The inquiry was made in the following context.

EN has a technical decision to make on a relatively short fuse (two to three weeks), regarding selection of condenser tube size for the new condenser.
The decision has been narrowed down to selection of one of two possible tubes sizes; one (1) inch and 7/8 inch. The 1" tube condenser configuration costs less because the number of tubes is less, therefore there is less titanium used and fewer tubes manufactured. However, the 7/8" tube size results in slightly improved overall efficiency, such that generation

will be 2.7 MWe more compared to the 1" tube size [the total tube surface area and heat transfer capability is greater with the use of the 7/8 " tube design]. Separate from this tube decision, it is projected that the new condenser will produce at least 12 MWe more than the existing design, and incentives/penalties are being built into the vendor's contract. (the existing CGS condenser has 1" tubes)

As part of the decision process, EN has asked for BPA input on the cost vs. efficiency tradeoff, and the availability of economic stimulus funds. EN has requested feedback from us by December 29th. The business case analysis shows a favorable payback time of 5 years for the additional cost of the 7/8" tubes. EN is looking at other internal funding options and trade-offs, but I agreed to advance to BPA management both the tradeoff question and the particular question of the availability of economic stimulus money.

The complexity of this decision does not seem to rise to the level of producing an agency decision framework template, particularly given that this is an EN decision. The facts are the same as presented here. The tube size decision needs to be provided to the module manufacturer soon in order to support and maintain the module design schedule. The Pro's and Con's of each tube size are summarized below.

I'm looking for some feedback on this issue. Right now I'm leaning towards telling EN that our input is that the $3M investment for 2.7 MWe on a short payback is well worth the investment; but at this time there are no economic stimulus monies available, so EN should pursue other paths (under runs, contingency, other scope reductions, other project deferrals, etc.) to fund the small tube option.

I'm very interested in your thoughts and feedback,
Thanks,
- Andy

One (1) inch tubes:

Pro's

- Project cost is $3 M dollars less than the 7/8 inch tube option.
- Helps bring the condenser project current estimate of $131 M closer to the $106 M budgeted in the long range plan.

Con's

- Less generation (calculated to be 2.7 MWe) due to lower efficiency.
- Lower project costs ($3 M) provides less potential economic stimulus to US economy.

Seven-Eights (7/8) inch tubes:

Pro's

- More generation (calculated to be 2.7 MWe) due to higher efficiency.
- Payback is estimated at 5 years.
- Increased generation is totally "green and carbonless"; no additional fuel is used since this is an efficiency improvement
- Higher project costs ($3 M) potentially provides more economic stimulus to US economy.
    - Economic stimulus impact will be related to the purchase of more titanium and fabrication of additional tubes.

Con's

- Cost $3M more, making it more difficult to reduce the project's cost estimate of $131M to the $106M target budgeted in the long range plan.
- Will be difficult to actually measure a 2.7 MWe increase in electric output.
- Economic stimulus will most likely not be seen in the northwest, or by the Pacific Northwest rate payers.

From: Ex 6
Sent: Wednesday, January 10, 2007 9:52 AM
To: Rapacz,Andy (BPA) - PGC-RICHLAND
Cc: Ex 6 Ex 6 Ex 6
Ex 6 Ex 6
Subject: RE: CGS Condenser replacement Business case analysis - SAVE

Andy,

The attached file has monthly average (flat) prices for CY07-CY15. There are two Alternatives. The first alternative is very consistent with the assumptions we used in the recently finished rate case. The second alternative is more of an internal view of what we think the market is trading for at the current point in time. Alt 2 is higher than Alt 1 but I'm not sure I would call it a "high" case. If you would like a "high" case I can develop one but it would not be done until tomorrow.

[redacted]

From: Rapacz,Andy - PGC-RICHLAND
Sent: Tuesday, January 09, 2007 3:34 PM
To: Ex 6
Cc: Ex 6 Ex 6 Ex 6
Subject: RE: CGS Condenser replacement Business case analysis

Ex 6,
I think we should be ok with an average (flat) rate. We will be using this to calculate costs of the Plant being out of service for a significant number of days, so an average should work OK.

(If you've got a file by LLH & HLR, maybe you could send that up later, we'd just be interested in looking at it, but we won't use all that input in our economic analysis.)

Thanks,
-= Andy

From: Ex 6
Sent: Tuesday, January 09, 2007 3:17 PM
To: Rapacz,Andy - PGC-RICHLAND
Cc: Ex 6
Subject: RE: CGS Condenser replacement Business case analysis

Andy,

Do you want prices by HLH and LLH ? Or is average (flat) o.k. ?

Ex 6

From: Rapacz,Andy - PGC-RICHLAND
Sent: Monday, January 08, 2007 2:36 PM
To: Ex 6 Ex 6

Cc: Ex 6 Ex 6 Ex 6
Subject: RE: CGS Condenser replacement Business case analysis

Thanks Ex 6 , what you've said makes sense.
Friday (as it was getting late in the day) I found myself wondering if somehow we'd lose on both the lost revenue and replacement cost front. But I see the logic of your explanation.
No further questions at this point, thanks for all you help on this issue.
- Andy

From: Ex 6
Sent: Monday, January 08, 2007 12:04 PM
To: Rapacz,Andy - PGC-RICHLAND; Ex 6
Cc: Ex 6 Ex 6 Ex 6
Subject: RE: CGS Condenser replacement Business case analysis

Andy, as I was reading through the below email message I had a question about your #1. You state that you would need a price for both replacement power and lost revenue. I have two thoughts on this - first the price would be the same for both as you would assume that the value of the energy would be what the forecasted market price is and it does not matter if you are using the energy to serve existing load or selling the surplus power into the market.

My second comment is that you only count the value of the lost energy once not twice. You can characterize the loss of energy as forgone revenues OR replacement power but you do not take a double hit. If you characterize it as replacement power you buy the energy at the forecasted energy price and then you are back to where you were (MW wise) when CGS was operating. You now have that purchased power to either serve existing load or sell on the market. Or you can look at it this way - if you do not need the energy to serve existing load (the system is load/resource balanced) then you do NOT go out and "replace" the energy - you just forego the revenue that you would have received from selling the CGS MW's. Either way you are only out the value of the energy one time - not two.

Please let me know if I misinterpreted something or if you have additional questions. Ex 6

From: Ex 6
Sent: Monday, January 08, 2007 7:38 AM
To: Ex 6
Subject: RE: CGS Condenser replacement Business case analysis

See Andy's question about power prices, would Ex 6 be the right guy?

From: Rapacz,Andy - PGC-RICHLAND
Sent: Friday, January 05, 2007 3:31 PM
To: Oliver,Stephen R - PG-5; Ex 6 Ex 6
Cc: Ex 6 Ex 6 Ex 6 Ex 6
Rapacz,Andy - PGC-RICHLAND
Subject: CGS Condenser replacement Business case analysis
Importance: High

Steve, Ex 6 and Ex 6

Energy Northwest has began an evaluation of replacement options for its leaky main condenser. We have meet with EN on two occasions to discus a study that was recently completed by Sargent & Lundy for Energy Northwest and the associated business cases being developed by EN staff. The EN business cases are evaluating; retubing the existing condenser or a modular bundle replacement as compared to a base case of continuing to operate as in the past year (battling leaks) and delaying the replacement of the condenser for six years.

In support of the business cases we have been asked to provide information in regards to power prices and the timing (time of year for the outage). In the past we would have gone to Ex 6 for power cost numbers but today we need some direction as who is the right person to go to for this information and the timing of the outage?

Background: the retubing estimated duration is 68 days (normal refueling outage of 35 days plus an additional 33 days) and the modular replacement is estimated at 120 days (normal refueling outage of 35 days plus an additional 85 days) with the base case assuming a normal spring refueling outage of 35 days.

1. What price should we tell EN to use for replacement power during the extended refueling outage and what price to use for lost revenue during the extended outage? Also do we have any analysis or documentation to back up the pricing info we would provide? EN is using $40/MWh in their draft business cases. (We're assuming we'd take a double hit of 1) lost revenue, plus, 2) cost of replacement power.)

2. The second question is when should the extended refueling outage occur (time of year)? Currently EN business case assumes the replacement would be planned for the spring of 2009 but could slip to 2011 or 2013 based on availability of materials and amount of engineering support needed. Assuming a normal refueling outage starts about 15 May, do we back up the refueling outage start by 33 days to 12 April for the retubing option and by 85 days to 19 February for the modular replacement? (to avoid getting into the July [hot] time frame with an outage)

3. And to support the base case (operation with leaks) what range for the cost of replacement power should be used if CGS took a forced outage (off line) mid cycle to fix a leak (worst case August or January)? We assume if they just did an online repair (a 60% down power for three days) we would take it out of inventory supplemented with some minimal buying unless the system as a whole is capacity limited.

And as always, time is of the essence. EN would like an answer early next week if possible (January 9?). Our understanding is the EN Senior management team will be briefed on this next Thursday.

- Andy & Ex 6

From: Oliver,Stephen R (BPA) - PG-5
Sent: Thursday, May 08, 2008 4:51 PM
To: Wright,Stephen J (BPA) - A-7; Ex 6 Rapacz,Andy (BPA) - PGC-RICHLAND; Ex 6
Subject: RE: CGS capital - run the CGS steam condenser decision through our capital allocation process

Thanks. We will work with Mike to take the condenser investment through the capital review process.

Stephen R. Oliver
Vice President, Generation Asset Management
Bonneville Power Administration
Ex 6

From: Wright,Stephen J - A-7
Sent: Thursday, May 08, 2008 4:03 PM
To: Oliver,Stephen R - PG-5; Ex 6 ; Rapacz,Andy - PGC-RICHLAND; Ex 6
Subject: RE: CGS capital

When power, transmission or corporate approve a budget the specific actions still go through a captial review process. This is a capital expenditure in excess of $100 million that the agency will be on the hook to repay. We should subject it to the same rigorous review we expect of other capital allocation decisions using the standard procedures we have developed for making capital allocation decisions.

As to where we would go with this, I think it would be good to establish the precedent we review CGS capital decisions the same as other capital decisions. I'm reasonably confident the conclusion will be that the steam condenser needs to be replaced, although it would be good to know if it didn't and if not why not. The more interesting question is the choice between the two replacement options. If by chance we come to a different conclusion than ENW about which option to choose, then we we would face the question of how we pursue our conclusion.

Over the coming year or two I expect the level of scrutiny our preference customers are going to place on this decision is going to grow and they will want to know where we stand. I want us to be in a position of having performed a thorough due diligence review consistent with what we would do for a hydro or transmission investment. I also want to be in a position that if the facts change (e.g. the cost of the condenser replacement option being pursued is altered in a substantial way), that we are in a position to understand better what our reaction should be.

I am assuming it is possible to go through this review based on currently available information and therefore do not need to engage ENW unless we come to a conclusion that varies from the course ENW is on.

From: Oliver,Stephen R - PG-5
Sent: Thursday, May 08, 2008 2:24 PM
To: Wright,Stephen J - A-7; Ex 6 Rapacz,Andy - PGC-RICHLAND; Ex 6
Subject: RE: CGS capital
Importance: High

Steve;

I don't disagree that we have this option, but I would like to offer the following thoughts:

- We have spent a significant amount of time on the issue of proceeding with the condenser replacement. PGC has reviewed the Sargent & Lundy and Huron reports and have asked/answered questions (documented); and ultimately has been invited into EN meetings and briefings including the Condenser Replacement Team meetings led by Ex 6 (In fact there is one today at 3:30 PM that Andy will be attending.)
- After our internal review we've agreed with EN that we should go ahead with the replacement. We tested this with other non-EN nuclear experts at your request, and we've consistently heard that the replacement was very likely

warranted, (however the costs have been surprising to some.) We stated our support for it in the budget letter to EN last year.

- We've told EN we're past questioning it. We've told them we want to work with them to reduce costs of the task, shorten the outage, and make sure it fits in with the FCRPS operations needs as much as possible. I reiterated this to the Board of Directors just two weeks ago. We've also said this to the PPC and PRB.

Given this past course of events, I am not clear where we would go with the BPA capital review? As I understand your proposal it would be to verify the Huron analysis. If this is the objective, it might be more appropriate to hire another nuclear engineering firm to independently review both the S&L and Huron reports. Even if we took this step, we will have to manage how we explain the potential change of our position regarding our prior approval for proceeding with the project.

Thanks for continuing the dialogue on this topic.

Stephen R. Oliver
Vice President, Generation Asset Management
Bonneville Power Administration

Ex 6

From: Wright,Stephen J - A-7
Sent: Thursday, May 08, 2008 11:30 AM
To: Ex 6 Oliver,Stephen R - PG-5; Rapacz,Andy - PGC-RICHLAND; Ex 6
Subject: RE: CGS capital

We could look at it on the same basis as is in the Huron analysis done for ENW as a way of testing their analysis. That includes three options, no action, and two alternatives for steam condenser replacement.

From: Ex 6
Sent: Thursday, May 08, 2008 11:27 AM
To: Wright,Stephen J - A-7; Oliver,Stephen R - PG-5; Rapacz,Andy - PGC-RICHLAND; Ex 6
Subject: RE: CGS capital

But I thought we had made the decision.

From: Wright,Stephen J - A-7
Sent: Thursday, May 08, 2008 10:07 AM
To: Oliver,Stephen R - PG-5; Ex 6 ; Rapacz,Andy - PGC-RICHLAND; Ex 6
Subject: CGS capital

Do we think we could run the CGS steam condenser decision through our capital allocation process? It's a huge decision and it seems like it needs a due diligence determination from us. All other capital decisions go through this process.

From: Ex 6
Sent: Friday, July 11, 2008 8:23 AM
To: Oliver,Stephen R (BPA) - PG-5
Cc: Rapacz,Andy (BPA) - PGC-RICHLAND; Ex 6 Ex 6

Subject: Preliminary report to CAB on CGS condenser replacement

Steve:

As you probably know, the Agency Capital Project Review Team (ACPRT) is now reviewing the CGS condenser replacement project. Attached is a 1-page progress report that is being forwarded to CAB members today in advance of its meeting on Wednesday. No discussion is planned at this CAB meeting -- the progress report is for info purposes only.

We are scheduling time with you to review our preliminary findings (week after next).

Progress Report on ACPRT Review
CGS Condenser Replacement

The Agency Capital Project Review Team (ACPRT) is reviewing the business value of Energy Northwest (ENW)'s condenser replacement project for BPA. The review is focused on the financial implications of four alternatives that were considered in a Huron Consulting Group study commissioned last winter by ENW:

1. Titanium modular replacement installed in 2011;
2. Titanium modular replacement in 2015;
3. Titanium retube with new tubesheets in 2011; and
4. Titanium retube with new tubesheets in 2015.

The Huron Study concluded that the Titanium modular replacement – 2011 alternative was preferable because it offered greater technical and operational benefits than the titanium retube alternative and because it was financially advantageous to proceed sooner rather than later. ENW included the modular replacement – 2011 alternative in its FY 2009 budget, which the ENW Board approved and BPA non-disapproved in late spring 2008. This alternative is also reflected in the spending levels that BPA proposed in the Integrated Program Review.

The Huron Study process was largely closed to BPA and other stakeholder review until it was completed in February 2008. The Study's analytical approach, assumptions, and results were documented, however, and the Study serves as the primary source of financial data for the ACPRT's review. Huron evaluated the financial costs and benefits of the alternatives using the same life cycle costing/net present value method that Bonneville now uses to evaluate other capital projects. At the Administrator's direction, the review is being conducted with currently available materials; no request has been made for supplemental information from ENW or Huron, and no business case was requested or submitted. PGC is a full partner in the review.

We anticipate completing the review by the first week in August. Power Services will be briefed and comments considered before findings are advanced to the CAB. The ACPRT's report will cover the (1) financial and risk implications of the project alternatives and (2) a high-level assessment of ENW's capital decision practices with regards to BPA's asset strategy and standards for capital project valuation.

The ACPRT has replicated the financial analytics performed by Huron, and issues have been found that affect the calculation of net present values for the four alternatives. For example:

- The discount rate that Huron used to determine the net present value of the alternatives was 6.5 percent (reflecting ENW's weighted average cost of capital), rather than the risk-adjusted discount rate that BPA has mandated for Federal hydro and all other capital projects in Power Services.
- Incremental cash flows for each alternative were not developed by comparison to a reference, or "no action" case. All other things equal, the net effect of this is that long-term benefits were overstated
- Replacement power costs (due to lost generation) and savings were not fully accounted for, nor was replacement power cost uncertainty.

We are re-running the analytics now, and offer no findings or conclusions at this point.

From: Ex 6
Sent: Monday, August 20, 2007 1:18 PM
To: Oliver,Stephen R (BPA) - PG-5; Ex 6
Cc: Rapacz,Andy (BPA) - PGC-RICHLAND; Ex 6
Subject: FW: Delay in condenser replacement

Follow Up Flag: Follow up
Flag Status: Flagged

Steve and Ex 6

The text below is Ex 6 and my response to Steve Wright's. question. Look it over, check that it is on target, add your comments and forward it on to Steve Wright.

Thanks

Ex 6 Ex 6

Officially, we have heard nothing from Energy Northwest, which is in line with their current policy of not providing information to BPA until it is a finished product. Employees are very guarded in talking with us condenser issues. Un-officially we have determined the business case for for modular replacement has been drafted and is ready for submittal to the engineering manager. Nothing concerning this has been prepared for PHC or EAC which are the decision making committees for all large projects. Therefore no official decision has been made within EN as to which replacement type will be implemented or when. We have not been given a copy of the draft business case to review.

With regards to the outage, two items to report. First, the titanium tube replacement "pull test" failed. This means the mock-up test for mechanical connection failed and indicates the replacement of individual tubes with titanium is not a viable option. For tube replacement to be a viable option the addition of replacement tube sheets and divider plates will also have to be considered which will drastically increasing the cost and outage duration. Second, an experienced Bechtel employee Ex 6 was hired to investigate the plant configuration and determine several conceptual models for modular replacement of the condenser tubes. Rumor has it Ex 6 has determined several methods for decreasing the outage duration for modular replacement to the order of 70-75 days. The old estimate was 120 days with a confidence of a factor of two.

From the old business case provided by Energy Northwest this past spring, modular replacement with titanium tubes would have a capital cost of Ex 5 and the outage duration was estimated at 120 days vs. 68 for retubing. Note, we were informed that the outage estimate for modular replacement was considered a very rough estimate and could be off by a factor of two, and that they would need to validate this option if pursued.

From: Wright,Stephen J - A-7
Sent: Friday, August 17, 2007 6:40 PM
To: Ex 6 Oliver,Stephen R - PG-5; Rapacz,Andy - PGC-RICHLAND
Subject: Delay in condenser replacement

One thing Ex 6 and Ex 6 made a big deal about yesterday that I was not familiar with is that during the last outage they learned enough to conclude they will need to go with modular replacement and as a result the replacement will be delayed. What do we know about this?

From: Ex 6
Sent: Friday, March 16, 2007 6:32 PM
To: Ex 6 Ex 6
Cc: Rapacz,Andy (BPA) - PGC-RICHLAND
Subject: Condenser Letter Transmital to EN
Attachments: Condenser Replacement-ajr.PDF

Ex 6 Ex 6,

Please find attached an advanced copy of questions concerning the condenser replacement project. Thanks.

Ex 6

Ex 6
Bonneville Power Administration
Ex 6

Department of Energy

Bonneville Power Administration
Mail Drop 1399
P.O. Box 968
Richland, Washington 99352-0968

POWER SERVICES

March 16, 2007

In reply refer to: PGC/Richland

Mr. W. S. Oxenford, Vice President
Technical Services
Energy Northwest M/D PE04
P.O. Box 968
Richland, WA 99352-0968

Dear Mr. Oxenford:

The Bonneville Power Administration (BPA) understands that Energy Northwest (EN) has decided to replace the main condenser at Columbia Generating Station (CGS) in FY 2009 using a re-tube with titanium tubes approach. The options considered included use of various tube materials, and whether to re-tube or use modular replacement methodology. This project represents a large capital and expense impact on BPA and the region, and the condenser replacement effort itself will require an extended outage beyond the normal refueling outage length. The option that EN has selected currently requires approximately 33 additional outage days to a planned refueling and maintenance outage without condenser replacement. The cost of an additional 33 days of outage is approximately $35 million. This expense cost (not capital) will have an immediate impact on our rates that was not planned for in this 2007-2009 rate case.

BPA acknowledges EN's review of the options identified by Sargent & Lundy in their study and of the cost benefit analysis developed for those options. We would like to ensure we have clarity and a common understanding of the facts and options considered when EN reached its recommendation. With that in mind, we request that you respond to our questions below to enable us to finalize our position and take action on the condenser project, which we anticipate would occur in the course of our action regarding the FY 2008 CGS Budget.

In addition, we believe that the results of the fuel inspection and condenser eddy current testing effort, both of which are scheduled to be performed during the R-18 outage (May 2007), will provide key information regarding the need for the condenser replacement at this time. Although we would agree that the present EN recommended course of action has its merits, we would like the information requested below in order to have a collaborative discussion with you regarding whether there are timing options to condenser replacement that assure high plant reliability/integrity/safety, but are more cost effective for our regional rate payers. We would like to have this discussion prior to our action on the CGS FY 2008 Budget.

1. What is the estimated end-of-life (using the HEI methodology) for the current condenser assuming continued proper maintenance? Given the 40-year design life of the existing

condenser, and the full eddy current testing scheduled during Refueling Outage R-18, would these results (as well as the R-18 fuel inspection results) provide valuable information that either would affirm the current recommendation or indicate that the timing of the condenser replacement could be re-evaluated?

2. What are the projected costs for continuing regular refueling outage maintenance on the existing condenser, and a new condenser?

3. What is the estimated life of the new condenser, including a comparison with industry experience that supports the estimate? What is the degree of confidence the new condenser will last to the end of plant life in 2043, assuming license extension is implemented?

4. What is the expected plant energy loss due to condenser driven de-rates during summer months with a new re-tubed titanium condenser?

5. Based on industry experience, what is the projected number of tubes that will require plugging for the new condenser through end of plant life, assuming license extension is implemented, and the corresponding annual energy losses expected due to condenser driven de-rates? What is the likelihood and number of infant mortality tube failures in the new condenser?

6. What is the ability of the new condenser design to support future power up-rates, if up-rates are implemented? What are the other plant equipment upgrades and associated costs that could be implemented to mitigate power de-rates from an up-rated power level condition?

7. Please provide a summary of the number and cycle of occurrence of condenser tube failures at CGS separated into the following causal categories: debris induced, steam impingement, vibration induced, general erosion, stress corrosion cracking and others.

8. Describe the actions taken to address the root cause of foreign material exclusion (FME) problems documented in PER No. 204-0811, and how these actions are expected to prevent re-occurrence of foreign material caused leaks in the new condenser.

9. Please provide a summary of the number and cycle of occurrence of fuel failures at CGS separated into the following causal categories: foreign material induced fuel fretting, copper interaction with fuel cladding, condenser leakage (feedwater contaminants) and others.

10. Please provide the projected number of fuel failures between now and end-of-life (as estimated in question 1) of the current condenser separated into the following categories: foreign material induced fuel fretting, copper interaction with fuel cladding, condenser leakage (feedwater contaminants) and others. Also, provide the projected number of fuel failures expected during the lifetime of the new condenser separated into the same categories.

11. What are the estimated levels of feedwater copper before and after condenser tube material replacement? Will the copper levels after tube replacement meet all industry guidelines?

12. What is the estimated dose reduction relative to the collective radiation exposure (CRE) performance indicator, separated into the following categories: dose reduction due to condenser tube material replacement, dose reduction associated with chemical decontamination during refueling outages, dose reduction associated with the cobalt reduction effort and dose reduction associated with fewer tube leak repairs? What is the estimated CRE performance indicator after R-19 and after R-20 if the condenser is not replaced and the cobalt reduction efforts proceed and chemical decontaminations are conducted as part of future refueling outages?

13. Describe EN's enhanced ability to detect and repair condenser tube leaks and confirm whether this is included in the cost benefit analysis business case.

14. What is the total cost estimate to replace the condenser with the option EN has chosen, excluding the cost of replacement power? Based on the past history of cost increases in major plant projects, including ISFSI, HWC, DEH and FWH replacement, provide the degree of confidence associated with this cost estimate.

15. Please provide a copy of the cost benefit analysis business case for the condenser replacement, including a summary explaining the assumptions that were used and verified in the analysis.

16. Given a net present value of negative $65 million for the chosen replacement option, please describe the offsetting factors, i.e., regulatory commitments, INPO recommendations, etc., that make this a viable project from a cost benefit perspective. Are there any other alternative options, including condenser replacement deferral to end of life estimated in question 1, that result in a less negative, zero or positive net present value?

Thank you for addressing these important questions. If you have any questions about the list above, please contact Phil Smith at 5130 or me at 5752.

Sincerely,

Andrew J. Rapacz

Andrew J. Rapacz, Manager
Contract Generating Resources

cc:
Mr. D. K. Atkinson, Energy Northwest – M/D PE08
Mr. J. V. Parrish, Energy Northwest – M/D 1023

From: Ex 6
Sent: Friday, May 09, 2008 1:53 PM
To: Wright,Stephen J (BPA) - A-7; Ex 6 Ex 6 Ex 6 Ex 6
Cc: Oliver,Stephen R (BPA) - PG-5; Rapacz,Andy (BPA) - PGC-RICHLAND
Subject: CGS Condenser Cost Update for IPR- Worth of Lost Generation

In support of the CGS Condenser Cost Update for IPR and per Steve Oliver's direction the following information is provided:

The worth of the additional lost generation due to the condenser replacement above a normal refueling outage is estimated to be $53 million.

Notes:

- The condenser replacement will occur in spring 2011 (Apr.-Jun.)
- The latest outage length estimate is 75 days starting in early April and finishing in mid June.
- A normal refueling outage is 38 days, the condenser replacement will result in an additional 37 days of lost generation or about 983,000 MWh.
- At an average price of $54 MWh the lost generation is worth about $ 53 million in revenue.

Ex 6

ASME International

The American Society of Mechanical Engineers
Three Park Avenue
New York, NY 10016-5990

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MODULAR CONDENSER REPLACEMENT AT ANO-1 SOLVES OPERATING PROBLEMS AND IMPROVES PERFORMANCE

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ABSTRACT

After 22 years of operation, the condenser tube bundles and waterboxes at Arkansas Nuclear One, Unit 1 (ANO-1) had deteriorated significantly, impairing operating performance, reducing condenser reliability and increasing maintenance cost. An extensive condition assessment performed in 1995 revealed a 34% wall loss on the original Admiralty tubing and an erosion rate of 1. 7% annually. Additionally, Arkansas Nuclear One was considering an 8% power uprate, which would place additional duty on the main condenser. As a result, it was decided to completely reconstruct the four condenser tube bundles serving the two low-pressure turbines at Arkansas Nuclear One.

An evaluation of the available condenser tube materials was performed to determine which material was best suited for service in the single pass, single pressure condenser at ANO-1. All copper based materials were excluded from consideration due to the detrimental effect copper has on secondary chemistry and more specifically steam generator integrity. Titanium and a variety of stainless steel materials were evaluated, and ultimately titanium was selected as the replacement condenser tube material for the rebuilt condenser tube bundles due primarily to its corrosion resistance and extensive operating experience in condenser service. An impressed current cathodic protection system and epoxy waterbox coating was also installed to prevent galvanic corrosion of the carbon steel waterboxes. The cathodic protection system included local alarm indication, to alert plant operating staff of any system malfunction that could result in titanium hydriding. A . comparison of the heat transfer characteristics of the existing condenser design with Admiralty tubes and a new tube bundle design with titanium tubes concluded that a new tube bundle design was required to optimize the condenser performance and accommodate the anticipated 8% power uprate. This paper will discuss the' condenser optimization program from the design stage to final installation.

Further, it was decided to completely shop fabricate these four titanium tube bundles to minimize the site erection schedule. Each bundle measuring over 44 ft (13.5 m) long, over 13 ft (4 m) wide, and nearly 18 ft (5.5 m) tall, weighed 195,000 lbs (88,450 kg). The weight and size of the bundles created a variety of fabrication, transportation and installation challenges that required extensive advanced planning, scheduling and coordination.

The complete installation of the redesigned condenser tube bundles and waterboxes was accomplished during the Fourteenth Refueling Outage of ANO-1 in 1997.

INTRODUCTION

Arkansas Nuclear One, Unit 1 (ANO-1), an 883 Mwe PWR, was licensed for commercial operation in 1974. The original Westinghouse turbine/condenser system consisted of a single-pressure, dual exhaust LP turbine exhausting to two, single pressure, single pass surface condensers.

A condition assessment of the original condenser was performed in 1995 which revealed the condenser had experienced several types of tube degradation during the 22 years of previous service. The failure mechanisms present in the ,condenser included: uniform ID erosion, steam impingement, ammonia grooving, intergranular corrosion, vibration damage, circumferential cracking, localized cor' osion, ID pitting, and mechanical damage. The most significant of these was the circumferential cracking at or near mid-span between support plates. The primary cause for this condition was increased tube vibration due to uniform ID erosion. During this condition

assessment, the average wall loss of the condenser tubes was measured to be 34% less than the originally supplied tube wall thickness. Even more significant, the erosion rate was estimated to be 1.7% annually.

In addition, copper deposition throughout the secondary system from the Admiralty condenser tubing was detrimental to the integrity of the steam generator tubing. Also, the secondary chemistry pH suitable for the Admiralty tubing resulted in higher secondary corrosion rates and more iron transport to the steam generators. Finally, the adverse effects of circulating water contamination was a threat to secondary chemistry limitation and damaging to the steam generators.

After an exhaustive evaluation of all viable alternatives, it was decided that the existing Admiralty condenser tubes and Muntz tubesheets should be replaced with a new tube bundle design utilizing titanium tubes and tubesheets. This evaluation considered numerous other non-copper alloys ranging from 316L stainless steel to AL6XN. The primary factors used to evaluate each material were material compatibility with the site's brackish cooling water, initial and future maintenance costs, plant performance, industry operating experience and probable failure modes (corrosion, under deposit pitting, biological fouling, etc.). It was further determined that this replacement would be accomplished using shop fabricated tube bundles and waterboxes to minimize required installation time. Each tube bundle was to be completely shop assembled and thoroughly tested before being shipped to ANO-1 for installation. In addition to compensating for the difference in the thermal conductivity between Admiralty and Titanium, the replacement condenser design was required to optimize condenser performance at the contemplated 8% power uprate condenser duty. Refer to Table 1 for comparative performance requirements.

Also, the physical size and weight of the tube bundles presented the project with many transportation and installation challenges. These challenges necessitated an extraordinary level of coordination between the various entities involved in this condenser tube bundle and waterbox replacement project. The limited installation window available with the scheduled refueling outage further enhanced this level of coordination.

MODULAR TITANIUM BUNDLE DESIGN

The design optimization program had to consider the required 8-pereant power uprate utilizing the existing dreulating water system while producing an *efficient* turbine output The difference between the hestYtransibr coefficients of the original Admiralty tubing and the new rolled/welded I inch (25. mm) diameter, 24 BWG and 22 BWG titanium tubing (ASTM B338, Or. 2) provided a significant challenge in the design of the new condenser bundles.

With the external envelope of the condenser intact, the condenser design optimization had to consider several key elements. Assessment of the existing circulating water pump capacity against condenser backpressure with the new bundle design was of utmost importance. Multiple cases of thermal/hydraulic design combinations were analyzed balancing the circulating water system, optimizing pumping efficiency, cooling water usage, MW output, and hardware cost. Evaluation of the space constraints within the existing condenser provided the final interface requirements with the new modules. Spacing of the new support plates was reduced considerably with the lighter gauge titanium tubing in order to alleviate tube vibration during full load operation with one bundle out of service.

New condenser waterboxes were designed to facilitate installation, improve flow distribution to the tubes, and minimize pressure drop. This was the critical interface piece between the new condenser bundles and the existing circulating water piping in the plant A sophisticated Finite Element Analysis program verified the structural integrity of the new waterboxes, and subsequent shop hydrostatic testing confirmed the results. Waterboxes were equipped with an impressed current cathodic protection system and internal epoxy coating to prevent galvanic corrosion of the carbon steel surfaces.

The new titanium tube bundles were more erosion resistant, with better deaeration capabilities. However, their lighter weight in spite of a more compact tube field necessitated a thorough uplift analysis to evaluate the integrity of the existing anchor bolts and the necessity for additional anchoring.

The condenser bundles were fabricated to high quality standards in a controlled shop environment Several shop mock up tests were performed to determine the optimum tube pull out load, and the required wall reduction for the rolled tubes. Prior to rolling and welding, 100% base line eddy current testing of the tube bundles was completed. Results of this test were stored on several tapes and were submitted to ANO. Future in service eddy current examination can be made and compared to base line results to determine wear.

All tube ends were rolled and welded using automatic welding machines. Tube welds were checked for integrity using dye penetrant testing, and also vacuum leak testing to verify the integrity of the tube joints and the entire tube length. Once pronounced sound, condenser modules were wrapped in specially designed tarps and shipped to the site.

Figure 1 details the overall size and weight of one of the four replacement condenser tube modules, and Figures 2, 3, and 4, show the bundle manufacturing process at several stages.

BUNDLE TRANSPORTATION

With the massive size and heavy weight of each titanium tube bundle, transportation logistics became a significant issue.

The Departments of Transportation in several states had to be contacted to assure that roads, highways, and bridges would be available for this transport Special permits and full time escorts were required from the manufacturing plant to the job site to assure safety and security of all involved. Limited height was a critical element throughout the transportation route. Rail transportation was out of the question due to oversize weight and dimensions, and truck transportation was the most viable alternative at the time of shipment Figure 5 shows how the trunnions welded into the bundles were supported by the longitudinal "r beams, and Figure 6 shows the special trailer arrangement developed for this transport purpose. Essentially it could be celled a "double-pole" trailer where two specially designed "r beams almost 15-f (4.6m) apart supported the tube bundle suspended between them. The special trunnions supported the tube bundle, reducing its overall height above the road as much as possible. Since only one such special trailer was built, it had to make four round trips from the manufacturing facility to ANO to complete the delivery project. Waterboxes were shipped separately to maintain the overall schedule and to keep bundle transportation within allowable size and weight limitations.

PROJECT INSTALLATION

The installation phase of the condenser tube bundle and waterbox replacement project presented numerous challenges for the project team.

The first challenge was completing the condenser replacement within the scheduled refueling outage duration of 42 days and 1 hour. This limitation affected every decision made on the project from the beginning of the project.

The second challenge was the physical location of the condenser, which was 19 feet below ground level. The only existing access to the area was through a condenser tube pull pit, which was approximately 10 feet shorter than the condenser tube bundles. To provide access to the existing condenser shells, a large opening was made in the side of the turbine building, which included the removal of structural steel, interference piping and electrical interferences. Figure 7 shows the bundle transportation at the site, and the available access route to the condenser portal. Figures 8 and 9 shows the opening in the turbine building wall and the elevation of the existing condenser shells relative to ground level. Figure 10 shows insertion of one of the tube bundles into the turbine building.

The third challenge was the proximity location of several interferences outside the turbine building which greatly restricted access to the condenser area. These interferences include the main transformers and startup transformer #2 and associated electrical buss ducts and 500 KV and 261 KV overhead power lines (Fig. 7). These interferences precluded the use of a large crane to rig the tube bundles into the tube pull pit. A specially designed gantry crane capable of lifting, translating and rotating each tube bundle was designed and assembled over the tube pull pit (Fig. 9). The gantry included a specially designed lift frame that allowed the load to be shifted while still suspended to locate center of gravity and ensure that the tube bundles were kept level during the rigging operation. The gantry also included a hydraulic turntable for better control of the tube bundles while the bundles were rotated.

The fourth major challenge was the limited access to the condenser inside the turbine building. To get the new tube bundles and waterboxes into . the condenser, a large track was assembled in the turbine building basement and extending into the condenser shell (Fig. 8). Specially designed hydraulically powered rollers were used in a load equalizing arrangement to ensure that each roller shared 25% of the total.bundle load and to prevent damage to the tube bundles. Also, specially designed carts were fabricated to allow the replacement waterboxes to be moved into position through the condenser shell using the rigging assembly available in the condenser hotwell.

The fifth challenge was the removal of the existing condenser tube bundles and waterboxes. After an extensive evaluation of all available alternatives, it was decided that the existing condenser tube bundles would be cut in half inside the condenser shell and removed with waterbox attached. However, to move the tube bundle halves with waterbox attached, each bundle would have to be stiffened to allow the bundle to be both rolled out of the condenser shell using the hydraulic rollers and lifted out of the tube pull pit with the gantry crane.

The final challenge was estimating, planning, scheduling and managing the resources and manpower required to complete a construction project of this size with the available refueling outage window.

CONCLUSION

The ANO-1 Condenser Project was successful in all phases of the project including: initial condition assessment, project feasibility study, competitive bid process, condenser re-design, shop fabrication, bundle transportation and field installation. The complete installation of the redesigned condenser tube bundles and waterboxes was accomplished during the Fourteenth Refueling Outage of ANO-1. The duration of the refueling outage was 43 Days and 15 Hours. The Circulating Water Outage required for the condenser replacement was 33 Days and 21 Hours. Although a full ASME PTC 12.2 performance test was not completed following the condenser tube bundle replacement, the condenser backpressure for the redesigned condenser was measured using plant instrumentation and the results indicated an improvement of 0.19 inHg to 0.23 inHg when compared to the backpressure of the original condenser at the same circulating water temperature and condenser duty. To date, the replacement condenser tube bundles have not experienced any in-service tube leaks and unit has been operating reliably and efficiently.

REFERENCES

- Kurtz, S.A., Ward, R.L., Schuunerth, D.J., A Titanium Tubed Modular Condenser Changeout at the Ravenswood Generating Station, PWR — Vol. 12, Performance Monitoring and Replacement of Heat Exchanger Components and Materials, American Society of Mechanical Engineers, 1990.
- Heat Exchange Institute (HEI) Standards for Steam Surface Condensers, Eight Edition - Addendum 1.

EPRI CS-3914 — Biofouling Detection Monitoring Devices — March 1985

- EPRI CS-3844 — Condenser Procurement Guidelines — May 1985.
- EPRI CS-3200 — High Reliability Condenser Study — July 1983.

EPRI NP-2371 — Condenser Retubing Criteria Manual — May 1982.

Table 1
Comparative Performance Requirements and Configuration

	Existing	Required*
Condenser heat load – total Btu/hr.	5.711×10^9	6.150×10^9
Number of condenser shells	2	2
Number of tube bundles per shell	2	2
Number of waterboxes per shell	4	4
Number of tubes per condenser shell	19,608	24,974
Surface area per condenser shell – ft^2	254,000	287,825
Tube material	Admiralty	Titanium
Tube Diameter – in.	1.125	1.00
Tube gauge (condensing section) – BWG	18	24
Tube gauge (peripheral impingement section) –BWG	n/a	22
Design circulating water flow rate – total gpm	764,000	782,200
Average tube circulating water velocity – ft/s	7.52	7.00

(*) Required operating parameters after the contemplated 8-percent power uprating

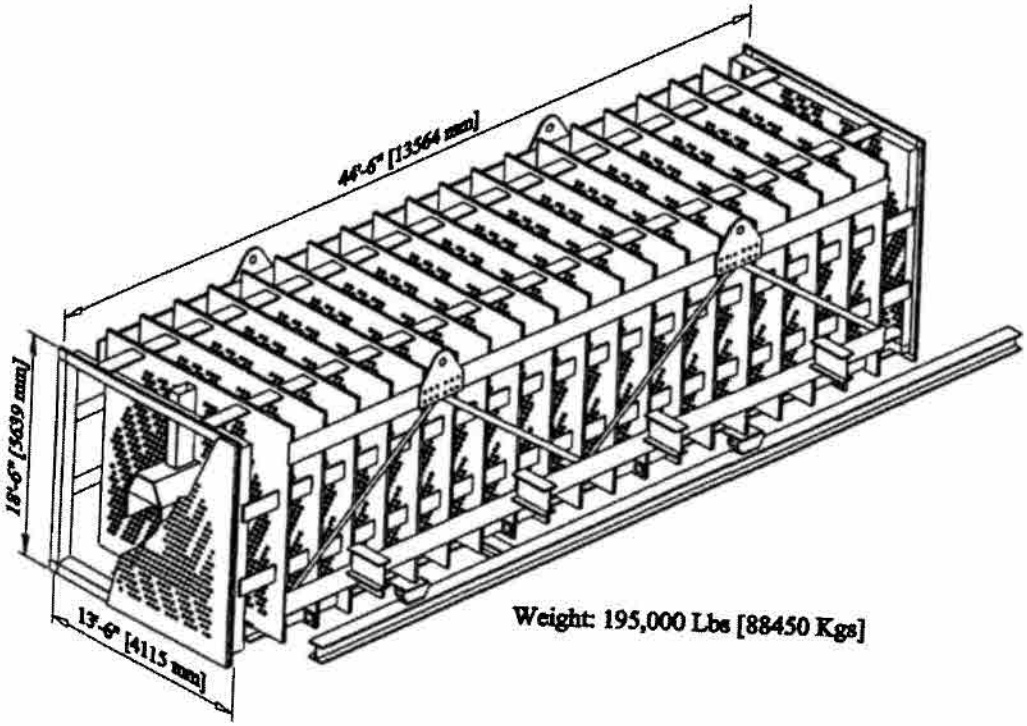

Figure 1
Condenser module arrangement

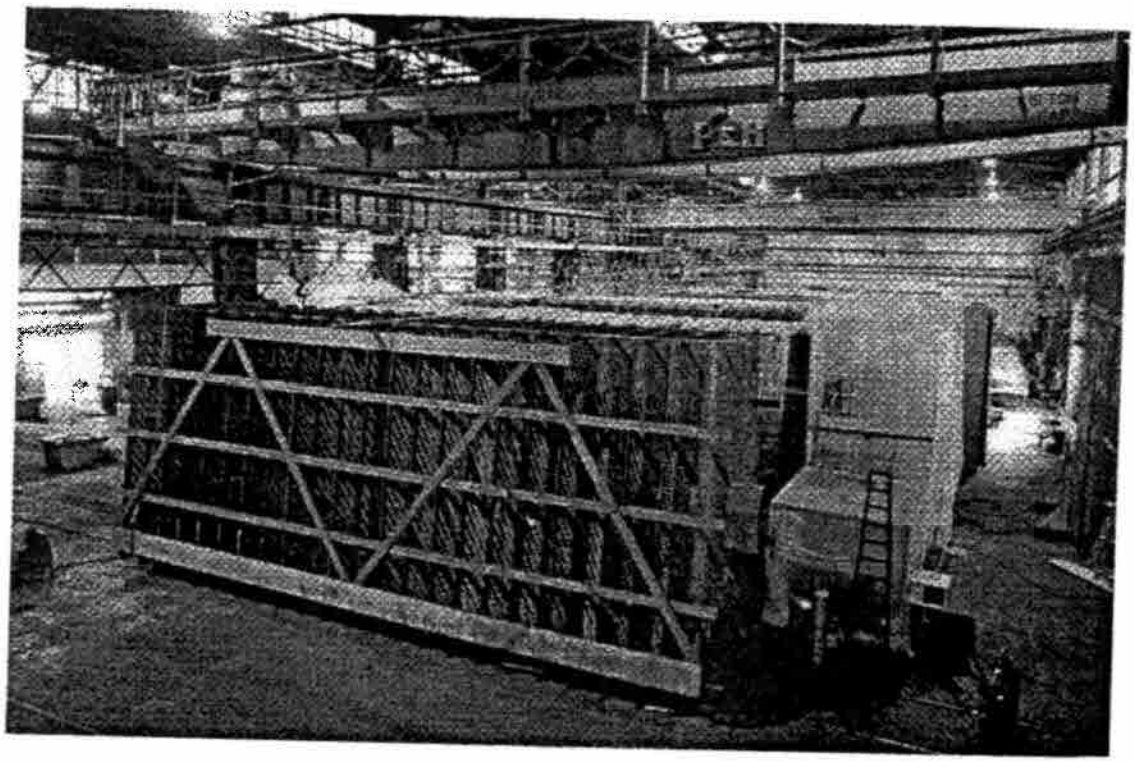

Figure 2
Bundle fabrication and tube welding clean house assembly

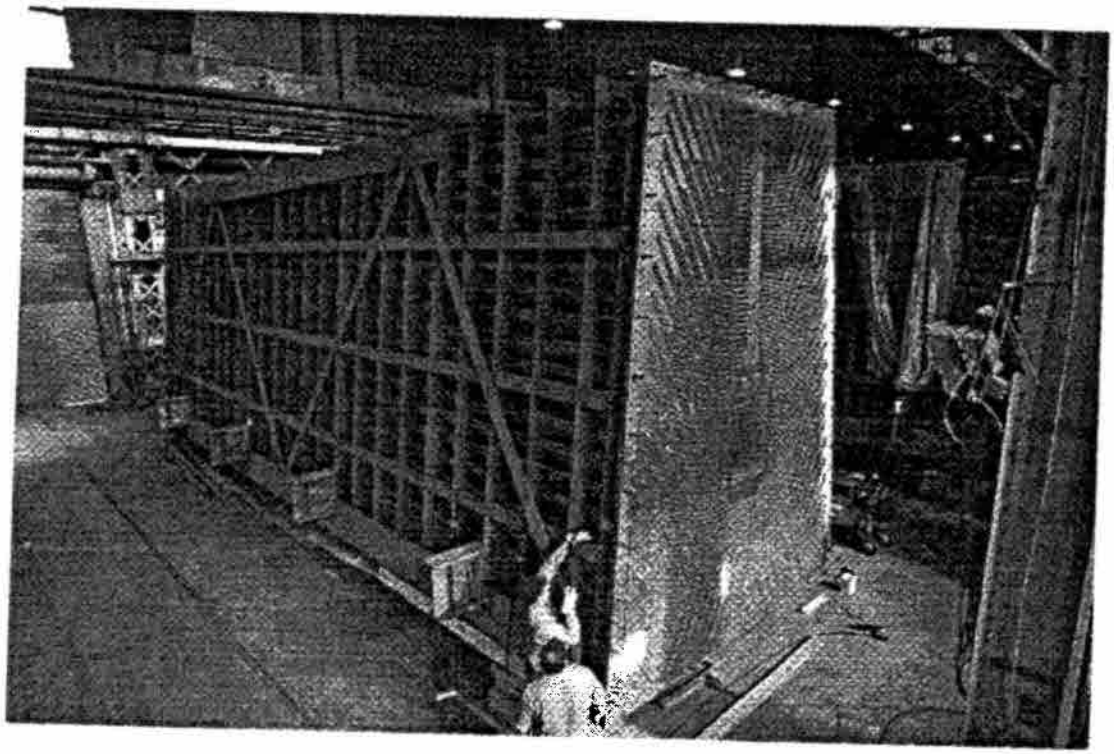

Figure 3
Bundle inspection prior to shipment

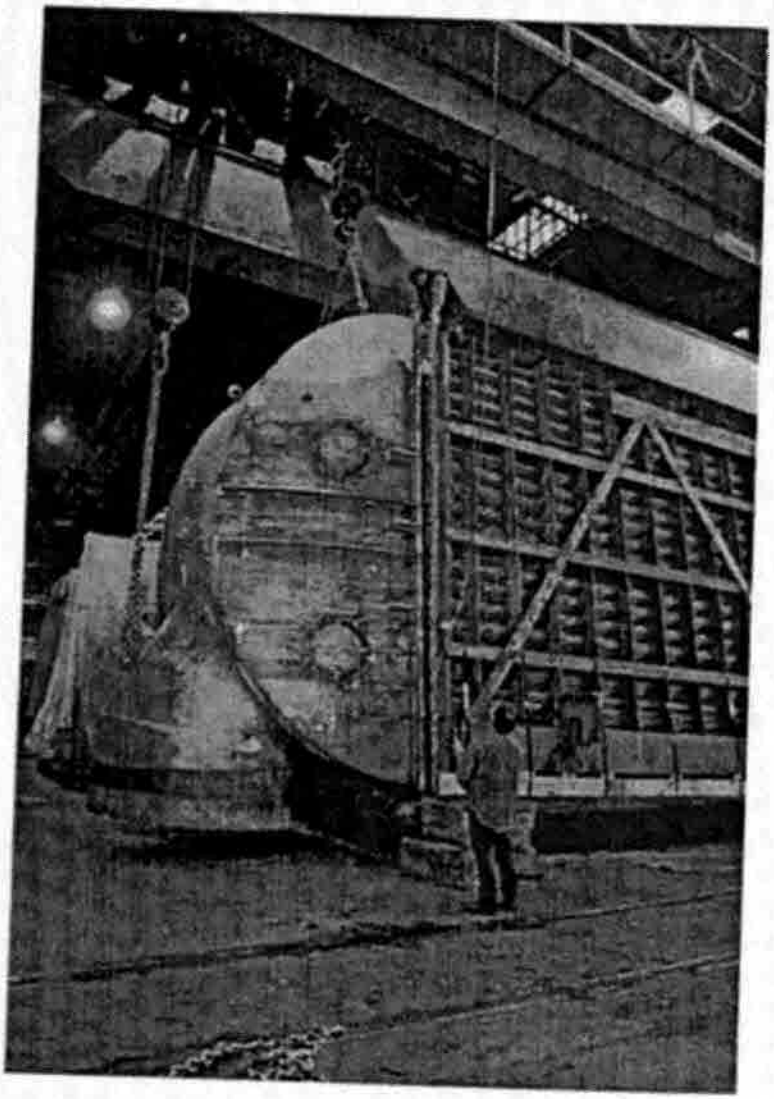

Figure 4
Waterbox fit up in the factory

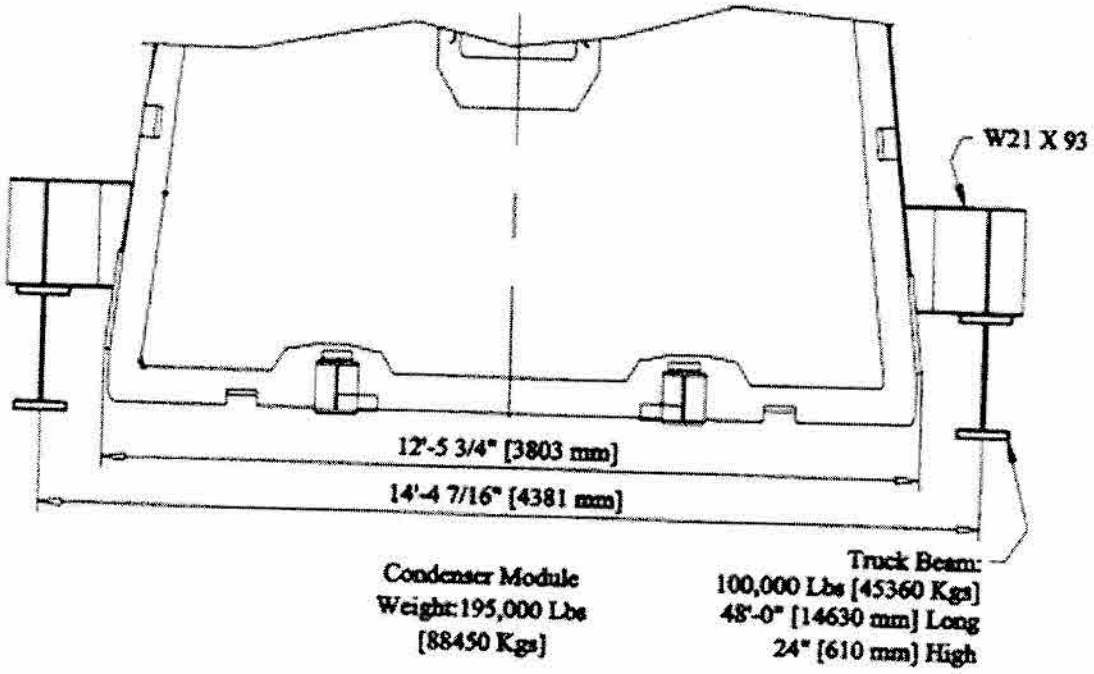

Figure 5
Truck beam arrangement

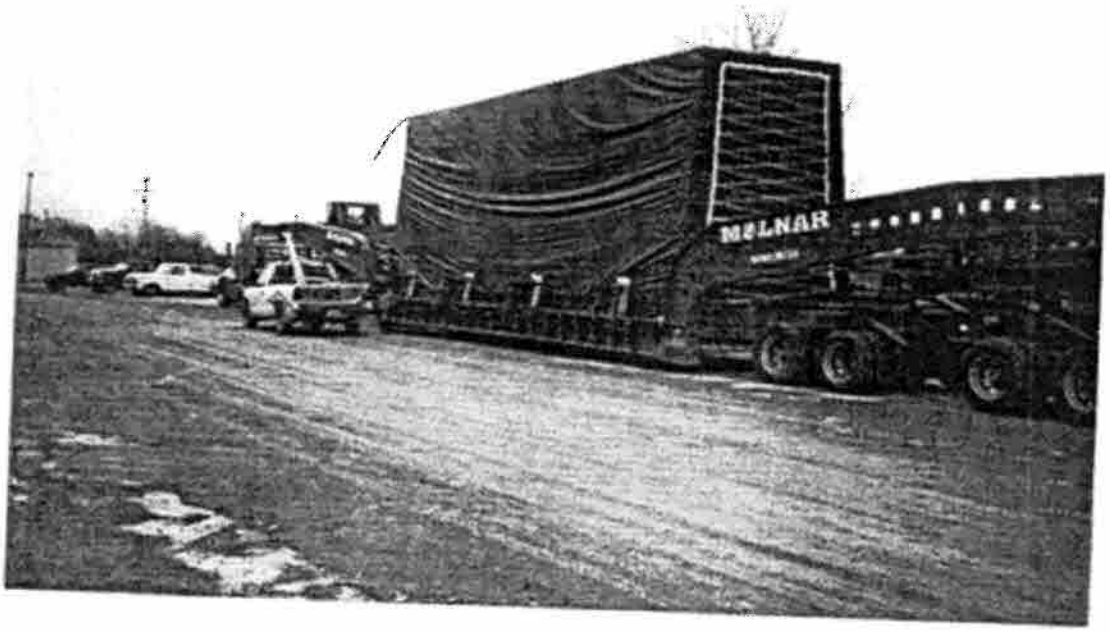

Figure 6
Bundle transportation from factory

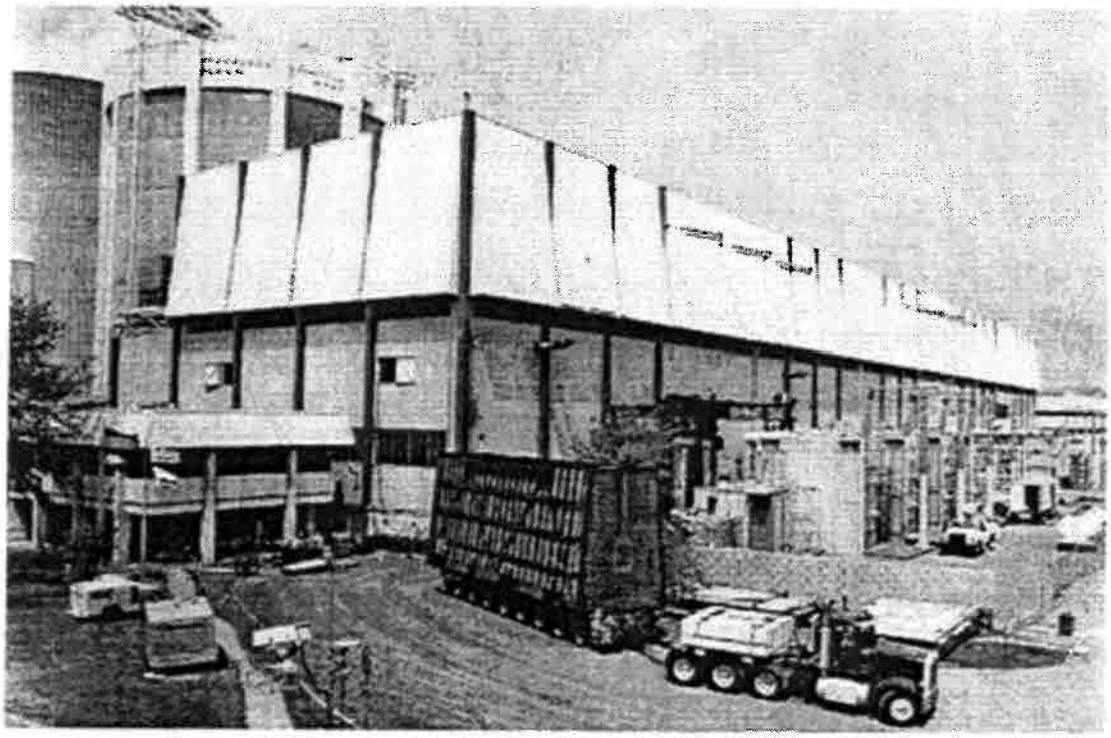

Figure 7
Bundle transportation at the site

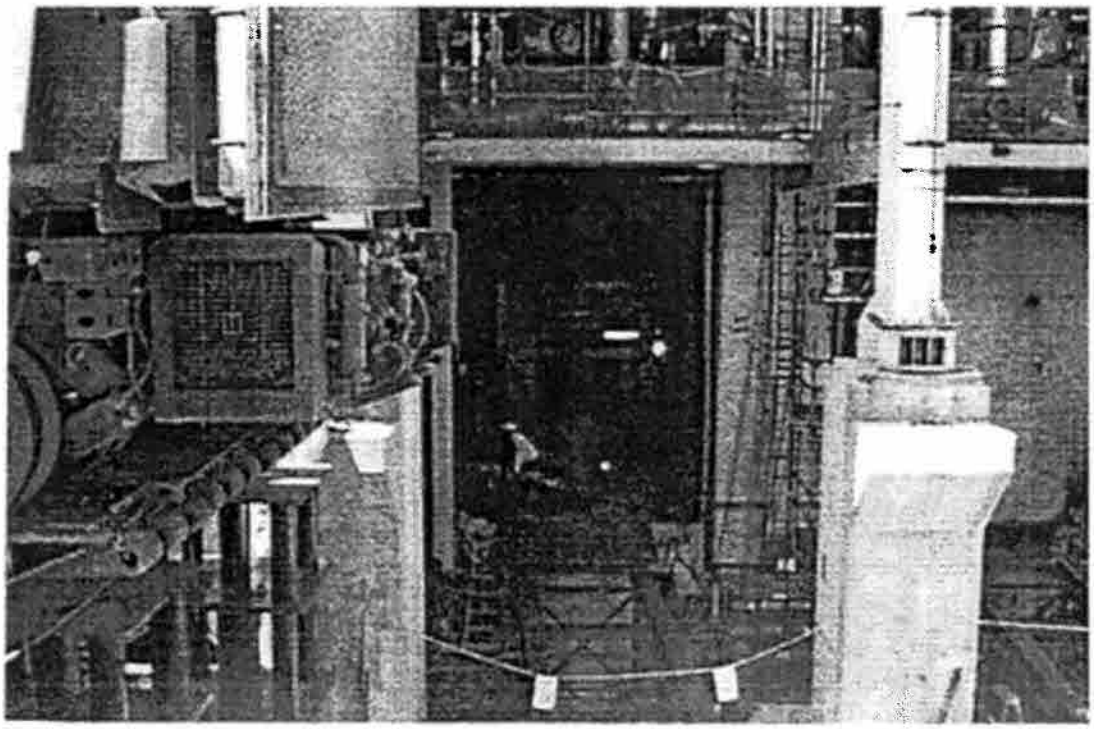

Figure 8
Opening in the turbine building wall

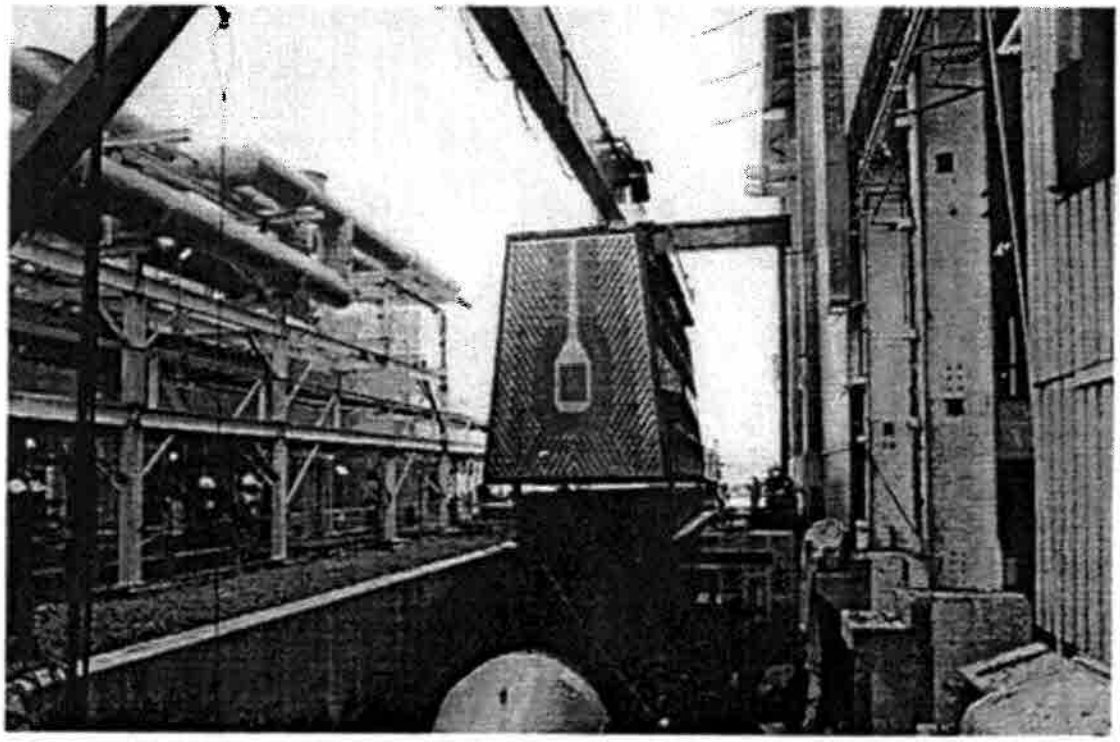

Figure 9
Condenser bundle at ground elevation above the tube pull pit area

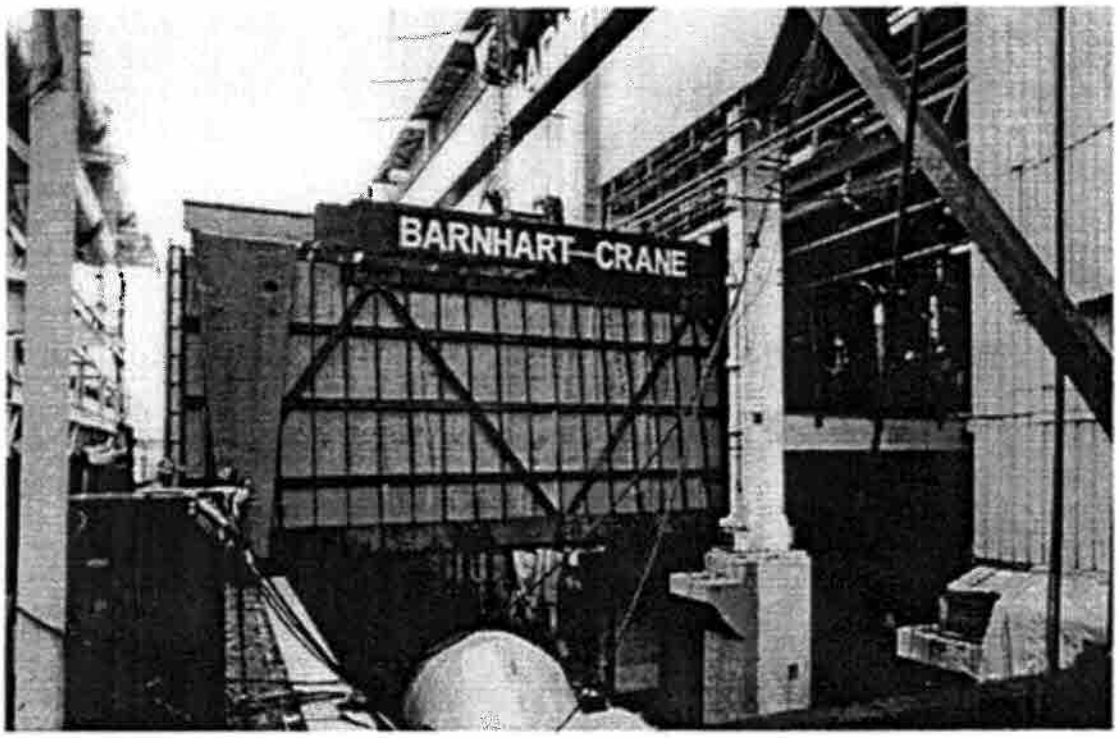

Figure 10
Bundle insertion into the turbine building

CGS Condenser Replacement Update

The tube bundle modules (Modules) and the water boxes on the main condenser will be replaced during the 78 day spring 2011 outage which is scheduled to start on April 6, 2011.

All twelve condenser modules and associated water boxes have arrived on site along with 12 shipments of field weld pieces

Design Work: Engineering designs from B&W (the installation contractor) for module bracing, shell stiffening, rigging/supports have not yet been completed and is impacting completion of the remaining work order planning. The Project team is continuing to work with B&W to expedite completion of this work.

There will be a couple of planned Field Change Requests issued during the outage to document as built condition of several piping runs that must be field run to deal with anticipated interference problems.

Work Orders: Work order preparation met the outage mile stone of having 98% of the work orders planned. The next goal is to complete walk-downs of the tasks on the work orders. This goal will not be met by the January 13, 2011 milestone. The Project team and B&W are working extended hours to complete all of the walk downs as quickly as possible while maintaining quality. The Project is working on a revised walk down completion date to provide to Outage management.

Readiness Review: Ex 6 completed his readiness review and submitted his final report that has been forward to BPA and EN senior management. Ex 6 had three recommendations based on his outage readiness review, of the three recommendations made, only one applied directly to the condenser project. Ex 6 executive summary concludes the condenser replacement project appears to be well managed and is following the recent guidance provided by INPO on nuclear project management.

Cost Estimate: Budget for the current fiscal year (FY11) is currently at $42.2M. This estimate includes changes to temporary access point (TAP) made necessary by security regulations.

B&W has informed the Project of a scope increase/cost impact from the original design (revision 0), that the installation contract was bid on; to the current design (revision 6) supplied by SPX the module designer. The Project team is working with B&W to determine the impact and expect to have an estimate from B&W by the end of January.

Issues:

1. Completing the work order walk downs. The Project is working on a new completion date.

2. The 96" Circulating Water isolation valves contingency repair plan is a project risk that is not yet fully funded. It is expect that two of the six Circulation Water isolation valves for the condenser will require repairs. Parts have been ordered but funding for the contingency work has not yet been identified so a contract can not be awarded for the work.

3. TAP design is done for phase 2 of Site access but completing the installation by the February 28, 2011 goal will be challenging.

4. B&W claims for increase scope from the original revision 0 design.

BPA Perspective: Overall, EN has adequate controls in place to successfully manage this project to completion. This view was confirmed by Ex 6 in his review.

CGS Condenser Replacement Update

The tube bundle modules (Modules) and the water boxes on the main condenser will be replaced during the 78 day spring 2011 outage which is scheduled to start on April 6, 2011.

All twelve condenser modules have arrived on site. Eddy Current testing of the modules identified two tubes needing to be replaced due to damage that occurred either in packing or shipment. Several tubes could not be tested due to interferences at the tube sheet opening that would not allow the Eddy Current probe to be inserted into the tube. Energy Northwest will have the module fabricator correct these problems on site prior to installation.

The water boxes are scheduled to be on site by mid November.

Design Work: Completion of engineering design work has progressed to the point where it is no longer a challenge to the project. There will be a couple of planned Field Change Requests issued during the outage to document as built condition of several piping runs that must be field run to deal with anticipated interference problems.

Work Orders: Work order preparation met the outage mile stone of having 98% of the work orders planned. The next goal is to complete walk-downs of the tasks on the work orders.

Readiness Review: EN is planning to conduct a readiness review of the condenser project on the morning of October 28th. Due to scheduling conflicts, Dave Oatley will unable to attend but PGC staff will participate in the review. We are planning to work with Dave Oately to set up a time in November or early December for him to do an independent review of the project readiness.

Cost Estimate: Budget for the current fiscal year (FY11) is $40.9M. Total project costs (FYs 08 -12) are estimated at $113.4M, an increase of about $6.1M over the original business case done February of 2008. These estimates do not include changes to temporary access point mentioned below that could increase the project costs by $1M.

Issues: Site access, due to the number of craftsmen scheduled to work on the condenser during the outage, the Plant's existing primary security access point would be over loaded and would have difficulty in processing the condenser project personnel, in addition to all the regular outage personnel, into the Plant every morning and each afternoon following their noontime lunch break. The over crowding would cause delays in getting personnel to their work locations inside the protected area, thus impacting the refueling outage costs and length. As a solution to this problem a second, temporary access point was planned; however, the costs of this second access point have increased dramatically as the most recent NRC mandated security rules require the same level of surveillance equipment as the primary access point. Originally the plan was to use extra security personnel to meet these requirements but it has been determined that this approach will not meet the NRC mandated requirements. The Plant staff is preparing an estimate of the costs to meet the NRC requirements and is rerunning the business case to determine if it is still cost effective to use a temporary secondary access point during the outage.

BPA Perspective: Overall EN has adequate controls in place to successfully manage this project to completion. EN is planning to conduct independent readiness reviews along with the installation contractor.

CGS Condenser Replacement Update

The tube bundle modules (Modules) and the water boxes on the main condenser will be replaced during the 78 day spring 2011 outage which is scheduled to start on April 6, 2011.

Four of the twelve Modules are on site; five more are packaged and ready to be shipped. All twelve Modules are expected to be on site by mid August. The Modules were inspected at the fabrication facility prior to being packaged for shipment but after arrival on site each of the Modules will be "Eddy Current" tested for indications of leaks or damage incurred during shipping.

The water boxes are scheduled to be on site by the end of October.

The installation contractor has had key management people on site since January working on their mobilization plan, QA plan, Safety Plan, Rigging Plan, schedule, qualification of their work documents and welding program.

Design Work: Completion of the engineering design work continues to be the biggest challenge to the project. There are 13 heater drain lines that are required to be rerouted as part of the Module replacement. Completion of the design and pipe stress analysis has been running behind schedule. EN has taken corrective actions and the design packages are now expected to be completed by engineering in July.

The Plant staff is considering the formation of an Engineering team that will be available to address field change requests and other design issues that will come up during the actual field installation in the outage. Engineering resources need to be available to support prompt resolution and keep the work going in the field. The ability to stay on schedule and successful completion of the installation will be impacted by the ability to resolve design issues during the outage.

Work Orders: Work order preparation is behind schedule because the engineering design has not been completed as mentioned above. If the engineering designs are completed per the recovery plan, the milestone of having 98% of the work orders planned by October is still achievable.

Readiness Review: EN is planning to conduct a readiness review later this summer or early fall to check the project's status and preparedness to perform during the spring refueling outage. PGC has asked Ex 6 to conduct a readiness review and are having discussions with him regarding participation directly in the EN review process or to review EN's report for completeness and conclusions and then provide his own insights.

Cost Estimate: Budget for the current fiscal year FY11 is $40.9M. Total project costs (FYs 08 - 12) are estimated at $113.4M, an increase of about $6.1M over the original business case done February of 2008.

BPA Perspective: Overall EN has adequate controls in place to successfully manage this project to completion.

Issues: None

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May 9, 2006

Paul E. Norman
Senior Vice-President, Power Business Line
Bonneville Power Administration
c/o Public Affairs Office – DKC - 7
P.O. Box 14428
Portland, OR 97293-4428

Re: Clarification of the Comments of the Western Public Agencies Group On BPA's Power Function Review II Draft Close-out Letter

Dear Mr. Norman:

On April 26, 2006, the Western Public Agencies Group (WPAG) provided comments on your draft close-out letter of April 4th, 2006, for Phase II of the Power Function Review (PFR II). We would like to clarify the remarks contained in section 2 of those comments.

The WPAG utilities have urged BPA to carefully scrutinize all costs that go into its rates, whether they are Corps, Bureau, Energy Northwest or BPA's internal costs. Consistent with that approach, section 2 of the WPAG comments suggested that the budget item for the ENW condenser replacement receive a similar review.

Since the WPAG comments were submitted, we have received additional information on this item from ENW. Based on that information, the WPAG utilities are persuaded that this budget item has been substantiated in the amount and with the timing proposed.

The WPAG utilities felt it was important that you receive this information as promptly as possible. This is an instance where the PFR II process has worked as it should – a question was raised, and a fully responsive answer was timely provided.

(over)

Yours truly,

/S/ Terence L. Mundorf

Terence L. Mundorf
Attorney for the Western Public
Agencies Group

Department of Energy

Bonneville Power Administration
Mail Drop 1399
P.O. Box 968
Richland, Washington 99352-0968

POWER SERVICES

January 23, 2009

In reply refer to: PGC/Richland

Mr. S. K. Gambhir, Vice President
Technical Services
Energy Northwest M/D PE04
P. O. Box 968
Richland, WA 99352-0968

Dear Mr. Gambhir:

In reference to your letter "Energy Northwest Agreement 327447 Main Condenser Replacement Modules," dated January 20, 2009, and received on January 21, 2009, the Bonneville Power Administration does not disapprove the execution of the proposed contract action.

The proposed action would authorize Energy Northwest to execute a contract as a result of RFP 651803, with Yuba Heat transfer in an amount not to exceed $34,660,000 for the design, manufacture and delivery of twelve condenser modules in support of the main condenser replacement project which is planned for execution during the R-20 refueling outage. BPA notes that this non-disapproval superceeds the non-disapproval provided to you in our November 10, 2008 letter.

Sincerely,

Andrew J. Rapacz, Manager
Contract Generating Resources

cc:
Mr. Brian G. Berglin, Energy Northwest - 964F
Ms. Lynne A. Pagel, Energy Northwest - PE10

bcc:
Official File – PGC (PM-14-23) (Columbia)
ERMS: http://bpaweb/services/erms/PM/14/23/PGC%20Records/Forms/AllItems.aspx

Ex 6 :1/23/09 (W:\Office\Briefing Papers\CY 2009 papers\a 1089 Main Condenser Module Fabrication Yuba bb.doc)

BONNEVILLE POWER ADMINISTRATION
CONTRACT GENERATING RESOURCES (PGC)
Briefing Paper, Columbia Generating Station (CGS)
Action Memorandum No. 1089
CGS Main Condenser Replacement Modules

REFERENCES: 1) Energy Northwest letter to A. J. Rapacz, "Energy Northwest Agreement 327447 Main Condenser Replacement Modules," dated January 20, 2009, and received on January 21, 2009. This letter supersedes EN's previous condenser module award letter, Energy Northwest letter to A. J. Rapacz, "Energy Northwest RFP 651803 Main Condenser Replacement Modules," dated October 23, 2008, and received on November 7, 2008.

2) PGC briefing Paper for Energy Northwest letter to A. J. Rapacz, "Energy Northwest Agreement 319873 Contract Release 28 Main Condenser Project Design Support," dated March 24, 2008, and received on April 1, 2008.

3) PGC briefing Paper for Energy Northwest letter to A. J. Rapacz, "Energy Northwest Agreement 326930 Main Condenser Project Design Support," dated August 27, 2008, and received on September 8, 2008.

CONTRACT: Energy Northwest Action Memorandum No. 1089 Columbia Generating Station Main Condenser Replacement Modules to Yuba heat Transfer (Yuba).

ACTION TOPIC: Energy Northwest (EN) has requested BPA's non-disapproval for execution of Action Memorandum 1089 for RFP 651803 Main Condenser Replacement Modules, to Yuba in an amount not to exceed $34,660,000 for design, manufacture and delivery of twelve main condenser modules in support of the Main Condenser Replacement Project. Replacement of the main condenser is planned for execution during the R-20 refueling outage (FY 2011).

DISCUSSION: **Background** - The main condenser is a critical component and is required for operation of CGS. Sustained poor maintenance and inadequate foreign material exclusion control has created a situation of condenser tube failures resulting in unplanned plant down powers for tube leak repairs and additional costs for inspections and tube plugging. EN's technical staff estimates the end of useful life of the current main condenser is 2018. Additional concerns are related to high levels of copper (Admiralty Brass) contained in the current condenser tube material which challenge reliable operation and minimization of radiation dose to employees. Reliable operation of this system is a high priority for EN. The maintenance and repairs performed during the last refueling outage (R-18) have proven effective with no power reductions necessary since the R-18 outage. EN does anticipate however, that new tube leaks will develop at some point in the future. With the extensive tube plugging in R-18, it is hoped that CGS can run until R-19 with minimal leaks. CGS is currently operating with a very small leak resulting in additional resin costs to maintain reactor chemistry. As stated by the EN VP of Technical Services at the March 2008 Board of Directors meeting, the continued operation of the main condenser is not a nuclear safety issue.

Work Scope - The Main Condenser Replacement Project has been broken down into two principal segments based on the two main requests for proposal (RFP): 1) contracts associated with RFP 651803 for design, fabrication and delivery to the site of replacement condenser modules, and 2) contracts associated with RFP 651804 for performance of tasks necessary for the removal of the existing condenser modules and installation of the new replacement condenser modules. The contract that will result from execution of this Action Memorandum is part of a larger overall effort executed as a phased approach to replace the main condenser tubing and supports with pre-fabricated titanium modular bundles. The phased approach is described in more detail in Reference 2. Reference 3 documents the engineering services for condenser performance monitoring instrumentation and is included here for completeness only.

The purpose of this contract is to provide design engineering services, manufacturing and delivery of 12 main condenser replacement modules to be installed during the R-20 refueling outage. Additional requirements are in accordance with Procurement Specification 12502, and the successful bidder is to coordinate work with EN and EN's installation contractor(s) performing the project management, engineering and installation of the condenser modules.

Procurement Process - The competitive negotiation process was used with RFP 651803, which was first issued on May 23, 2008. Responsive proposals were received August 6, 2008, from Westinghouse (Toshiba), Yuba Heat Transfer (Yuba), and Thermal Engineering International (TEI). Following vendor discussions and plant visits with all three companies, a request for Best and Final Offers (BAFO) was issued on September 29, 2008. The BAFOs were received from all three vendors on October 9, 2008. The proposal evaluation included eight technical and two commercial criteria. The eight technical criteria are summarized as follows: response to procurement specifications and work requirements completeness; relevant experience; team composition and qualifications and experience; fabrication capability and capacity; guaranteed performance; consideration of schedule; technical alignment with EN and project ownership; and overall technical adequacy of the proposal including likelihood of meeting the July 7, 2010 delivery date. The two commercial criteria included acceptance of terms and conditions, and cost.

The contract is a fixed price contract having liquidated damages for late module delivery and provisions for performance payment adjustments for increased/decreased condenser performance. The contract costs include a fixed price element and allowances for cost reimbursement elements such as performance bond and transportation costs.

Final Award – Originally a vendor other than Yuba was selected as being the most technically advantageous and representing the lowest cost to EN. However, during negotiations for finalizing the contract, the original vendor could not answer a number of technical questions to EN's satisfaction, including an evaluation of the economic benefit of using smaller diameter tubes to improve the thermal efficiency of the condenser. At this point EN begin discussions with Yuba, the second ranked bidder to confirm they could provide the technical bases and manufacturing capability to meet the design and fabrication requirements to support the condenser replacement project. Yuba's fixed bid of $34,660,000 is comparable with that of the original contract award.

FUNDING: Funding for a portion this contract is included in the approved FY 2009 Budget. The remaining funding will be provided in fiscal years 2010 and 2011 per the EN approved long range plan.

ISSUES: None with this action.

ACTION: BPA agrees replacing the main condenser tubing will improve the system reliability and significantly addresses reliability concerns. PGC staff will prepare a letter of non-disapproval for the awarding of this contract to Yuba, superseding the previous non-disapproval letter.

bcc: Official File – PGC (PM-14-23) (Columbia)
ERMS: http://bpaweb/services/erms/PM/14/23/PGC%20Records/Forms/AllItems.aspx

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Reviewed: _____ BB / date

AJR 1/23/09
AJR / date

BPA list for Condenser replacement success:

- Condenser critical path schedule reduced from the current 87 days
- Replacement itself completed within schedule
- completed within estimated budget
- obtain all expected increase in electrical output (this is what makes the modular replacement a viable option with a positive NPV)
- no more than one condenser leak for the next 5 cycles
- improved off-gas system performance over the existing system
- personnel safety goals for the Project are met (goals to be established)
- No adverse consequences to other systems in the Plant

Department of Energy

Bonneville Power Administration
Mail Drop 1399
P.O. Box 968
Richland, Washington 99352-0968

POWER SERVICES

September 10, 2008

In reply refer to: PGC/Richland

Mr. S. K. Gambhir, Vice President
Technical Services
Energy Northwest M/D PE04
P. O. Box 968
Richland, WA 99352-0968

Dear Mr. Gambhir:

In reference to your letter "Energy Northwest Agreement 326930 Main Condenser Project Design Support," dated August 27, 2008, and received on September 8, 2008, the Bonneville Power Administration does not disapprove the execution of the proposed contract action.

The proposed action would authorize Energy Northwest to execute Contract 326930 with Westinghouse Electric Company LLC, in an amount not to exceed $634,680 for design engineering services in support of the Main Condenser Replacement Project which is planned for execution during the R-20 refueling outage.

Sincerely,

Andrew J. Rapacz, Manager
Contract Generating Resources

cc:
Mr. Brian G. Berglin, Energy Northwest - 964F
Ms. Lynne A. Pagel, Energy Northwest - PE10

bcc:
Official File – PGC (PM-14-23) (Columbia)
ERMS: http://bpaweb/services/erms/PM/14/23/PGC%20Records/Forms/AllItems.aspx

PESmith:dc:5130:09/09/08 (W:\Office\Briefing Papers\CY 2008 papers\a 326930 Main Condenser Design Engineering pes.doc)

Reviewed: PES 9/10/2008
PES / date

BONNEVILLE POWER ADMINISTRATION
CONTRACT GENERATING RESOURCES (PGC)
Briefing Paper, Columbia Generating Station (CGS)
Contract No. 326930
Main Condenser Project Design Support

REFERENCES: 1) Energy Northwest letter to A. J. Rapacz, "Energy Northwest Agreement 326930 Main Condenser Project Design Support," dated August 27, 2008, and received on September 8, 2008.

2) Briefing Paper to Energy Northwest letter to A. J. Rapacz, "Energy Northwest Agreement 319873 Contract Release 28 Main Condenser Project Design Support," dated March 24, 2008, and received on April 1, 2008.

CONTRACT: Energy Northwest Contract 326930 Main Condenser Project Design Support, to Westinghouse Electric Company LLC (WEC).

ACTION TOPIC: Energy Northwest has requested BPA's non-disapproval for execution of Contract 320932 (Contract) Main Condenser Project Design Support, to WEC, in an amount not to exceed $634,680 for design engineering services in support of the Main Condenser Replacement Project. Replacement of the main condenser is planned for execution during the R-20 refueling outage (FY 2011).

DISCUSSION: This Contract is part of a larger overall effort executed as a phased approached to replace the main condenser tubing and supports with pre-fabricated titanium modular bundles, and is described in more detail in Reference 2. The purpose of this Contract is to provide design engineering services for condenser performance monitoring instrumentation to be installed during the R-19 refueling outage (FY 2009). Monitoring the performance of the condenser during the subsequent Cycle 20 will establish a baseline for performance parameters for the existing main condenser. The Cycle 20 performance data will be compared to the performance data gathered during Cycle 21 from the new main condenser to document improvements and verify manufacturer performance data for the warranty. This instrumentation will measure the performance for the remaining life of the plant and provide increased equipment reliability which is a station focus in Energy Northwest's strategic objective. The performance monitoring instrumentation includes condenser pressure monitors, measurement accuracy improvements, CT riser temperature devices, dissolved oxygen sensors, wireless base radio and server, condenser fouling monitors, ultrasonic flow meters and data retrieval software.

WEC was selected to perform this A/E service work based on previous related experience. WEC designed and installed the wireless instrumentation for the 6A and 6B feed water heaters. In addition, the Energy Northwest technical staff has determined that WEC's on-site experience and intimate knowledge of the changes required, gained through their work on the main condenser conceptual study, makes them the contractor best able to meet the established milestones to design, plan, and schedule work for successful completion. The WEC proposal was evaluated by CGS staff and found acceptable and will be awarded as Contract 326930 as sole source and includes the terms of previously negotiated Master Services Agreement, with minor revisions. Work under this Contract will be performed on a time-and-materials basis in accordance with rates determined to be fair and reasonable.

The main condenser is a critical component and is required for operation of CGS. Sustained poor maintenance and inadequate foreign material exclusion control has created a situation of condenser tube failure and resulting unplanned plant down powers for tube leak repairs. Additional concerns related to high levels of copper (Admiralty Brass) contained in the current condenser tube material challenge reliable operation and minimization of radiation dose to employees. Reliable operation of this system is a high priority for Energy Northwest. The maintenance and repairs performed during the last refueling outage R-18 have proven effective with no measurable tube leaks to date. Energy Northwest does

anticipate however, that new tube leaks will develop at some point in the future. With the extensive tube plugging in R-18, it is hoped that CGS can run until R-19 with no leaks or minimal leaks. As stated by the Energy Northwest VP of Technical Services at the March 2008 Board of Directors meeting, the continued operation of the main condenser is not a nuclear safety issue.

FUNDING: Funding for this contract is included in the FY 2009 Budget.

ISSUES: None with this action.

ACTION: BPA agrees installing performance monitoring instrumentation for determining main condenser performance will enhance verification of manufacture performance data and improve the main condenser system reliability for the remaining lifetime of the plant. PGC staff will prepare a letter of non-disapproval.

bcc: Official File – PGC (PM-14-23) (Columbia)
ERMS: http://bpaweb/services/erms/PM/14/23/PGC%20Records/Forms/AllItems.aspx

PESmith:dc:5130:09/09/08 (W:\Office\Briefing Papers\CY 2008 papers\m 326930 Main Condenser Design Engineering pes.doc)

Reviewed: PES 9/10/2008 AJR 9/10/08

PES / date AJR / date

ENERGY NORTHWEST

Sudesh K. Gambhir
Vice President, Technical Services
P.O. Box 968, PE04
Richland, WA 99352-0968
Ph. 509.377.8313 | F. 509.377.2354
sgambhir@energy-northwest.com

August 27, 2008

BPA
SEP 0 8 2008
RICHLAND

Mr. Andrew J. Rapacz, M/D 1399
Manager Contract Generating Resources
Bonneville Power Administration
U.S. Department of Energy
c/o Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

Dear Mr. Rapacz:

Subject: **ENERGY NORTHWEST AGREEMENT 326930**
MAIN CONDENSER PROJECT DESIGN SUPPORT

Energy Northwest intends to execute Contract 326930 with Westinghouse Electric Company LLC in the not-to-exceed amount of $634,680 for design engineering services in support of the Main Condenser Replacement Project. Details of the aforementioned transaction are contained in the attached Findings of Fact.

This contract action is subject to the right of the Administrator, Bonneville Power Administration, to disapprove pursuant to the Project Agreement.

Respectfully,

S.K. Gambhir
Vice President, Technical Services

/kaw

Attachment

INTERNAL DISTRIBUTION:

Mail Drop:

FILE COPY

August 27, 2008

Mr. Andrew J. Rapacz, M/D 1399
Manager Contract Generating Resources
Bonneville Power Administration
U.S. Department of Energy
c/o Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

Dear Mr. Rapacz:

Subject: **ENERGY NORTHWEST AGREEMENT 326930**
MAIN CONDENSER PROJECT DESIGN SUPPORT

Energy Northwest intends to execute Contract 326930 with Westinghouse Electric Company LLC in the not-to-exceed amount of $634,680 for design engineering services in support of the Main Condenser Replacement Project. Details of the aforementioned transaction are contained in the attached Findings of Fact.

This contract action is subject to the right of the Administrator, Bonneville Power Administration, to disapprove pursuant to the Project Agreement.

Respectfully,

S.K. Gambhir
Vice President, Technical Services

/kaw

Attachment

Author: KA Whelan			**For Signature Of:** SK Gambhir		
Section:	C&MS				
For Approval of:	B Berglin				
Approved:					
Date:					

387 R4

FINDINGS OF FACT
CONTRACT 326930
ENGINEERING DESIGN SUPPORT SERVICES
MAIN CONDENSER REPLACEMENT PROJECT

BACKGROUND/SCOPE

Engineering services are required to prepare a Plant Design Package for R19 in support of the Main Condenser Replacement Project, currently scheduled for completion in R20. Specifically, services are required to prepare the Plant Design Package for the condenser performance monitoring instrumentation.

Monitoring the performance of the condenser during Cycle 20 will establish a base line of performance parameters for the existing condenser. This data will be compared to the data during Cycle 21 from the new condenser to document improvements, verify manufacturer performance data and establish a baseline for the warranty. This instrumentation will measure the performance for the remaining life of the plant and provide increased equipment reliability which is a station focus in Energy Northwest's strategic objective.

Westinghouse Electric Company LLC (WEC) was selected to perform this work based on previous related experience, i.e., WEC designed and installed the wireless instrumentation for the 6A & 6B Feed Water Heaters. In addition, the Technical Representative has determined that WEC's on-site experience and intimate knowledge of the changes required (gained through their work on the Main Condenser Conceptual Study) makes them the contractor best able to meet the established milestones to design, plan and schedule work for successful completion.

REQUEST FOR PROPOSAL

WEC provided a proposal for these services in the amount of $634,680. WEC has proposed to perform the work under the terms of a previously negotiated Master Services Agreement.

EVALUATION

The WEC proposal has been evaluated and found to be technically acceptable. This work will be awarded to WEC under Contract 326930 which will include the terms of the previously negotiated Master Services Agreement, with minor revisions. The work under this contract will be performed on a Time-and-Materials basis in accordance with rates determined to be fair and reasonable.

FUNDING STATEMENT

Contract Requisition 652910 in the amount of $634,680.00 was approved by S. K. Gambhir, VP Technical Services, on August 5, 2008.

RECOMMENDATION

Based on the foregoing discussion, award of Contract 326930 to Westinghouse Electric Company LLC in the not-to-exceed amount of $634,680 for design engineering services in support of the Main Condenser Replacement Project is recommended, contingent upon BPA non disapproval and the rights of the Participants Review Board.

APPROVALS

Prepared by: _____
K. A. Whelan, Pr. Contracting Officer

Approved:

_____
G. A. Sponholtz, Purchasing/Contracts Supervisor

_____
Legal Services

_____
L. A. Pagel, Manager, Supply Chain Services

_____
Brian G. Berglin, Condenser Replacement Project Manager

_____
A. E. Mouncer, VP, Corp. Services/General Counsel/CFO

Whelan, Kathleen A.

From: Woodruff, Michael J.
Sent: Monday, August 25, 2008 2:14 PM
To: Whelan, Kathleen A.
Subject: FW: FYI: Delegation of Authority - Lynne Pagel - August 25-28, 2008

From: Duncan, Marcia A.
Sent: Monday, August 18, 2008 2:06 PM
To: Mouncer, Albert E.
Cc: Armatrout, Gregory P.; Bergara, Carole L.; Bradley, Pamela R.; Bresnahan, Richard A.; Chambers, Celene; Duncan, Marcia A.; Lilly, Pattie J.; Lofstrom, Claudia J.; Martin, Sandra J.; Pagel, Lynne A.; Tillman, Janice C.; Banta, Marianne; Barnaby, Jack A.; Boggess, Charles A.; Boyle, Marilyn T.; Butler, Bruce T.; Butler, Ronald L.; Croyle, Timothy W.; Davis, Bonnie L.; Farwell, Philip B.; Freeman Jr, Donald J.; Fritz, Judy A.; Hamilton, Judy E.; Harrington, Matthew L.; Harrington, Thomas R.; Hendel, Brian J.; Hill, Aaron J.; Ho, Louis L.; Holbron, Gregory J.; Holdren, Nathan T.; Huber, Jeffrey F.; Jorge, Gilmar; Kennedy, Michael J.; Khayyat, Bilal A.; Kimble, Luanne; Lloyd, Donald K.; Lloyd, Robert W.; McGaughey, Karen L.; Paetel, Jerry G.; Parrella, Linda M.; Schwartz, Sherri L.; Severance, Scott A.; Shaff, Richard A.; Simon, Brett M.; Sponholtz, Gregory A.; Steichen, Kim R.; Wendland, Janet E.; Whelan, Kathleen A.; Wood, Arthur K.; Woodruff, Michael J.
Subject: FYI: Delegation of Authority - Lynne Pagel - August 25-28, 2008

Lynne Pagel, Supply Chain Manager will be away from Energy Northwest August 25 through 28, 2008 inclusive. Jeff Huber, Supervisor, Traffic & Warehousing will act as Supply Chain Manager during her absence. Mr. Huber will have full authority of the position except that by which policy cannot be delegated.

Should her return be delayed, this delegation will remain in effect until otherwise rescinded.

'Original signed and filed'

Marci Duncan, Administrative Assistant

Smith

ENERGY NORTHWEST

Huron CONSULTING GROUP

Columbia Generating Station Main Condenser Business Case

February 15, 2008

Experience. **Redefined.**™

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Huron Consulting Group
Who We Are

Founded in 2002, Huron has grown to become recognized as a leading consulting firm.

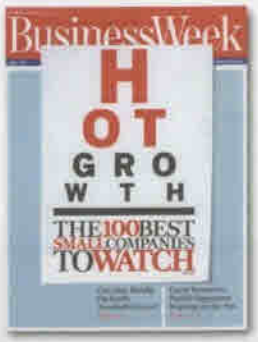
offshoot of Arthur Anderson
HQ Chicago

Background

- Formed in 2002 with approximately 200 professionals.
- Today, over 1,500 professionals with leading experts in numerous industries and critical services including:
  - Strategy/M&A
  - Enterprise Risk Management
  - Operations/Supply Chain
  - Organization Structure
  - Utility Regulation
  - Turnaround/Restructuring
- Headquartered in Chicago with 15 offices in US, EU and Japan.
- Publicly traded since October 2004.
- Conducted more than 2,500 client engagements.

Recognition

- Huron ranked #1 on Entrepreneur's "Hot 100" companies 2 years in a row.
- Huron rated one of the top 10 consulting firms to work for by Consulting Magazine in 2006,
- Huron ranked No. 22 of *BusinessWeek's* top 100 growth companies in 2007.



Huron's Utilities Consulting Group
What We Do

Christin Cabral / Dave Whitten

Huron's utilities consulting group assists clients to define and implement business strategy, improve market share, and lower costs.

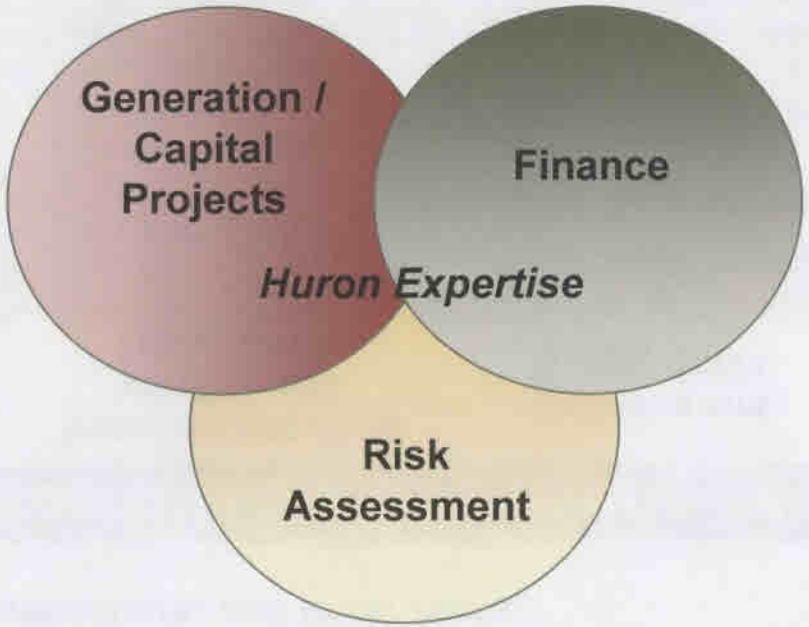
Huron Utilities Consulting Services

Regulatory/Rate Case & Litigation Support	General Consulting and Process Improvement	Sourcing and Supply Chain	Compliance Management
• Regulatory Strategy • Rate Case Support ⇨Financial Evaluation ⇨Strategy & Planning ⇨Expert Testimony ⇨Witness Preparation ⇨Discovery Support ⇨Document Mgmt • Litigation Support ⇨Liability & Damages Testimony ⇨Non-testifying Consulting Support ⇨Discovery & Document Management	• Process Improvement • Capital Resource Optimization • Labor Resource Optimization • Decision Analysis • Risk Assessment • Asset Management Financial Analysis • Cost of Service Assessment/Due Diligence • Strategy and Business Planning • Merger Integration	• Supply Chain Planning • Sourcing • Procurement Transformation & Operational Procurement • Fulfillment • Services Management • Planning & Scheduling	• Audit Preparation & Implementation • Risk Management • Governance & Board Support • Regulatory Compliance • Internal Audit • Management Audits

Who have they done consulting work for?

Mission

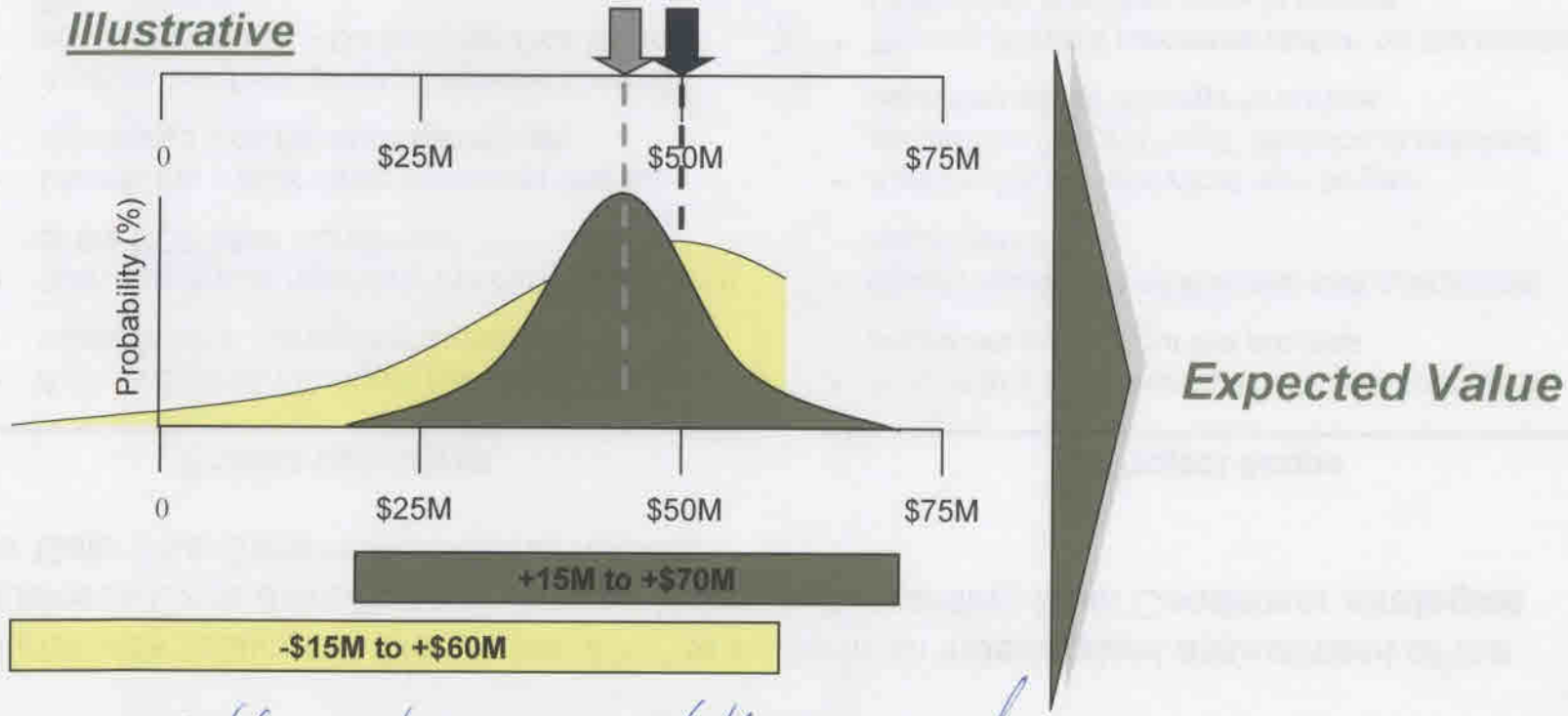
Huron's mission is to assist utility executives and decision-makers with processes, methods, analytical models, and other tools to support strategic and tactical decision-making with respect to capital projects.



We provide an independent assessment without bias and enhance business decision-making by accounting for cost uncertainty and business risk associated with capital projects in an increasingly competitive industry.

Methodology

Our methodology incorporates the use of stochastic techniques, such as Monte Carlo analysis, to aid in analyzing the effect of varying inputs on the output of the model and to understand the full range of results and impacts.



probable values are still assigned by analyst.

Project Objectives and Scope

Huron was retained in December 2007 to perform an independent assessment of the Business Case developed by Energy Northwest regarding Main Condenser strategies for Columbia Generating Station (CGS).

Project Objectives

- Apply a Decision Analysis (DA) methodology to evaluate Main Condenser strategies.
- Gain consensus regarding the current condition of the CGS Main Condenser.
- Identify the critical value measures that are associated with the Main Condenser.
- Analyze the three strategic options currently being considered – Do Nothing, Retube and Replacement.
- Identify the risk and uncertainties associated with each strategic option.
- Validate the quality and the efficacy of the data and assumptions.
- Develop a probabilistic financial model to determine the optimal Main Condenser strategy for CGS.

Project Scope

- Include key CGS management and operations personnel throughout the process.
- Clearly document all financial and operational assumptions.
- Apply sufficient analytical rigor to gain consensus that the "best" decision is reached regarding which strategy to pursue.
- Present Huron's recommendation on the optimal Condenser business case to pursue.

Huron independently analyzed these options.

Huron Project Plan

Week of:

Task	Deliverables	Dec 10	Dec 17	Jan 7	Jan 21	Jan 28	Feb 4	Feb 11
• Understand CGS current state	• Provide interview notes							
• Identify and challenge the assumptions for the condenser business case	• Develop Condenser "Value Map" • Identify minimum and maximum values for each variable • Validate all inputs and assumptions							
• Develop business case	• Develop a Probabilistic Financial Model							
• Validate Financial Model	• Discuss model framework and computations							
• Present findings and conclusions to Project Sponsor	• Conference Call Discussion							
• Present findings and conclusions to Bonneville Power Authority	• Conference Call Discussion							

FME
close
fuel failures

Project Kick-off

Interim Deliverable

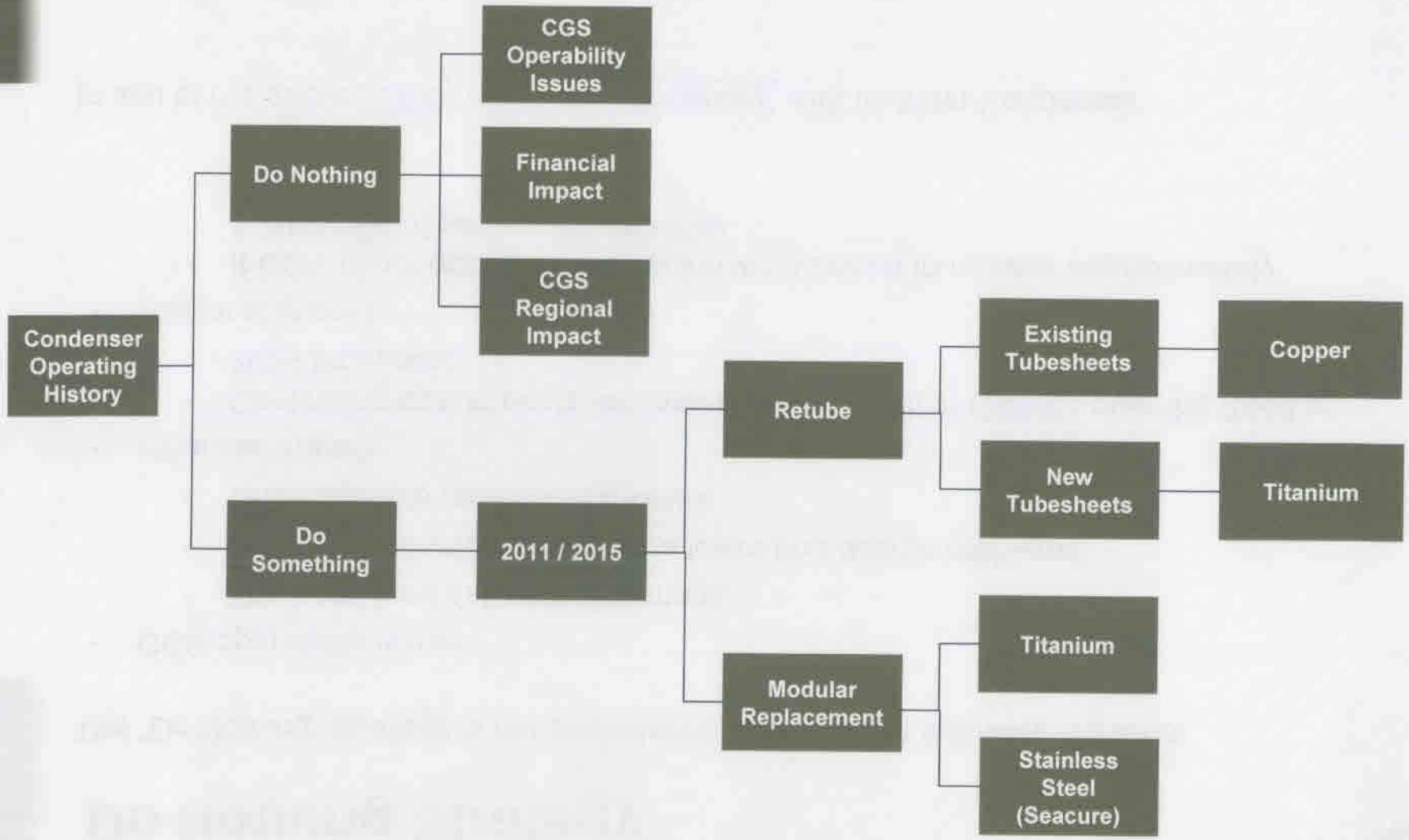
Final Review and Handoff

Issues and Observations

Five major issue areas are impacted by Main Condenser performance.

Issue Areas	Summary Observations
Fuel Integrity	• Copper content in the existing condenser tubes poses a continuing risk of fuel cladding damage and fuel failure events.
Radiation Exposure	• Copper from the condenser contributes to increased plant radiation exposure. • Plant downpower evolutions to repair leaking condenser tubes increase radiation exposure. • Copper from the condenser contributes to additional decontamination activities and increases costs. • Potential future litigation due to radiation exposure to workers.
Operational Reliability	• Recurring condenser tube leaks have impacted plant operation and output by forcing downpower evolutions to repair tube leaks.
Financial Implications	• A result of downpower evolutions, forced outages, increased dose, additional decontamination activities, and lost plant generation CGS costs have been adversely impacted.
Industry Perspective	• The potential for fuel damage resulting from copper corrosion is a high interest issue within the nuclear industry and CGS is lagging the industry in this area.

Condenser Decision Making Strategies



Do Nothing Strategy

The "Do Nothing" strategy is not considered viable for the following reasons:

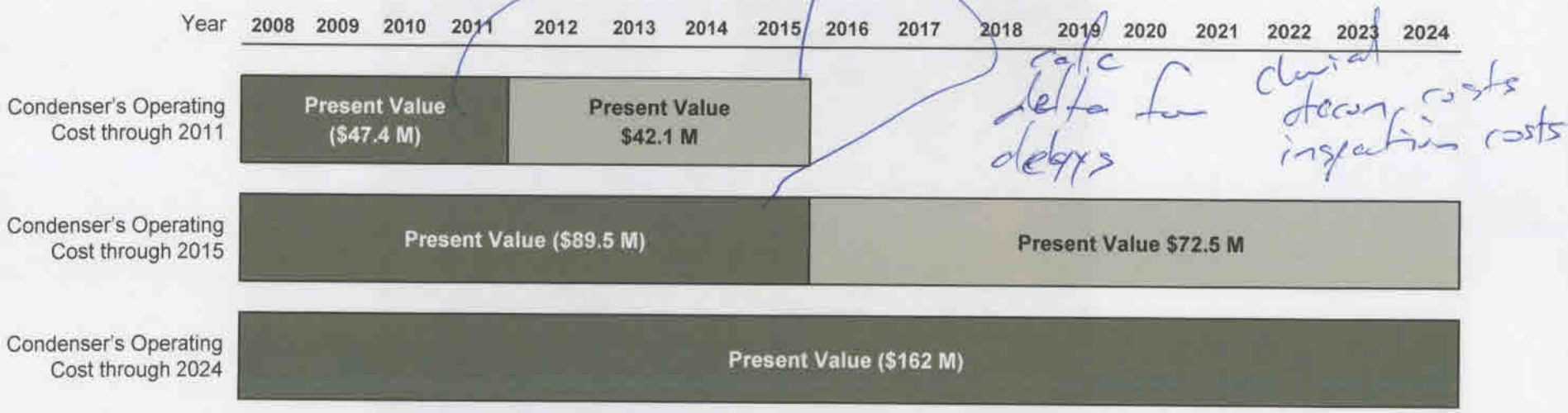
- CGS operability issues:
  - The continued risk of fuel damage.
  - Loss of generation due to tube leaks and design problems.
  - Unacceptable radiation exposure.
- Financial impact
  - Continuing cost impacts estimated at $162 million (2008$) over the 2008 to 2024 timeframe.
- Regional impact
  - If CGS is not operable, the region would need to replace approximately 1,200MWe of generation capacity

In lieu of the above, CGS has to do "something" with its Main Condenser.

When to "Do Something"

8% limit on tubes plugged

Taking into consideration the operating costs of the current condenser, it is financially beneficial to address the current deficiencies in 2011, the earliest available timeframe to "do something."



calc delta for delays

chemical clean costs
steam costs
inspection costs

(units in PV 2008$ millions; values shown are the expected mean values from Huron analysis)

Based upon the analysis performed, Huron calculates an expected present value of approximately $42.1 M in operating cost savings by implementing a Main Condenser strategy in 2011 versus 2015.

+ chemical clean + 3 days outage
+ one DP per year for condenser problems

Main Condenser Strategies Evaluated

Copper Retube Using Existing Tubesheets	Titanium Retube Using New Tubesheets
Stainless Steel (Seacure) Modular Replacement	Titanium Modular Replacement

Strategies Not Considered Viable

Two of the four identified strategies were not considered viable:

- Copper Retube using Existing Tubesheets:
  - Substantial costs associated with the addition of deep bed demineralizers, and;
  - Condenser design issues are not corrected.

- Stainless Steel (Seacure) Modular Replacement
  - Stainless steel tube defects are difficult to detect during the manufacturing process,
  - In-service Non Destructive Evaluation (NDE) methods are inadequate to detect tube cracking,
  - Stainless steel introduces tramp cobalt into the system, increasing radiation;
  - Annual inspection and cleaning costs are significantly higher.

Strategies Considered Viable

Huron performed a detailed financial analysis of the two remaining viable strategic options.

Current Position

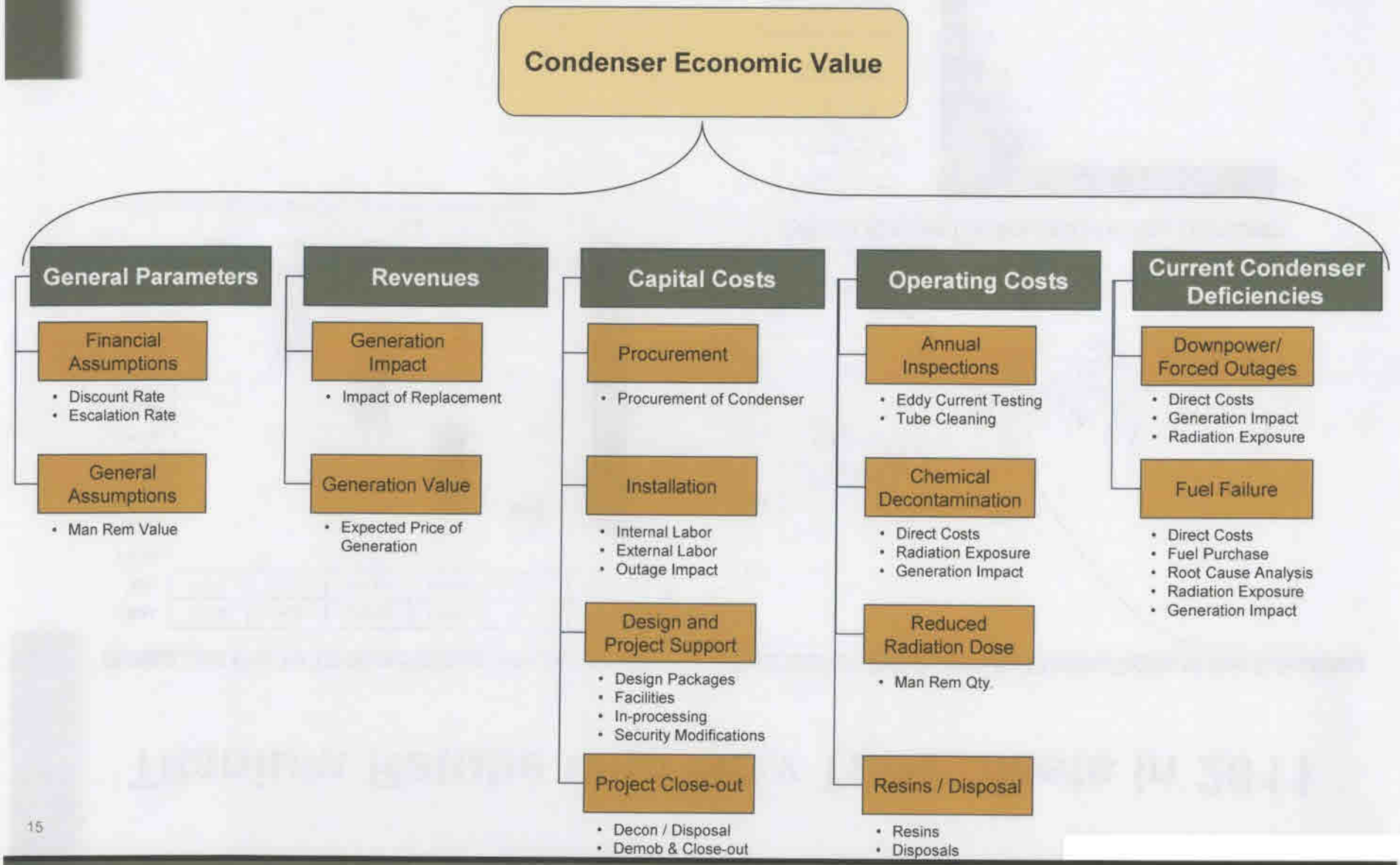
TITANIUM RETUBE WITH NEW TUBESHEETS

- Titanium Retube with New Tubesheets in 2011.
- A total of 1,347 tubes were plugged during the R18 outage bringing the total tubes plugged to 3,384 or 6.96 %.
- Projecting the current condenser tube plugging rate into the future indicates tube plugging will begin to impact condenser efficiency in the year 2015.
  ridiculous high
- However, the Titanium Retube with New Tubesheets strategy in 2011 has financial advantageous over waiting until 2015.
- Potential contamination risks, risk of misalignment and/or scratching or marring the tubes during installation increases outage schedule risks.

MODULAR TITANIUM REPLACEMENT

- Replace the Main Condenser with Modular Titanium design in 2011.
- Modular replacement would include the fabrication of tube modules (sections) with tubes and tubesheets at a manufacturing facility and shipment to the site.
- This method would most likely require rigging and a rail system for removal.
- Potentially less personnel radiation and a lower risk of personnel contamination events as well as less damage to tubes during replacement.
- This option will also result in improved thermal performance through improved condenser design.

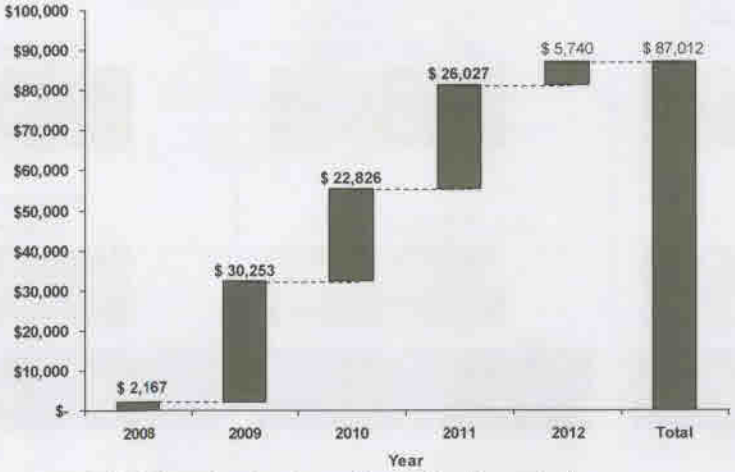
Overview of Condenser Impact



Titanium Retube with New Tubesheets in 2011

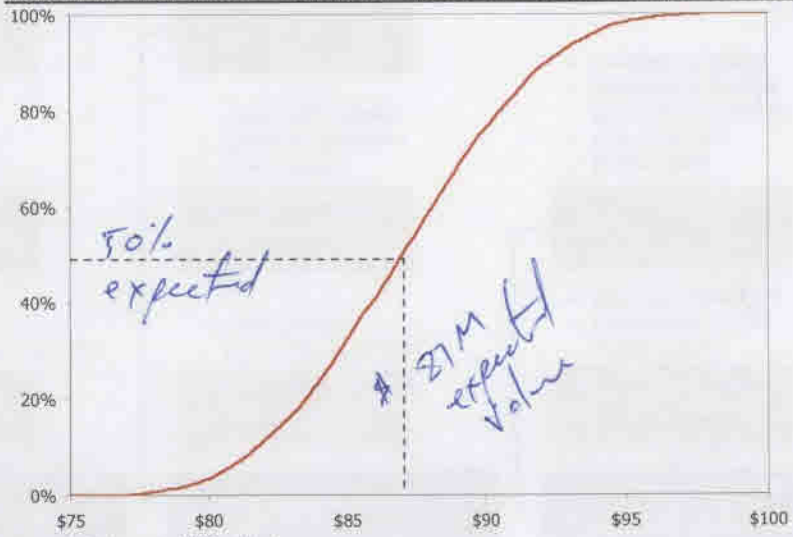
Nominal Cash Flow for Titanium Retube w/ New Tubesheets

	2008	2009	2010	2011	2012	Total
Max	$ 2,559	$ 34,974	$ 27,529	$ 28,411	$ 7,453	$ 98,827
Min	$ 1,795	$ 25,570	$ 18,420	$ 23,590	$ 4,413	$ 75,516



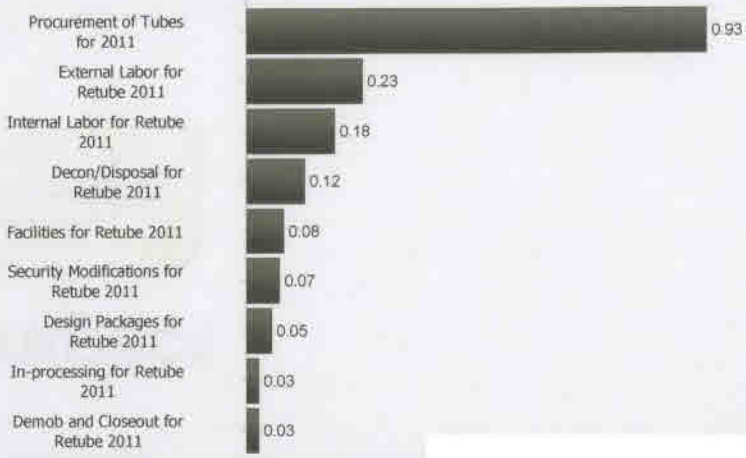
(units in nominal USD thousands; values shown are the mean from Huron analysis)

Total Nominal Cost S-Curve for Titanium Retube w/ New Tubesheets



(units in nominal USD millions)

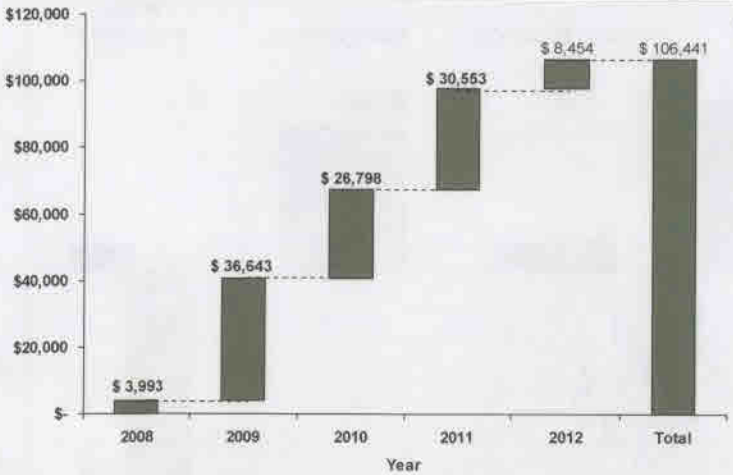
Tornado Chart for Titanium Retube w/ New Tubesheets



Titanium Modular Replacement in 2011

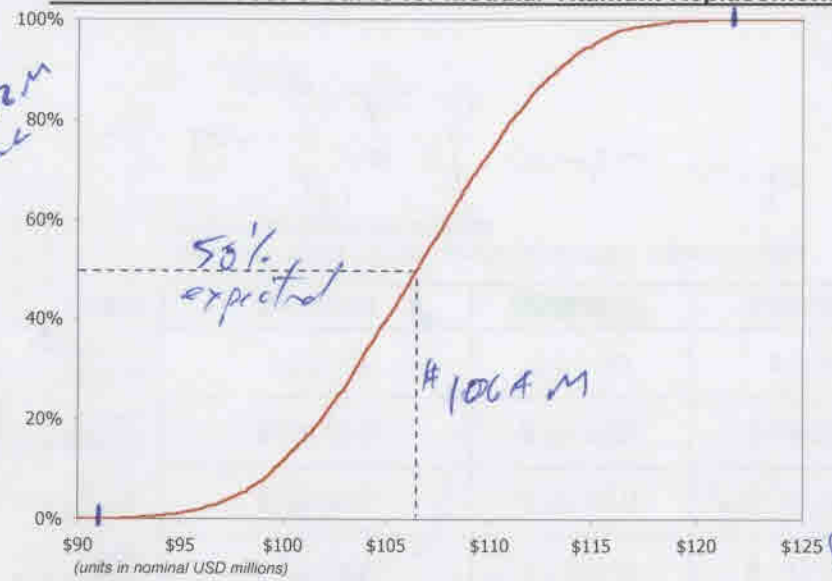
Nominal Cash Flow for Modular Titanium Replacement

	2008	2009	2010	2011	2012	Total
Max	$ 4,769	$ 42,680	$ 31,819	$ 35,260	$ 10,827	$ 122,032
Min	$ 3,212	$ 30,795	$ 21,847	$ 25,685	$ 6,410	$ 91,171

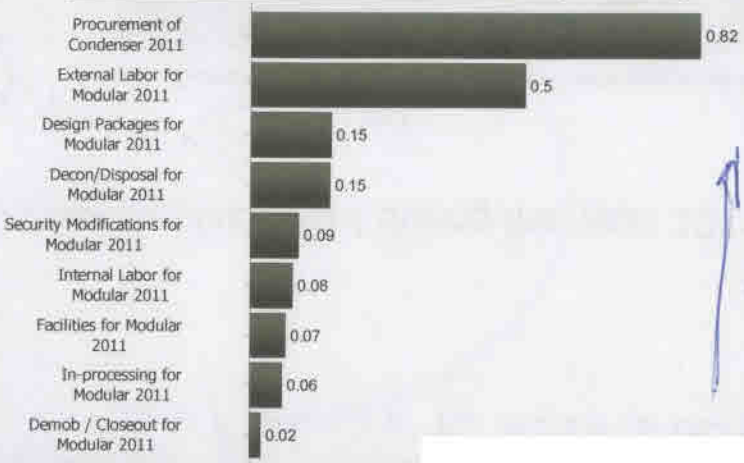


(units in nominal USD thousands; values shown are the mean from Huron analysis)

Total Nominal Cost S-Curve for Modular Titanium Replacement



Tornado Chart for Modular Titanium Replacement



priority focus for increasing proj cost

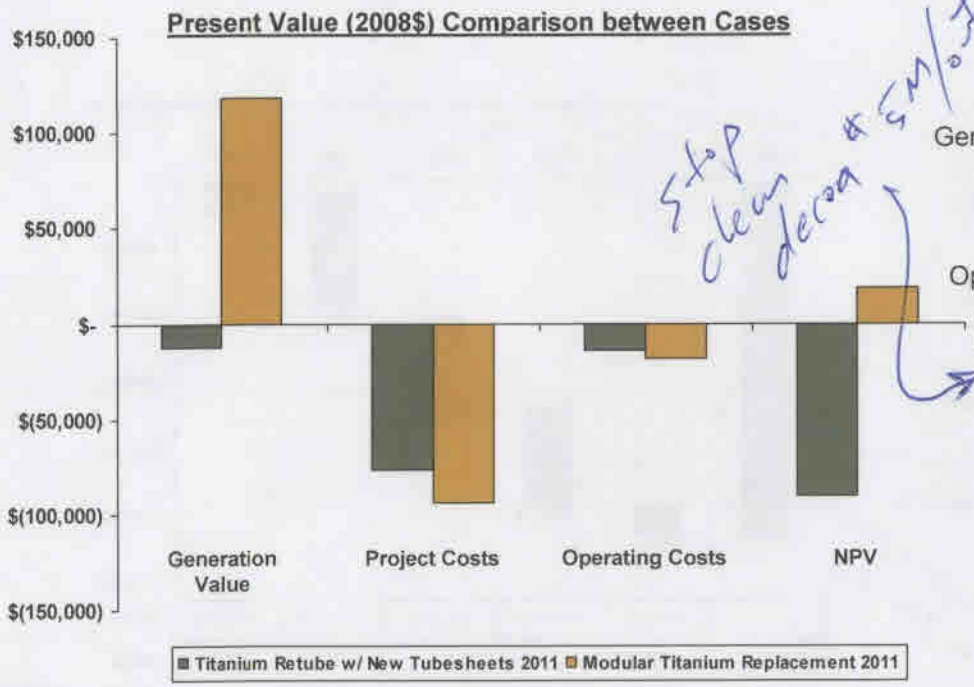
cost impact factor

diff risk due to misalign of tube sheets and inability to seal tubes to tube sheets

Best Viable Scenario

CGS should perform a Modular Titanium Condenser Replacement during the year 2011 outage.

$18M more to do mod Ti



Thru 2044

Comparison of Present Values between both Cases

	Titanium Retube w/ New Tubesheets 2011	Modular Titanium 2011	Delta between cases
Generation Value	$ (12,800)	$ 118,300	$ 131,100
Project Costs	$ (76,706)	$ (93,891)	$ (17,185)
Operating Costs	$ (14,201)	$ (18,900)	$ (4,699)
RFW & RWCU	$ 12,993	$ 13,143	$ 150
NPV	**$ (90,714)**	**$ 18,652**	**$ 109,366**

(units in PV 2008$ USD thousands; values shown are the expected mean values from Huron analysis)

stop clean decon & EM/o fog

no benefit of carbon cost avoidance.

The same outage length is assumed for both cases, although it is possible that the Titanium Retube with New Tubesheets option has an greater risk of longer outage duration due to in-place construction of the new condenser. This requires the perfect "as-building" of >40,000 tube holes.

74 days condenser window

Conclusions

- Technical, economic, and regional impact factors drive the need to replace the Main Condenser by 2015.
- The Main Condenser has a direct and significant bearing upon the operability of CGS.
  - Based upon analysis performed on the current condenser, reliable operation after 2015 is uncertain.
  - If the issue is not addressed in a timely manner, the region will need to replace approximately 1,200 MWe of CGS generation capacity with some other resource.
- Pursuing a Main Condenser strategy in 2011 is financially more advantageous than doing so in 2015.
- There are two viable strategies for condenser replacement:
  - Titanium Retube with New Tubesheets
  - Modular Titanium Replacement
- Several technical and operational benefits favor Modular Titanium Replacement over the Titanium Retube with New Tubesheets.
- On a Net Present Value (NPV) basis, the value of the Modular Titanium strategy in 2011 is approximately $109 million more favorable than the Titanium Retube with New Tubesheets strategy in 2011.
- On a stand-alone basis the Modular Titanium strategy results an NPV of $18.7 million.
- The best technical alternative is also the best financial alternative.

Columbia Generating Station
Main Condenser
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This document summarizes longstanding performance issues related to the design and operation of the Main Condenser at Columbia Generating Station and solutions to those challenges.

The following categories summarize the issues in introductory level detail:

1. System Components Overview
2. Condenser Leakage
3. Columbia's Condenser
4. Columbia Historical Actions
5. Can Columbia Eliminate Condenser Leakage by Eliminating Debris?
6. Industry Data and Experience
7. Solutions

Section 1: System Components Overview

The Purpose of the Main Condenser

The main condenser is a key component in the closed-loop system that transfers energy from the reactor to the turbine, in support of creating electricity. The condenser's primary function is to take steam exhaust from the main turbine and return it to a liquid form. The liquid, called condensate, is highly purified water. The condensate is preheated and pumped back to the reactor pressure vessel where energy in the form of heat is added to convert the condensate back into steam.

See Figure 1 for a simplified diagram (page 9)

Condenser Configuration

The Columbia condenser has three main sections:

1) The steam space, into which the turbine exhaust and other steam sources discharge.
2) The cooling section, where steam passes over brass water pipes filled with cold circulating water, causing the steam to condense back into water (condensate).
3) The circulating water interface consisting of waterboxes, tubesheets, and thousands of tubes. Chemically treated Columbia River water is circulated through special brass tubes, removing heat and transferring it to the Cooling Towers.

Cooling Towers

The cooling towers provide a water source for the circulating water system and transfer heat to the environment. Evaporative losses are replaced with water from the Columbia

River. By nature, the cooling towers act to concentrate debris and impurities. Acid and other chemicals are added to reduce secondary system fouling and corrosion.

It is paramount to prevent the chemical additives and raw water/organic materials from degrading reactor coolant quality.

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Section 2: Condenser Leakage

What Happens During a Small Condenser Tube Leak?

Due to pressure differences, small amounts of chemically treated raw cooling water (circulating water) are transferred to the pure reactor grade water in the condensate system. This water is then run through filters, removing some of the introduced impurities. Impurities that get through the filters then go to the reactor vessel, where they begin concentrating. The concentration takes place as the pure water boils into steam and the impurities are left behind.

As condenser leakage increases, the filters become less and less effective at removing the impurities.

Limitations to the Columbia Design

Some Boiling Water Reactors (BWRs) were designed with, or subsequently added, additional filters in their condensate systems. Called deep bed demineralizers, they are located between the filters like those at Columbia and the reactor pressure vessel. The deep bed demineralizers enhance filtration and water quality prior to entering the reactor. They allow continued safe operation with much greater condenser leakage than is possible with Columbia's design. Additionally, the filters are effective at removing copper, which will be discussed later.

Results of a Small Condenser Leak

Even a small condenser leak has negative consequences for Columbia, including:

- Filters must be changed more frequently to keep the water as pure as possible. Changing filters twice as often (frequently required) increases the cost of the filter media (resin) and the associated disposal cost (radioactive waste that needs to be buried). Each of these operations and disposal maneuvers also impact labor costs and employee dose (radiation exposure).

- Once a leak is large enough to locate, the plant is reduced to approximately 60% power to pinpoint and repair the leakage. Pinpointing and repairing leakage from multiple, small locations, is especially difficult. Each repair entails unplanned generation losses, employee exposure, personnel safety hazards, and increased labor costs.

See Figures 2A-B (pages 10-11)

- Water quality (chemistry) within the reactor degrades. This can:
  1) Result in unplanned power reductions or mandatory shutdowns due to exceeding chemistry limits.
  2) Increase activation of impurities, which increases radioactive contamination and exposure throughout the plant.
  3) Increase the susceptibility of the reactor vessel and internals to cracking, increasing the likelihood for costly repairs.
  4) Disturb the corrosion layer on the fuel and reactor internals. Impacting the fuel corrosion layer can lead to fuel damage. Fuel damage can result in plant de-rate, unplanned refueling outages, increased dose rates and employee exposure, and increased stack release rates to the environment.

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Section 3: Columbia's Condenser

Admiralty Brass Material

Columbia's condenser tubes, like many original condensers, were fabricated from admiralty brass. Admiralty brass is made primarily of copper, with the second largest constituent being nickel. It was selected for its excellent heat transfer efficiency and inexpensive cost relative to other suitable materials.

Susceptibility to Mechanical Wear

Admiralty brass is more susceptible to damage than the other contemporary condenser materials like stainless steel and titanium. For example, plastic tie wraps have caused leaks in our condenser when they became lodged at the inlet end of condenser tubes and, moved by water flow, wore holes in the soft metal tubes. Titanium is approximately 6.5 times harder and stainless steel is about 3 times harder, making them less susceptible to debris induced damage.

Likewise, steam leakage from exhaust lines into the condenser has been known to wear through tubes, leading to rapid increases in condenser leakage and prompt shutdown of the plant to protect primary system chemistry.

Copper and Fuel

Even slow wear of the soft condenser tube material adds copper to the condensate. Columbia demineralizers are not designed for mechanical filtration, the best method for removal of copper. Based on that and the lack of deep bed demineralizers, Columbia is classified as a 'high copper plant'.

Copper's substantial negative impacts on Reactor fuel integrity were identified in the early days of Boiling Water Reactors. A phenomena, known as Crud Induced Localized Corrosion (CILC), is caused by copper entering the reactor, attaching itself to the fuel corrosion layer, and causing localized corrosion and high temperature areas on the fuel cladding. The eventual outcome is often loss of clad integrity and long axial splits of the

clad. That allows fission products to spread throughout the plant and ultimately cause increased release rates to the environment. CILC has rendered large quantities of fuel unusable, costing tens of millions of dollars and extended reduced power operation at some units.

See Figure 3 (page 12)

The industry has substantially lessened, but not eliminated, CILC failures by removing copper from their condenser materials or adding deep bed demineralizers. Columbia has done neither, leaving us susceptible to CILC fuel failures. Columbia has carefully selected fuel cladding to minimize the risk of CILC failure. However, the only real way to rule this failure mechanism out is to remove the source of copper completely.

In addition to fuel impacts, copper is also implicated in the trapping of cobalt in the corrosion layers on all reactor internals. This increases overall plant radiation levels and dose to our employees.

Early Condenser Damage

Poor chemistry control in the early years of Columbia's operations caused corrosion of the condenser tubes. One result is a phenomena, called dezincification, which caused pits in the condenser tube metal. The pits remain and provide initiation sites for localized corrosion and subsequent tube leaks/failures. Based on this, Columbia cleans and "eddy current tests" one-third of our condenser system per outage. With our transition to two-year cycles, Columbia needs to start conducting eddy current tests of all the condenser tubes each outage, starting with R18 in 2007. The $700k per outage testing cost could be substantially reduced with improved condenser material condition.

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Section 4: Columbia Historical Actions

Columbia management conducted a condenser replacement study in 1996. No action was taken on the study results based on unfavorable payback expectations and extended outage time for condenser tube replacement. A key factor at the time was the uncertainty of plant license extension.

Our concerns resurfaced in 1999 following fuel failures at the River Bend plant (admiralty brass condenser with deep bed demineralizers). We closely tracked the River Bend cause analysis. River Bend fuel corrosion had high copper levels, but the failures were attributed to high iron levels in their corrosion layer. Based on Columbia being a low iron plant, no action was taken.

See Figure 4 (page 13)

During 2001, Columbia found that some of its fuel had thicker than expected oxide layers. A root cause team, with industry expertise, studied the previous operating cycle

and fuel scrapings. The fuel had higher than normal levels of copper and iron deposits. Concerns over probable fuel damage were high. Spallation (similar to concrete spallation where material falls off) was identified on Columbia fuel.

See Figure 5A, B, C (pages 14-16)

The root cause was determined to be poor demineralizer performance, coinciding with a chemical intrusion due to condenser system leakage. Had the condenser not leaked this challenge to the fuel would not have occurred.

In 2003, another copper reduction study was initiated that included consideration for deep bed demineralizers or removal of the admiralty brass. The recommended solution was not completed due to external cost pressures.

Columbia's management has thoroughly reviewed options for managing ongoing condenser challenges. On each occasion, continued operating risks were accepted instead of taking action, primarily to avoid costs and extended outage length.

In addition to these studies:

- Columbia has increased the size of our demineralizers to improve filtering efficiency.
- Determined the suction screen on the circulating water system was not properly seated, allowing some debris to pass. Columbia has corrected this and implemented a long-term fix.
- Columbia rebuilt three cooling towers, upgrading the plastic fill and lattice, while removing all plastic tie wraps at $2M per tower. Three towers remain original.
- Columbia has improved our foreign material controls to reduce debris getting into circulating water and subsequently the main condenser.
- Columbia has improved waterbox drainage to allow faster and more complete draining for repairs.
- Columbia staff is looking at screen options in the upcoming outage to further reduce debris entry into the main condenser.

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Section 5: Can Columbia Eliminate Condenser Leakage by Eliminating Debris?

In any raw water system, debris elimination is a challenge that plant designers are faced with. Columbia is blessed with a relatively clean water source in the Columbia River. The Tower Make-up System takes water from the middle of the river through screens. Columbia also has screens at the intake to the Circulating Water Pump Pits. These screens are designed to be small enough to prevent plastic tie wraps and larger debris from passing. Despite this, items pass through the screens or are in the system from

historical operation. Additionally, the screens must be manually raised for cleaning with the plant in operation which allows debris entry.

Cooling towers, due to their design purpose of transferring heat to the environment, are open and susceptible to items being blown in, dropped in from animals, and dropped in during work under adverse conditions. Additionally, the extreme weather variations, water flows, chemical additives, and ice build-up cause corrosion and damage that create debris. Any raw water screen system can reduce debris intrusion, but none appear to be 100% effective.

See Figures 6A-D (pages 17-20)

Finally, in 2003, INPO shared a Significant Experience Report on debris intrusion. The document shares operating experience with screens becoming plugged and causing loss of pump suction. This is an issue Columbia has experienced from algae build-up on plant restarts. Reduction in screen opening size increases the likelihood of plugging.

In May of 2004, a root cause analysis was performed to prevent debris related condenser leaks. Remaining actions from that study are planned for implementation in the upcoming outage. Columbia's actions to date have reduced the quantity of debris in the condenser, and should improve more with an improved screen system. However, debris intrusion will always be an issue to some extent.

It should be noted that the root cause 'does not address tube leaks caused by steam impingement or long term flow induced erosion or other service related tube damage such as dezincification and stress corrosion cracking'. These failure modes were specifically excluded for the purpose of focusing on debris-related leaks, which caused the condenser leak triggering the root cause analysis.

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Section 6: Relevant Industry Data

Current Main Condenser Material
Of the 34 US BWRs:
16 have stainless steel condensers.
10 have titanium condensers.
4 have a combination of admiralty brass with stainless steel or titanium. These sites use the less damage-susceptible materials in the highest risk areas.
Only 4 have admiralty brass condensers, including Columbia.

Our data shows at least 13 of the BWRs have re-tubed their condensers. Nearly all had admiralty brass and went to a different material. Most occurred in the 1980's and 1990's.

See Figure 7 (pages 21-22)

Current Plants with Deep Bed Demineralizers
Of the 34 US BWRs, 20 utilize deep bed demineralizers.

Of the 8 US BWRs containing some admiralty brass in their condenser, only two operate without deep bed demineralizers to address copper. They are Columbia and Vermont Yankee. Vermont Yankee went commercial in 1972. It is a small 593 MWe BWR recently bought by Entergy.

Two of the US BWRs with a combination of admiralty brass condensers and deep bed demineralizers are Limerick Units 1 and 2. Following major CILC related fuel damage on Unit 1, Limerick added deep bed demineralizers. This option was selected over re-tube because it was factored into the original design, with available space in their Turbine Building.

From this section, the case for change, based on copper alone, is strong. We are one of only two operating BWRs that have admiralty brass condensers without deep bed demineralizers. The other BWR, Vermont Yankee, contains 8% stainless steel tubes.

Utilities invested in their facilities to reduce risk. At this point we do not know if their investments passed a business case payback analysis or if action was taken to eliminate the large downside risk, regardless of payback.

Political Landscape
Over the past several years, top focus areas of Chief Nuclear Officers have been Security, Fuel Reliability, and Materials Degradation. In the area of materials degradation, the industry established a program called BWR Vessel Internals Protection (BWRVIP) in 1994 so we could self-regulate, rather than cause the NRC to regulate us. The program provides research, inspection requirements, program requirements and independent audits to ensure the industry is protecting reactor pressure vessels and internals. Failure to protect these important components can have downside risks not only to individual stations, but the nuclear industry as a whole. We are currently failing to meet the BWRVIP guidance on copper in the reactor coolant, which provides a spotlight on Columbia due to having one of the more significant program deviations. Peer pressure to eliminate long-term deviations is growing.

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Section 7: Solutions:

Deep bed demineralizers alone are not a preferred solution. They will reduce copper and impurities in the reactor coolant, but condenser leakage will continue to be a chronic problem and copper impurities will remain at a lesser amount. Unplanned downpowers and radiation exposure for condenser repairs will continue, but less

frequently. Resin usage and radioactive waste will increase due to the large size of the deep bed demineralizers. We also anticipate increased Security staffing due to an additional building to house the deep bed system.

On April 21, 2006 we entered into an agreement with Sargent & Lundy to perform a Feasibility Study on the main condenser. They recently did similar work for four Exelon BWRs and the Fort Calhoun Station. This will entail a comprehensive analysis of Columbia's history and that of the industry, resulting in recommendations to ensure long-term reliability of the main condenser. The study will be complete prior to the FY08 budgeting cycle. Engineering, design, and procurement are expected to start in FY08, with installation of some or all of the modification in R19 (FY09).

Condenser material replacement is clearly the preferred solution to eliminate leaks and copper sources, ensuring long-term reliability of Columbia's fuel, reactor vessel and internals.

For maximum protection and defensive strategy, installation of deep bed demineralizers in conjunction with condenser tube replacement is another solution. This is not currently under consideration. However, as the industry gains operating experience in fuels and materials degradation, the Columbia staff will stay abreast and take action as appropriate.

FIGURE 1
Circulating Water System
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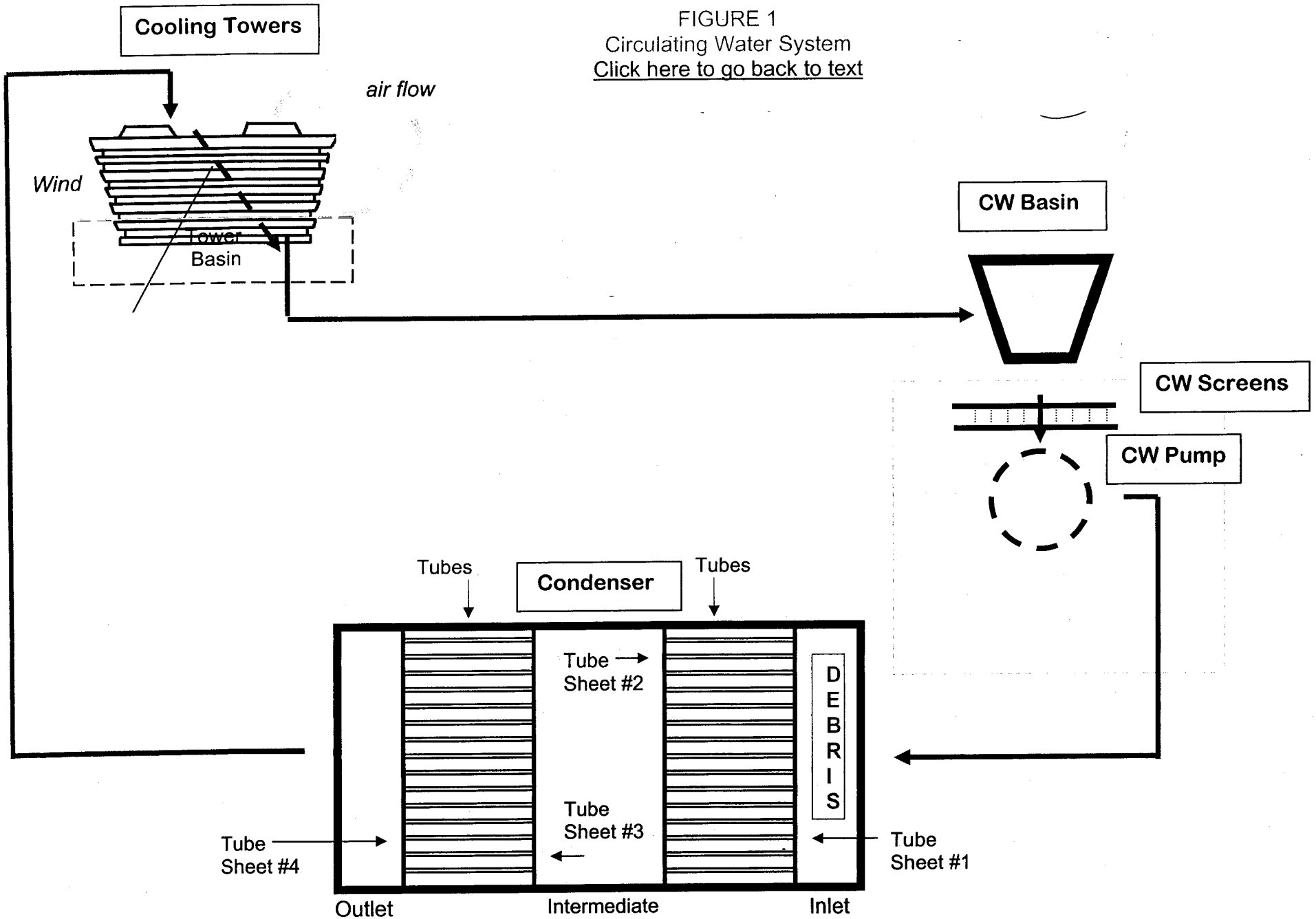

FIGURE 2A, Main Condenser Waterbox

Entry into the condenser waterboxes at power is a challenge to personnel safety. Single isolation valves (some eight feet in diameter) provide worker protection from system pressure. Entry is through small manways as shown in the picture.

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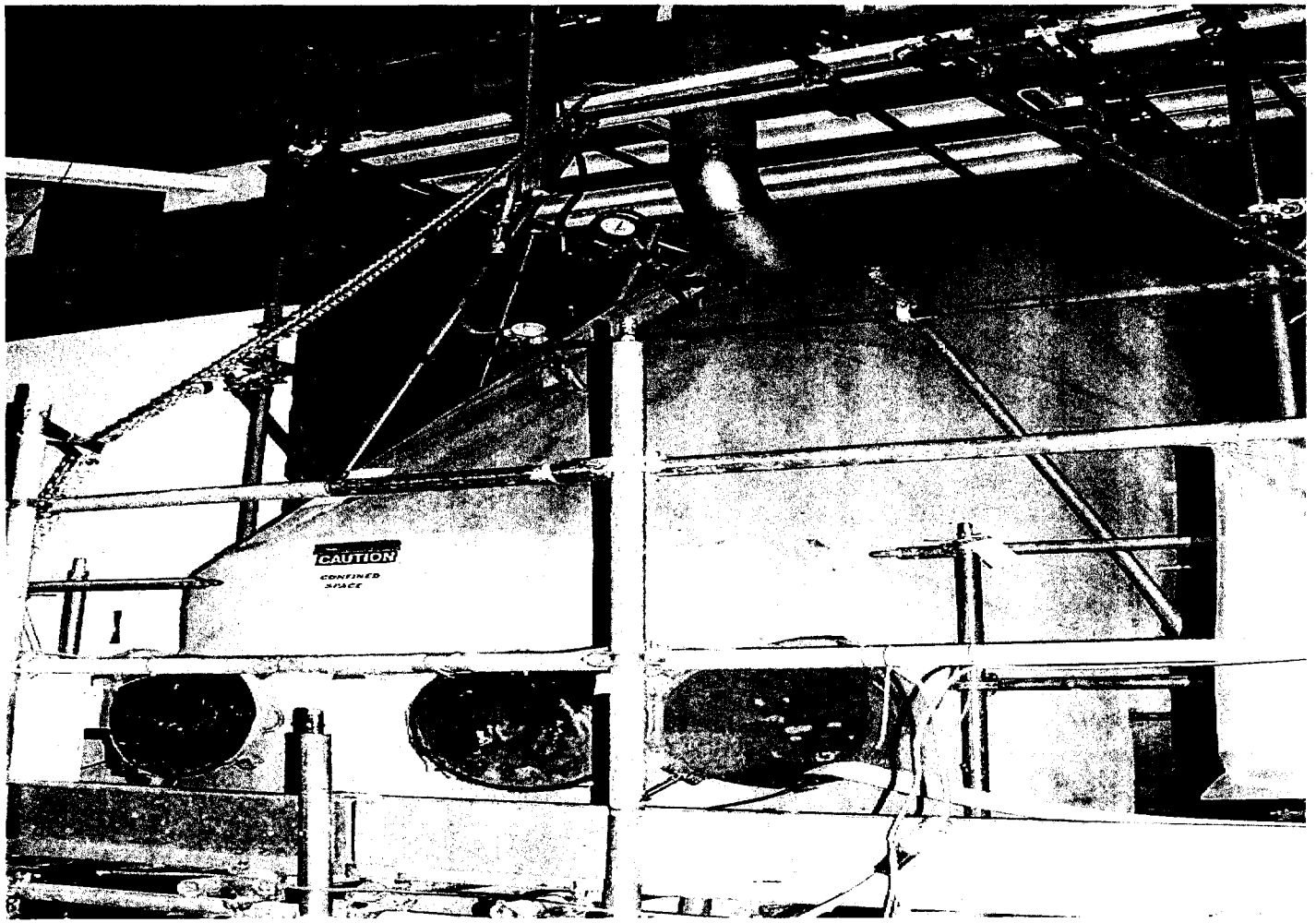

FIGURE 2B, Main Condenser Waterbox
This shows a worker inside the condenser waterbox.
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FIGURE 3, Fuel that has undergone CILC related failures.

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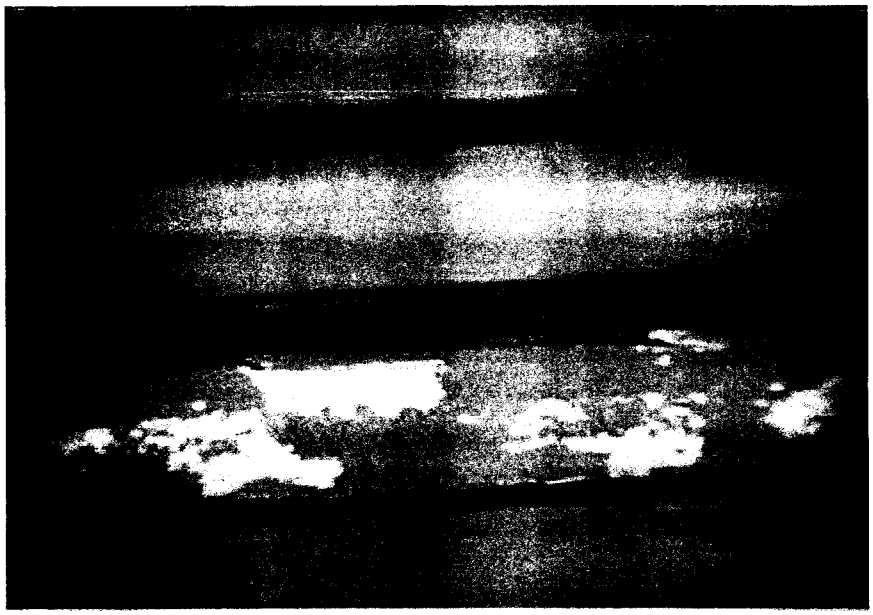

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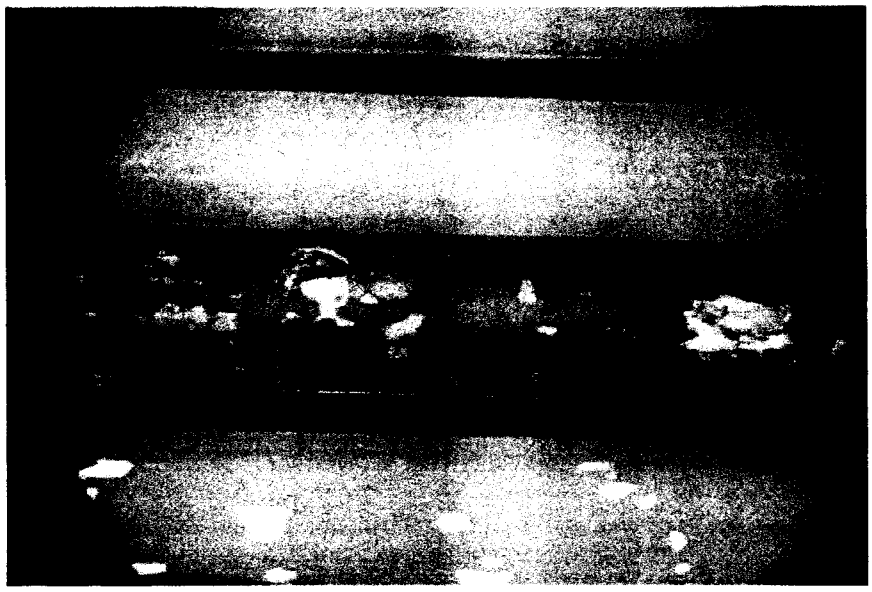

FIGURE 4, Failed fuel due to crud and accelerated corrosion.
This fuel was exposed to anomalous primary coolant chemistry, resulting in a heavy oxide layer and accelerated corrosion in 1999. It was fresh fuel.
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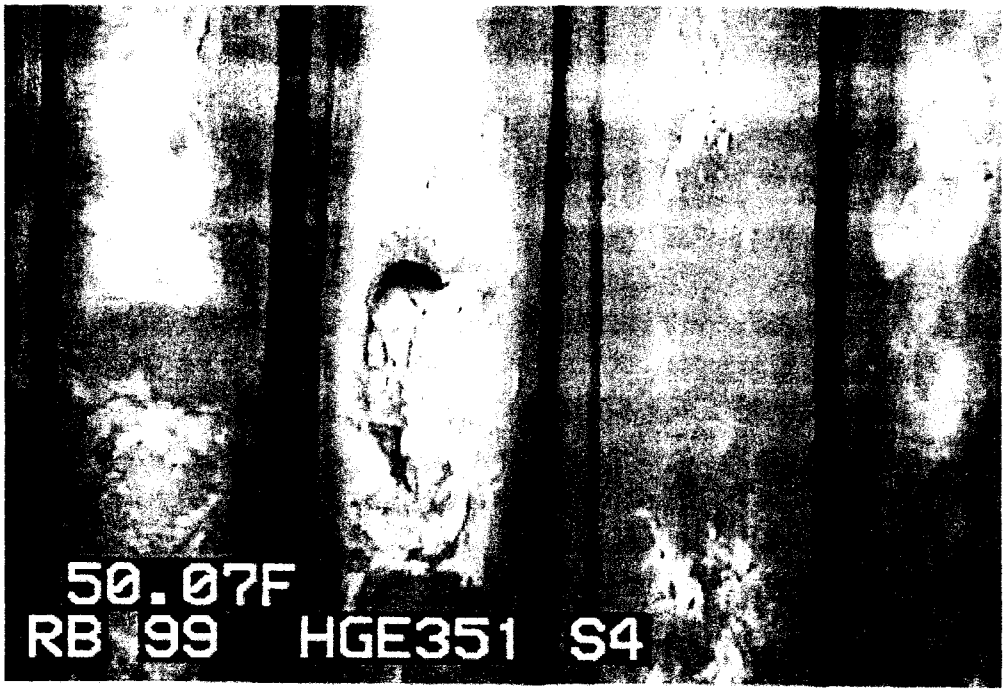

FIGURE 5A, One Cycle Fuel in expected condition.
The middle fuel rod has been brushed to remove the oxide layer.
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CGS 1-Cycle Bundle (Before Chronic Condenser Leak)

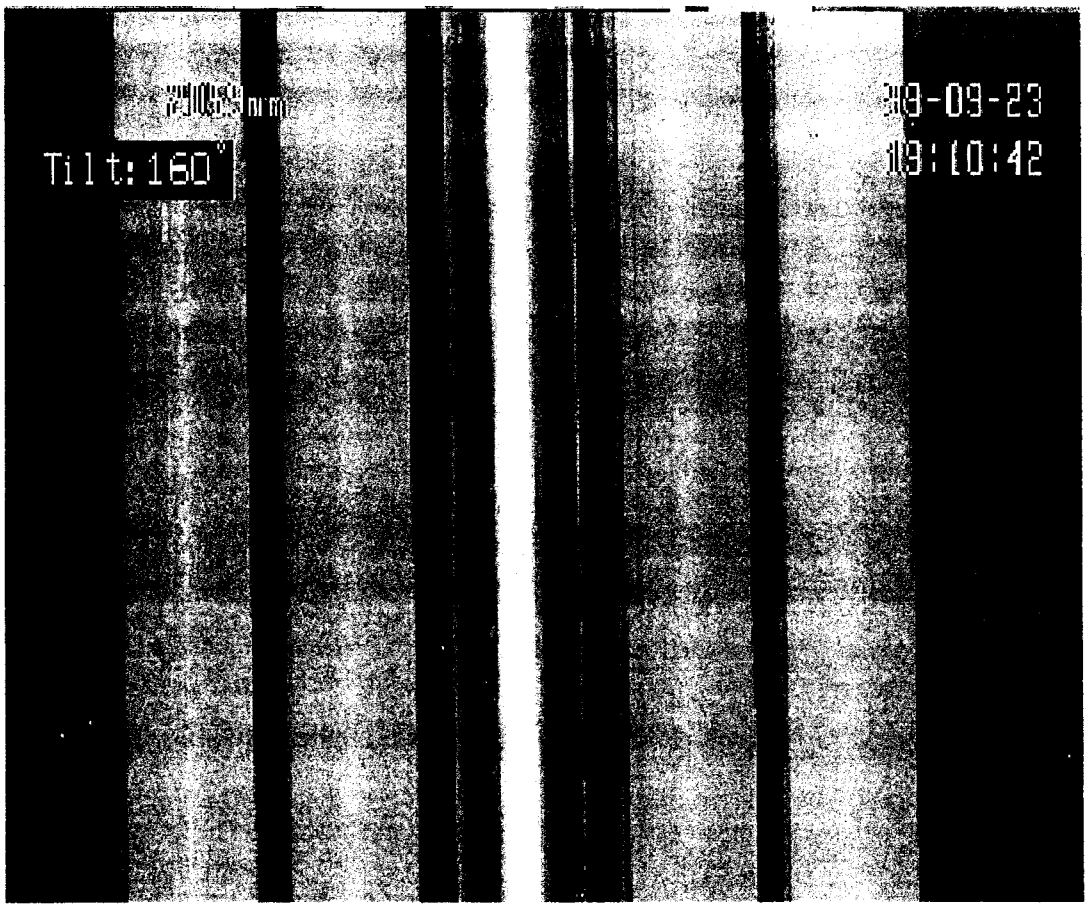

FIGURE 5B, One cycle fuel with it's oxide layer impacted by chemical contamination. Nodule formation has begun.

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CGS 1-Cycle Bundle (After Chronic Condenser Leak)

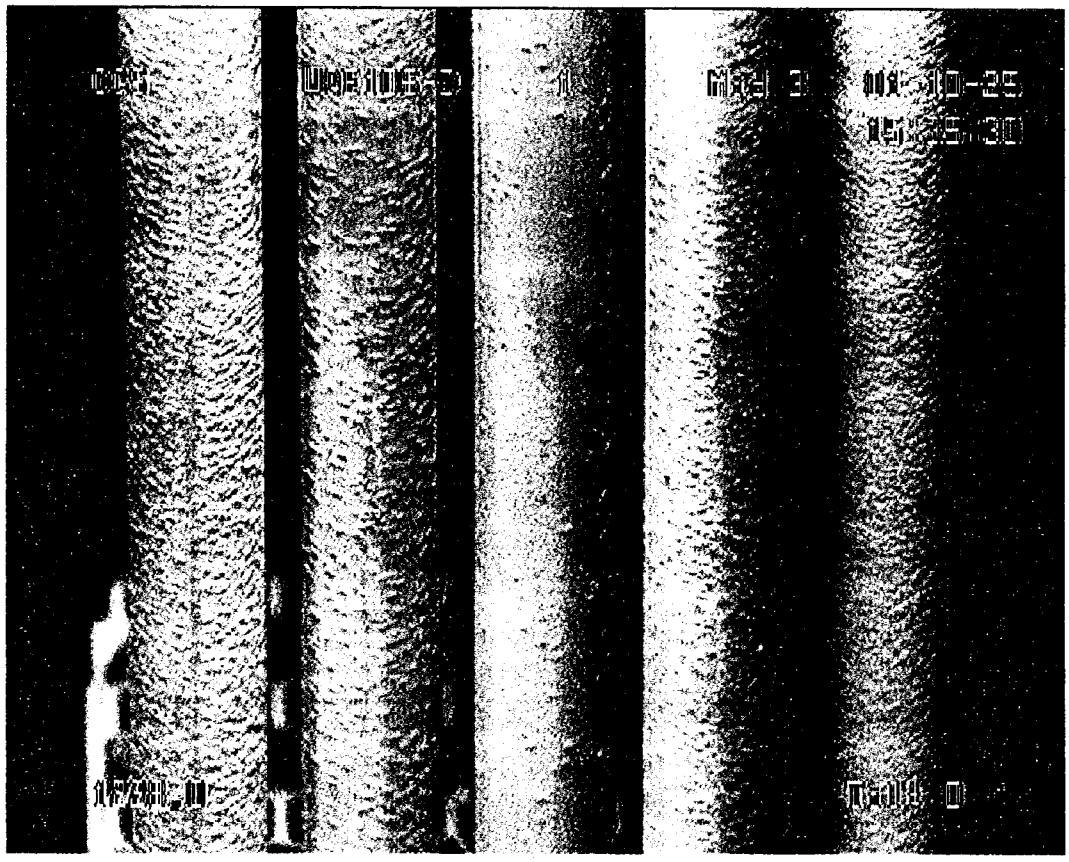

FIGURE 5C, Fuel that has been in the reactor for four cycles, following chemical contamination in the last cycle. Nodule formation and spallation is evident.
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CGS 4-Cycle Bundle (After Chronic Condenser Leak)

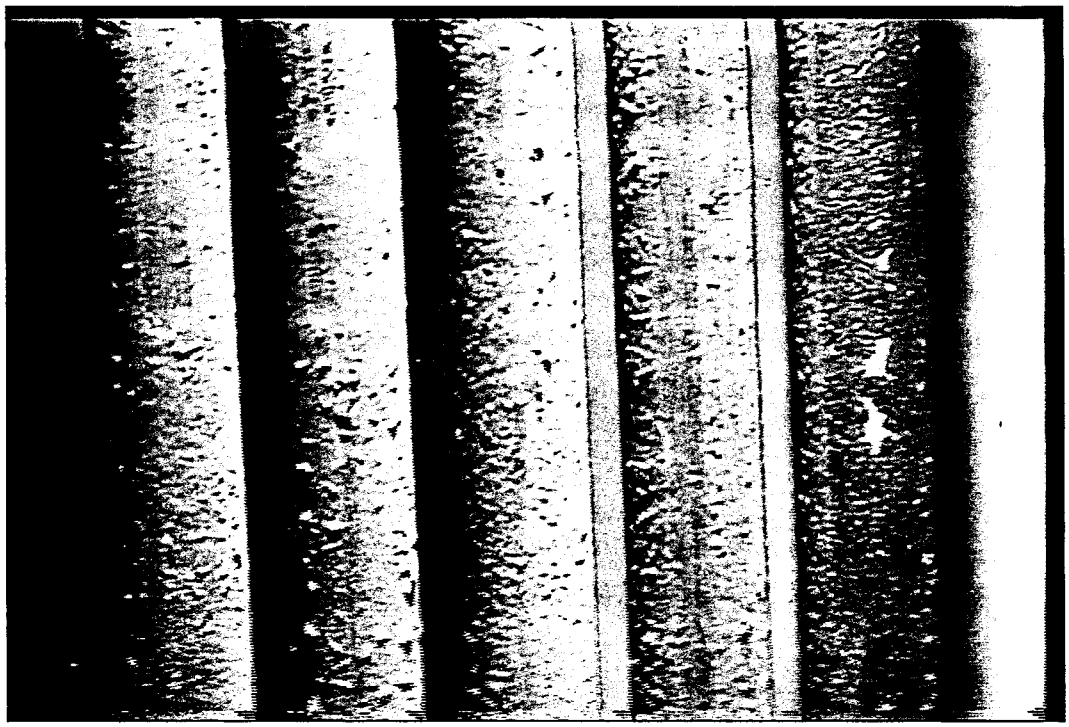

FIGURE 6A, Cooling Tower

As illustrated, the cooling towers have many openings to the environment that allow debris entry.

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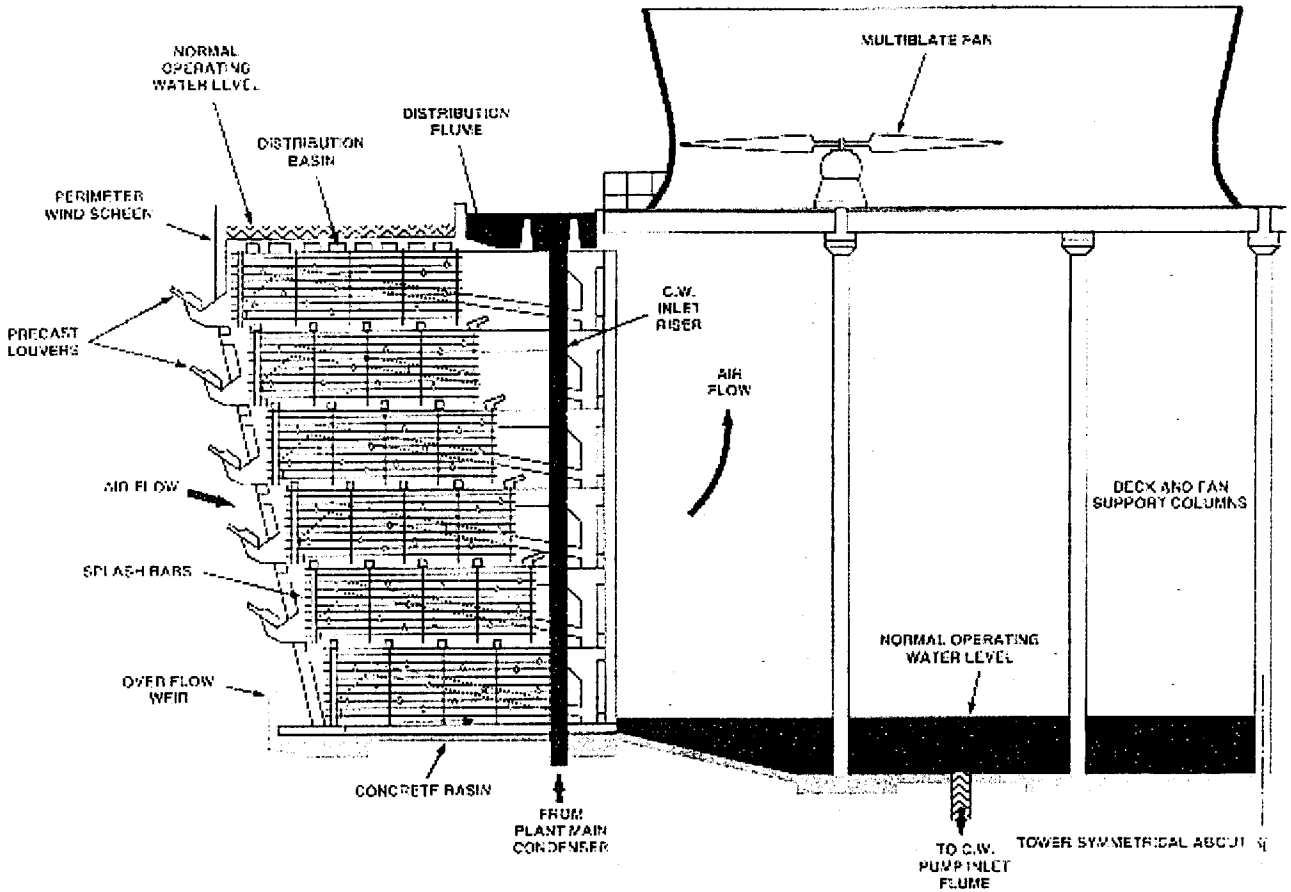

FIGURE 4. COOLING TOWER CROSS SECTION

FIGURE 6B, Cooling Tower.
Large fans and vertical louvers allow debris entry pathways.
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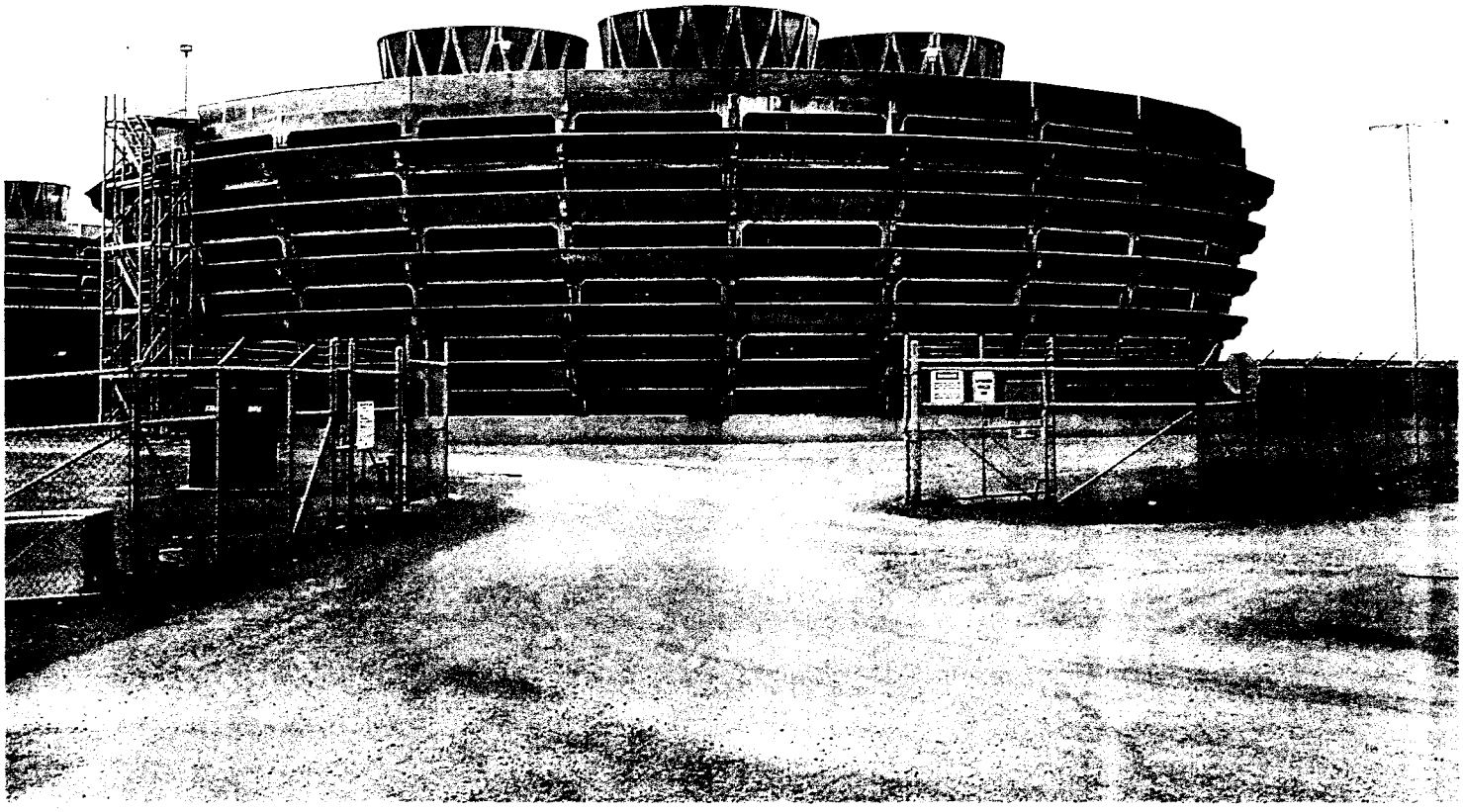

FIGURE 6C, Cooling Tower
Inside a drained Cooling Tower. Workers are careful to remove debris prior to returning it to service.

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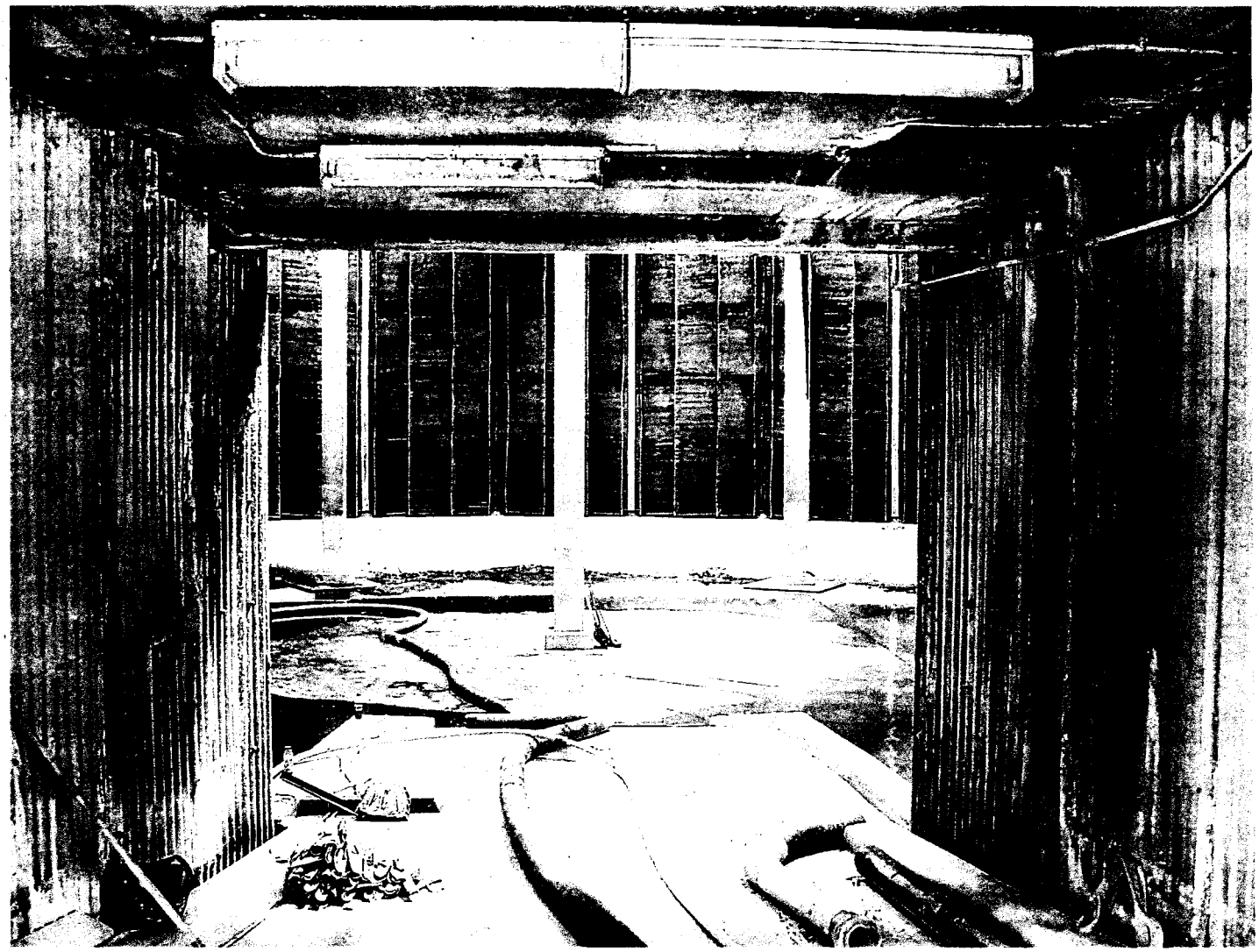

FIGURE 6D, Cooling Tower.
This drained Cooling Tower demonstrates how open to the environment they are. When in service, water fills these passages and falls to the basin below.

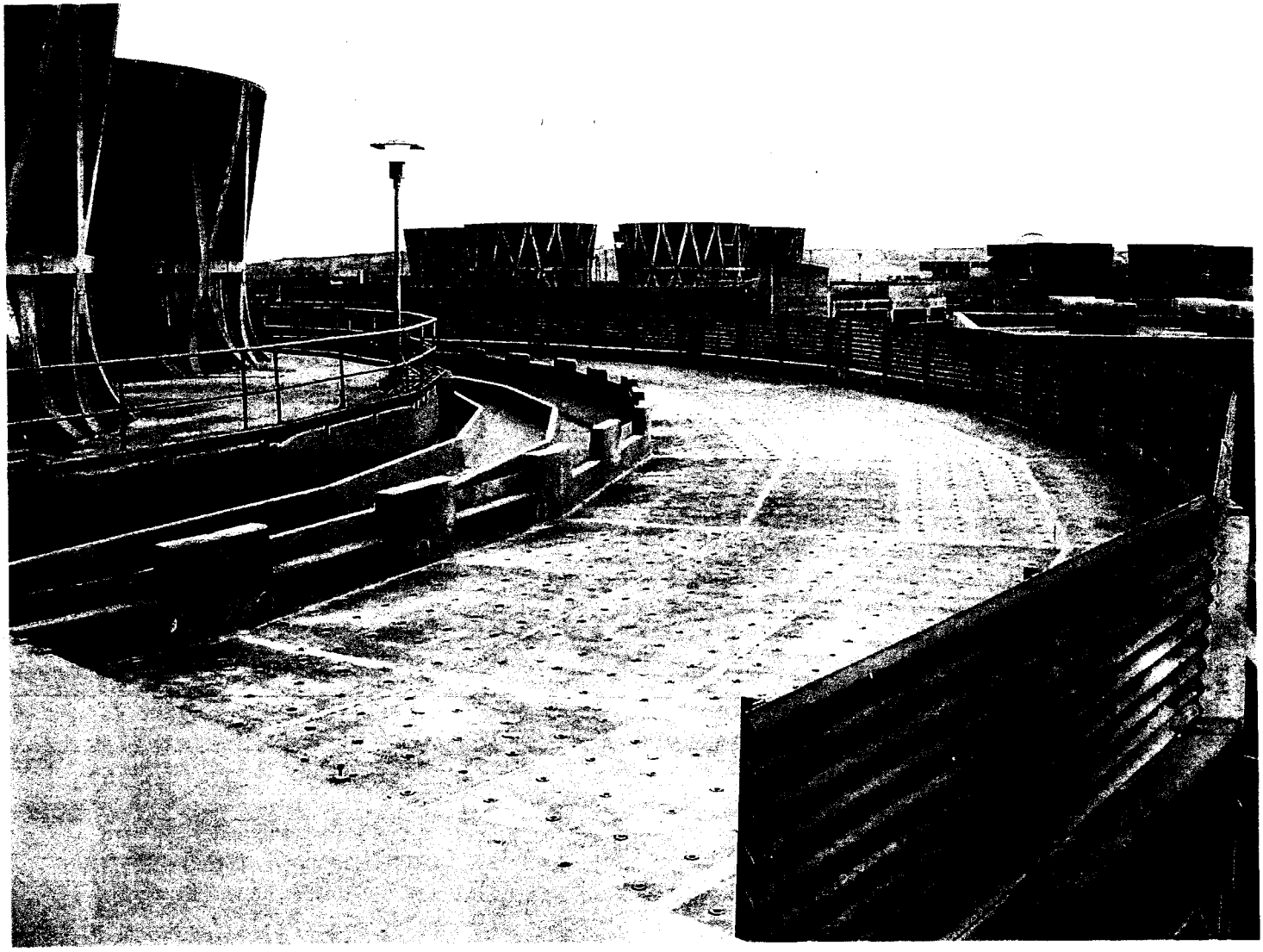

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FIGURE 7, FERMI Condenser Replacement Article

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FERMI 3

INDUSTRY NOTES
PROCESS/MANUFACTURING/UTILITIES

Steam generation

Preplanning, analysis key to condenser retubing

Degradation of condensers and the potential for forced outages or plant load reductions demand that utilities continually evaluate the possible need for condenser upgrading. A particular problem at nuclear powerplants has been high copper levels in the feedwater system, which has been tied to steam-generator corrosion in pressurized-water-reactor (PWR) plants and fuel-assembly corrosion in boiling-water-reactor (BWR) plants. Experience shows that radioactive contamination, increased personnel exposure to radiation, and significant loss of plant availability can result.

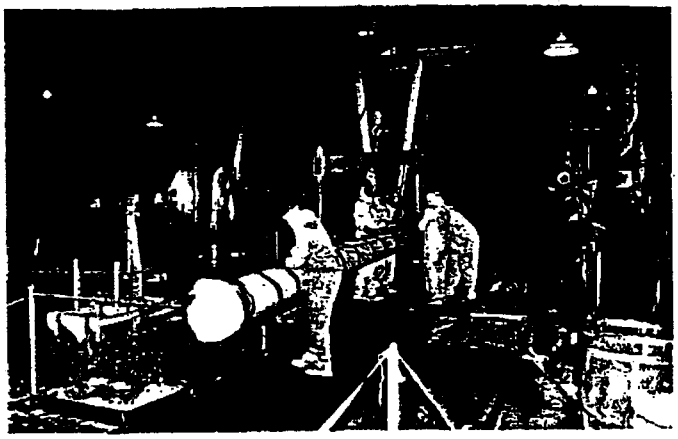
Fermi Unit 2, a BWR plant of Detroit Edison Co, is located on Lake Erie, a freshwater body of relatively good quality. The plant has a closed circulating-water system (CCWS) that relies on the lake for makeup. The CCWS comprises a pond, five circulating-water pumps, an Admiralty-brass-tubed, single-pass condenser, and two natural-draft cooling towers. General utility experience indicates a 12-15-yr expected condenser life for this material/system combination, limited primarily by erosion resulting from solids in the system.

Of 25 US and foreign BWR plants having condensers with Admiralty brass tubing, 17 have experienced crud-induced localized corrosion (CILC) of fuel-element cladding—in some cases resulting in fuel leaks and system contamination. Feedwater copper levels exceeding 0.2 ppb have been identified as a significant contributor. Problem condensers have been or will be replaced with stainless steel in three of the afflicted plants, and with titanium in 14.

While use of filter/demineralizers to control feedwater-copper buildup is one preventive approach, Leonard C Fron, the utility's condenser project manager, notes that limiting copper to levels down to 0.2 ppb adversely affects demineralizer run times and increases requirements for radwaste processing and waste disposal/storage. Removal of the source of copper provided the best long-term solution.

A decision was made to retube the condenser in December 1989, and the modification was targeted for the refueling outage (RF02) scheduled for March 1991. A formal project organization was set up in January 1990 to study, detail, and implement the modification, the staff functioning as a completely self-reliant entity both before and during the outage. In addition to Fron, key staff members were John Honkala, condenser project engineer, and John O'Donnell, condenser field engineer.

With the loss of generating capacity a key concern, the first order of business focused on the length of the outage. In the past, retubing of BWR plants of similar size and condenser-tube number has required from 75 to 110 days—less for condensers with significantly fewer tubes or for partial condenser-tube replacements. The selected outage provided a 65-day window for the project. This required an aggressive construction schedule and intensive, detailed preplanning.



Radioactive contamination on tube surfaces and in condenser areas demanded special precautions for personnel protection

Using previous historical data and input from Fermi 2, a utility consultant developed a construction schedule allowing 75 days from entry into waterboxes to completion of the concluding circulating-water test. Allowing for pre-outage work, use of separate stand-alone facilities, and sharp focusing of the job to minimize interferences from other outage activities, the project team shortened the schedule to 65 days. Ambitious as it may have seemed, this requirement was incorporated into the project specification, so bidders were prepared to present detailed 65-day schedules at the pre-bid meeting.

In accordance with utility policy for major contracts, the team established a fixed-price contract for retubing the condenser and developed a detailed specification, the heart of the contract. This did not preclude the requirement of prices for specific activities, manpower loading, a milestone schedule, and a detailed activity schedule. A detailed reference bid, moreover, was prepared to provide a basis for excluding low bids from contractors with marginal experience.

This strategy resulted in two very good proposals, and the award decision was based primarily on the contractor's management team and its experience in working together on similar projects. Success of the approach is measured by the fact that the project was completed ahead of schedule with a quality product and only 3% in additions to the original contract price.

Such an achievement, clearly, could not have been accomplished without a thorough analysis of the problems involved, evaluation of the available options and associated limitations, a detailed and realistic project schedule, and complete agreement on job-specific activities—all predicated on creation of a close-knit team with a unified approach.

This was accomplished over a period of nine months starting in July 1990, when the contract was awarded to United Engineers & Constructors/Catalytic, Philadelphia, Pa, and organizational interfacing commenced. Beginning in September, the general contractor and its subcontractors—Heat Exchanger Systems Inc, Boston, Mass, and Cannon-Sline, Philadelphia, Pa—worked closely with the project team to prepare a detailed schedule, locate providers of goods and services, and conduct the necessary analyses related to tubesheet stability, tube/tubesheet-joint strength, and protective-coating evaluations. So close and smooth were the interactions among involved personnel during this period that, by December 1990, they

were no longer identified by their individual organizations but as the Condenser Project Team.

Project elements. The primary considerations of the project were selection of the tube material and the replacement method. The replacement material would have to equal the plant's performance experience with Admiralty brass: operation close to design rating with fewer than 1% of the tubes plugged and fewer than 1% with 50% wall thinning. Other materials-related concerns were susceptibilty to corrosion, erosion, and fouling of the internal surface.

Non-copper-based materials evaluated included Types 304 and 316 (austenitic), Type AL6XN ("super" austenitic), Type 439 (ferritic) and Sea-Cure ("super" ferritic) stainless steels, and titanium. The austenitic steels were not considered suitable because of the need for water-side layup procedures. Type 439 was eliminated because of susceptibility to pitting and crevice corrosion. Although the costs of the "super" stainless steels and titanium were comparable, titanium was selected because it has never failed from corrosion in powerplant condenser service. Its use for tube replacement in 14 BWR condensers, moreover, has been successful.

Replacement alternatives were rebundling, retubing only, and retubing with new tubesheets. Replacement of tubes as groups (bundles)—done with great success at several Scandinavian nuclear plants—was not possible at Fermi 2 because of the plant layout and interferences. This required hand removal of tubes, negating schedule advantages offered by modular replacement.

Despite galvanic incompatibility, it was decided to retain the existing carbon steel tubesheets, primarily because the condenser has center outlet waterboxes, which would have had to be dismantled to install titanium outlet tubesheets. The inlet tubesheets could have been replaced by removing the inlet waterboxes and cutting the tubesheet-to-condenser-shell weld. But this would have had to be replaced by a mechanical joint, introducing a potential for leakage.

Analysis of tubesheet and tube-joint loads indicated no significant change would result from retubing with titanium. Joint-strength tests were conducted to determine the acceptable tube-rolling torque under the allowable 1340-1590-lb forces expected at 55 psig, the design pressure of the circ-water system. Five 88-hole mockup tubesheets were made for pullout tests, two of them epoxy-coated to replicate the intended retubed-condenser tubesheet end-product. About 10% of the titanium tubes tested were coated with Loctite prior to rolling. Test results dictated rolling torques of 10.5 and 11 ft-lb at the inlet and outlet, respectively. Based on the worst-case pullout forces, these torque values produced a tube-to-tubesheet joint with a safety factor of two.

Additional analyses were related to condenser uplift, cathodic protection, tube vibration, and effects on circulating-water flow. Structural stability was a factor because the full complement of 22-BWG titanium tubes would be over one-million pounds lighter than their predecessors. Analysis showed that resulting uplift loads could be accommodated by the existing foundations, anchorage, and structure. Tests to determine the need for cathodic protection because of metal dissimilarities concluded that the tubesheet could be protected from galvanic corrosion by coating alone, without use of a sacrificial anode or impressed-current cathodic protection.

Corrosion calculations based on measurements made on test assemblies placed in the circulating-water pump house indicated expected corrosion rates below 10 mils/yr. Because other approaches were cost-prohibitive, and assuming no coating imperfections or failures, it was decided that a thick film coating with high impact resistance and excellent flexure, cathodic-disbondment, and dielectric-strength properties would provide adequate tubesheet protection.

Tube-vibration analysis indicated that the unsupported span length of the thinner-walled titanium tubes would have to be reduced to prevent vibration-induced failures. This dictated the need for staking the tubes, confirming the experience at other plants. Tubes in the air-cooler sections were not included because of the far lower velocities that they would be subjected to and the amount of work involved in installing stakes in these shrouded sections.

Type 304 stainless was chosen over other possible staking materials for its smooth surface finish, corrosion resistance, and ease of installation. A dimpled stake design was selected because it offered a locking capability. The pattern developed for full bundle staking required about 36,000 stakes of varying length.

Analysis of circulating-water flow indicated little impact on tube cleanliness, condenser pressure, or net generation would result from the reduced tube velocities in a titanium-tube condenser—from 7.05 ft/sec to 6.53 ft/sec with five pumps operating, from 6.28 to 5.80 ft/sec with four pumps. Velocities were judged adequate to maintain tube cleanliness factor at an estimated 90%. No appreciable increase in net generation would occur with five pumps until the circulating-water inlet temperature reaches 75F or higher.

Remaining uncertainties had to do with the condition of circulating-water valves, inlet and outlet tubesheets, condenser steam side, and support plates. Possible concerns included valve leakage, support-plate bowing, and microbiologically influenced corrosion (MIC) of tubesheets. The valves were cleaned, inspected, and adjusted for seating during several forced outages. Tubesheets were also inspected and special tube-work tooling determined. Steam-side condition was established and damaged components were fabricated before the start of RF02. The presence of rust nodules indicated areas of MIC.

Selection of the tubesheet coating required extensive research into the need for surface preparation before application of the coating. This was dictated by reports indicating premature coating failures were likely in MIC-affected areas if corrosion and bacterial colonies were not removed before the coating was applied. Possible solutions, ranging from ozonation to arrangement of steam chambers and flushing of tubesheet surfaces with potable water, appeared cost- and labor-intensive; limited documentation was available to provide bacteria counts before and after treatment to verify the effectiveness of efforts at eradication.

Accordingly, a treatment process was developed that would not impact the schedule nor be toxic to personnel or the environment. It involved hydroblasting, spraying with hydrogen peroxide, sandblasting, and washing with methylethyl ketoxime (MEK). A mockup tubesheet was prepared, Admiralty brass tubes were rolled in, and the assembly was immersed in circulating water on the pump suction side for six weeks, allowing buildup of a slime and corrosion layer similar to that developed on the condenser tubesheets. Examination of the assembly before treatment revealed the presence of corrosive-acid-producing bacteria.

The examination was repeated after each step of the eradication procedure. The end result was that 94% to 99% of the bacteria population was killed by hydroblasting, and another 2% by the peroxide wash. Following the MEK wash, total kill was 97% to 99%. This analysis enabled the elimination of MEK from the procedure. Before implementing the procedure during the outage, water samples were taken from MIC-affected areas for baseline data. Comparison to samples taken after hydroblasting—allowing time for bacterial growth—showed a 75.2% reduction in the bacterial colony count; the reduction achieved by hydroblasting followed by peroxide spraying was 97.8%.

The balance of the detailed pre-outage planning and activities called for by the retubing specification proceded on or ahead of schedule. As a result, the 60,000-tube condenser was retubed, coated, and tested in a period of 62.5 days with near-flawless workmanship. The work was completed 2.5 days ahead of schedule and 20% under the budgeted cost—all the more notable for having been achieved despite complicating conditions: contaminated tubesheets, radioactive tubing, and the use of special clothing to protect personnel from contamination at the waterbox faces (see photo).

Shel Strauss

6/6/06
EN News

3. **Replaced 10 valves - FW checks, RHR checks, CS checks, and (2-3) RWCU valves.**
4. **Fixed their maintenance practices.**
5. **Optimized RWCU's, CFD's, and Zinc addition.**
6. **Final chemical decontamination.**
7. **Made both their employees and contractors ALARA conscience.**

Hatch is now in the top quartile (CRE) and has not performed a chemical decontamination since 1997. This information should show you more than anything else that your plan will work if you work your plan – together. As my father used to tell me, "It's not rocket surgery."

I have enjoyed working here this week and enjoyed speaking with each of you. During my interviews with craft, salaried, management, and contractors I was exposed to over 500 years in nuclear experience (so you know I stole some good ideas). The employees were forthcoming with their ideas and concerns, which is a credit to the station.

CGS main condenser feasibility study

Dolly Richendrfer, Communications Specialist

Energy Northwest has retained the services of Sargent & Lundy LLC of Chicago, IL, to perform a feasibility study on proposed modifications to the Columbia Generating Station main condenser. A worldwide leader in professional services for the electric power industry, Sargent & Lundy has done similar work at four Exelon Boiling Water Reactor design nuclear stations, as well as the Fort Calhoun Nuclear Station. Results of the CGS study will be published prior to the Fiscal Year 2008 budgeting cycle.

A number of condenser modifications are under review due to recurring problems with condenser leaks caused by a variety of factors, including design limitations, original condenser materials, and other debris. Repair of these leaks has been costly in terms of lost generation as a result of having to either reduce power or shut down the station, as well as increased radiation dose rates for employees. The costs of not addressing these issues are even greater and could have a long-term negative impact on the station and the region.

Columbia Generating Station management has taken a number of steps to address these issues for the short term; however, Energy Northwest must determine the best course of action to definitively address the situation and enable the station to operate for an extended period of time.

Two detailed overview documents about this project have been published on the Energy Northwest website at www.energy-northwest.com. To view the documents, click on **News & Information**. These documents are listed and available under the heading, **Columbia Generating Station Information,** and are entitled Main Condenser and Addendum 1.

ACES Observer Training Classes

This comes from Alan Sage, ACES Program Coordinator.

With the summer months upon us, so are a lot of vacation plans. The ACES process raises your safety awareness at work, at home and, yes, even while on vacation. What better way to start your vacation then to prepare for you and your families safety.

The Steering team would like to invite those that have not yet attended to register in Plateau through you Admin Assistants. There are still openings in all the classes throughout the summer months.

The next class for will be Wednesday and Thursday, June 14 and 15, class ID 2378. Hope to see you there.

Columbia Generating Station
Main Condenser, Addendum 1

W. Scott Oxenford, VP Technical Services

This addendum augments the Columbia Generating Station Main Condenser white paper, providing a summary of economic impacts of condenser leakage.

The analysis is organized in two parts for clarity. The first provides an average cost per event or month. The second provides a cost breakdown over the current operating cycle, from June 2005 through May 2006.

Historical Perspective

Columbia has suffered eleven shutdowns and nine reduced power evolutions to address main condenser leakage since it began operation in 1984. The number of events speaks to the chronic nature of this costly operational challenge.

Condenser related shutdowns and down-powers would have been even more frequent if it were not for repeated plant shutdowns, extended economic dispatch periods due to river flows, and annual operating cycles. Each of those operational attributes provided opportunities to perform condenser repairs reducing the potential for even more condenser related shutdowns.

Direct Cost Impact

Chemistry Control

Columbia's condensate filter demineralizers are changed more frequently to minimize impurities reaching the reactor pressure vessel. The demineralizers are coated with a powdered resin. The costs of increased resin use, shipment, and disposal of the associated radioactive waste is included. Additionally, the circulating water system is operated to reduce the level of impurity concentration, requiring increased chemical treatment.

$124,000/month
Average chemistry-related cost for each month Columbia operates with a condenser leak.

$1,030,000
Aggregate chemistry-related cost for this operating cycle (June 05 to May 06).

Tube Plugging Evolution

A tube plugging evolution is performed at reduced power and takes about three days. Detailed planning, oversight, and around the clock coverage limit lost generation. The actual tube plugging activity involves isolating a section of the

condenser, draining it with multiple pumps, cleaning the tubes, identifying the leak(s) and inserting plugs. The evolution involves Columbia staff level of effort, overtime, and the use of contractors.

$350,000/evolution
Average incremental direct costs associated with one tube plugging evolution.

$1,400,000
Aggregate cost of the four tube-plugging evolutions this operating cycle (June 05 to May 06).

Indirect Cost Impact

Radiation Exposure

Columbia's main condenser location exposes personnel to radiation during repairs. Keeping radiation exposure 'as low as reasonably achievable' is everyone's responsibility.

Radiation exposure is closely monitored by Energy Northwest, the Nuclear Regulatory Commission, and the Institute of Nuclear Power Operations. A non-outage month at a top performing boiling water reactor is less than 2 Rem collective radiation exposure, with a total for the year of around 30 Rem. Adding one condenser repair evolution jeopardizes the annual goal of 30 Rem or less.

2.262 Rem/evolution
Collective radiation exposure to Columbia staff and contractors, per tube plugging evolution this operating cycle (June 05 to May 06).

9.048 Rem
Collective radiation exposure to Columbia staff and contractors this operating cycle (June 05 to May 06).

Replacement Power

Columbia conducts tube plugging evolutions at 65% power. Based on typical duration, a tube plugging evolution costs us the equivalent of one day of full power operation. Estimating the value of power of $32.45/megawatt hour produces the following indirect costs.

$1,000,000/evolution
Estimated cost of replacement power per tube plugging evolution.

$4,000,000
Estimated cost of replacement power for tube plugging evolutions this fiscal year (July 05 to June 06)

Costs for 2001 Heavy Oxide Layer Analysis

Columbia's staff had extensive fuel rod corrosion related concerns in the 2001 timeframe. A highly experienced industry team was formed to determine the root cause and initiate corrective actions. Condenser leakage was identified as the root cause.

$1,750,000
Cost associated with fuel scrapings, investigation, and research into heavier than expected fuel oxide layer.

One corrective action from the above investigation was to alter Columbia's chemistry controls to favor fuel protection over radiation source term mitigation. The strategy was followed until the current operating cycle. Oxide formation on the fuel during this test period was normal, thereby validating the root cause determination. Favoring fuel protection created very high radiation source term at Columbia, resulting in increased staff radiation exposure. The impact is difficult to quantify, but very real. Columbia's radiation exposure performance is in the worst quartile in the industry. Columbia is currently the worst plant based on source term measurements. To counteract this, a chemical decontamination of key piping is scheduled for our upcoming outage.

$1,700,000
Approximate cost of chemical decontamination in the upcoming outage to improve radiation source term.

Replacement Power Estimates Since 2000

Lost power generation (associated with main condenser leakage) since January 1, 2001 is equivalent to more than 12.5 days of full power operation. With an estimated value of power of $32.45/megawatt hours, the total cost is substantial.

$12,500,000
Estimated value of replacement power associated with Columbia main condenser leakage events since January 1, 2001.

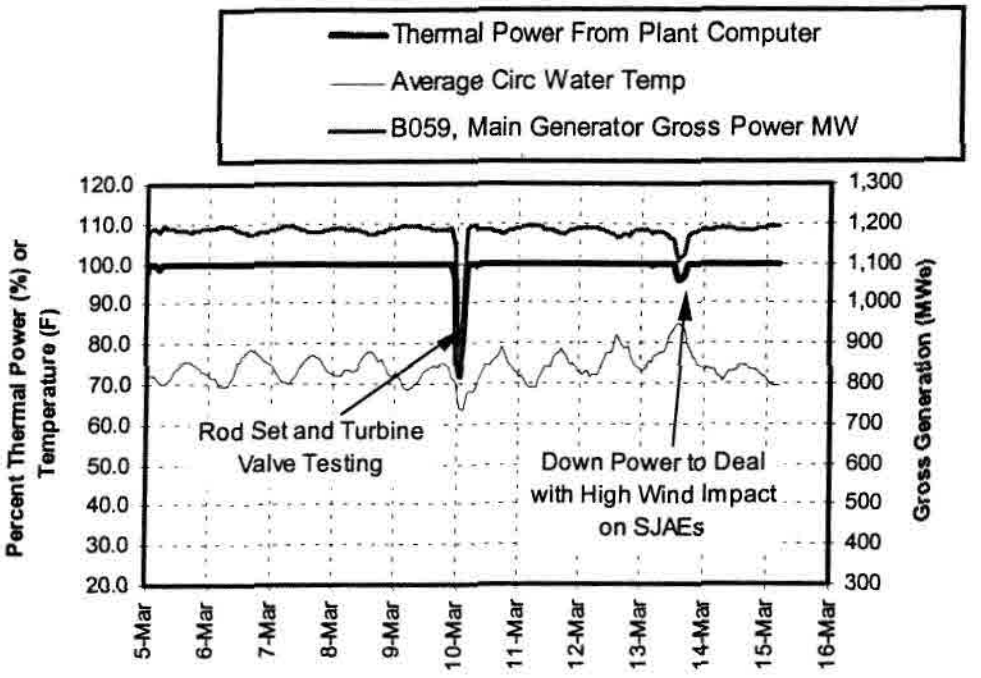
Conclusion

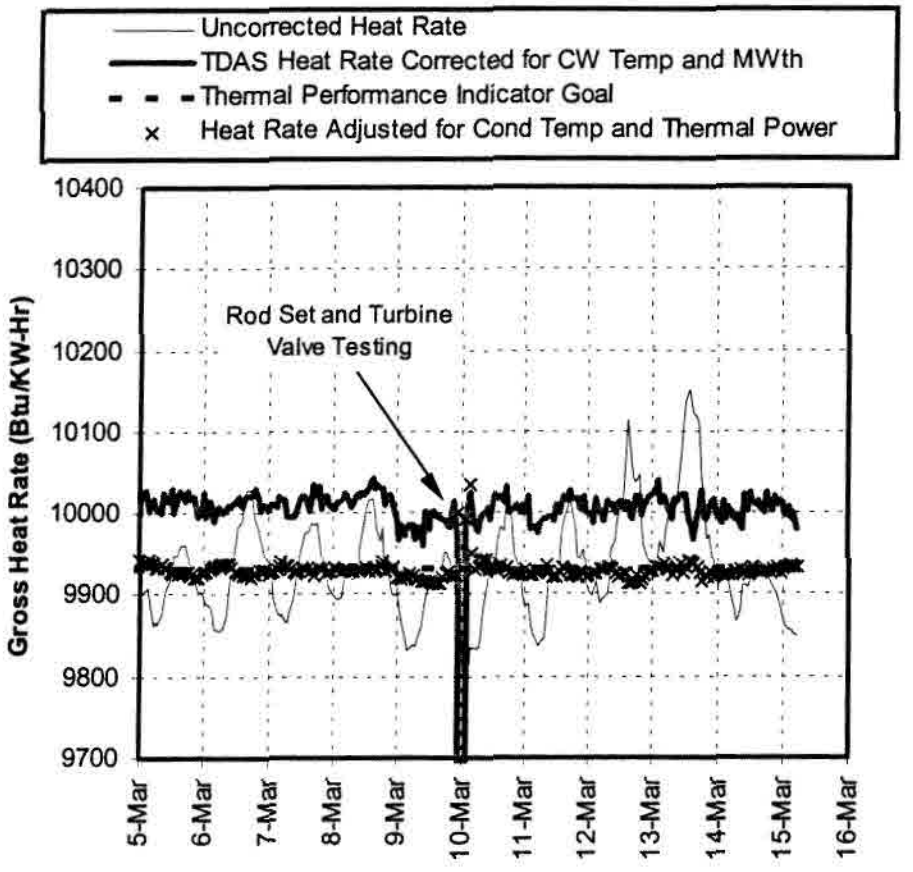
Various conclusions can be drawn from the above data. In simple terms, the author draws the following underlying conclusion, upon which others can build.

> "The design and resulting poor performance of Columbia's main condenser has produced many direct and indirect costs and continuously challenged our ability to achieve operational performance levels expected of U.S. nuclear power plant operators.

The chronic nature of Columbia's main condenser problem is unlikely to change substantially without addressing the condenser tube material. Failure to address this issue will increase the risk of fuel damage. That fact alone is ample reason to replace the main condenser tubes. Replacement is also in the best interest of efficient financial operation of the plant as evidenced by the costly history of our present condenser equipment."

Columbia Generating Station Thermal Performance Data





Thermal Performance Charts for the week ending at midnight on 3/13/2001

Top Chart – Generation Data

- The bold line on the top chart is a plot of percent core thermal power, 3486 MWt = 100%
- The gray line on the top chart is a plot of gross electrical power. Gross electrical power production capability is partially a function of environmental conditions. The colder, drier, and calmer it is, the more electrical power the plant can produce.
- As an indication of overall environmental conditions, the circulating water return temperature is plotted as a fine solid line, also in the upper chart. The colder, drier, and calmer it is outside, the colder the circulating water is. The electrical generation line should rise and fall opposite of but in step with the circulating water temperature.

Bottom Chart – Plant Heat Rate Plots

- The fine black line is a plot of our uncorrected gross heat rate in Btu/kW-Hr. Because the electrical generation is affected by environmental conditions, the heat rate shows rises and falls dramatically. High circulating water temperature results in high heat rate and vice versa.
- The bold gray line is a plot of the gross heat rate corrected for circulating water temperature. Normally this is the best measure of the health of the turbine cycle from the governor valves to the condenser and back through the feedwater heaters. The purpose of this line is to try to filter out environmental effects. It should typically run between 9925 and 9950 for WNP-2. This week the line is based on the TDAS gross generation signal because of drift in the PPCRS signal that is normally used. Power correction becomes CW temperature dependent (and therefore less accurate) as power is reduced. This line is not included at power levels below 80%
- The data presented as black 'X's is the temperature corrected heat rate based on the condensate temperature. Heat rate corrected to condensate temperature is being tracked while condenser performance is in question to give an indication of the health of the remainder of the steam cycle equipment. This line is not included at power levels below 80%

Columbia Generating Station entered the period at full power and remained there for the week with the exception of two short shallow down powers late on the evening of the 4th and early on the morning of the 5th. The down power evolutions were to deal with high dP across the filter demineralizers.

The MDC capacity factor as calculated through the 13th of March was:

Month to Date = 101.1%
Fiscal Year to Date = 92.8%
Calendar Year to Date = 101.9%
Between Refueling Outages = 91.9%

The Capability factor as calculated through the 13th of March was:

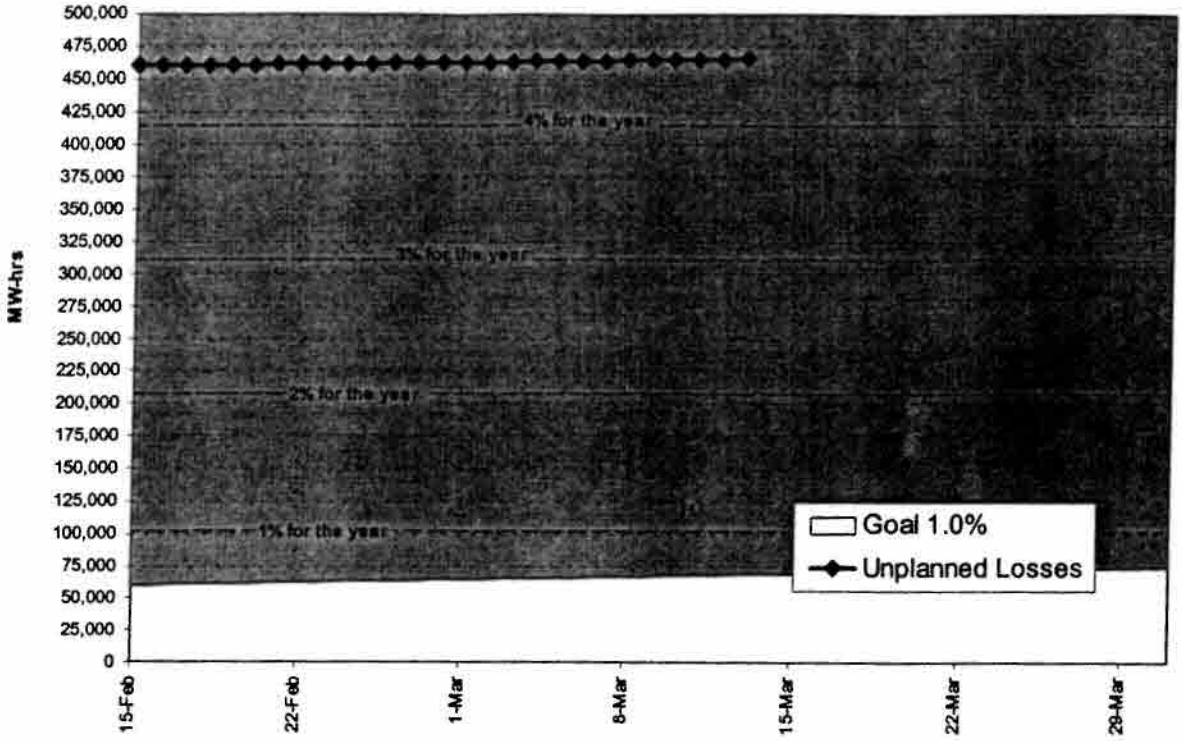
Month to Date = 99.6% (98.8% if condenser losses are real)
Fiscal Year to Date = 93.4%
Calendar Year to Date = 99.5%
Between Refueling Outages = 94.9%

If there are questions concerning this data please call Dave Krieg (x4249).

NOTE: Updated performance indicator charts for electrical generation, thermal performance indicator graphs, and an updated list of capability losses for the cycle can be found on the Energy Northwest intranet. From the home page click on "News" then click on "Perform Indicators" then "Generation".

Cumulative Unplanned Capability Losses for FY01

(Detail of Last Four Weeks Shown)

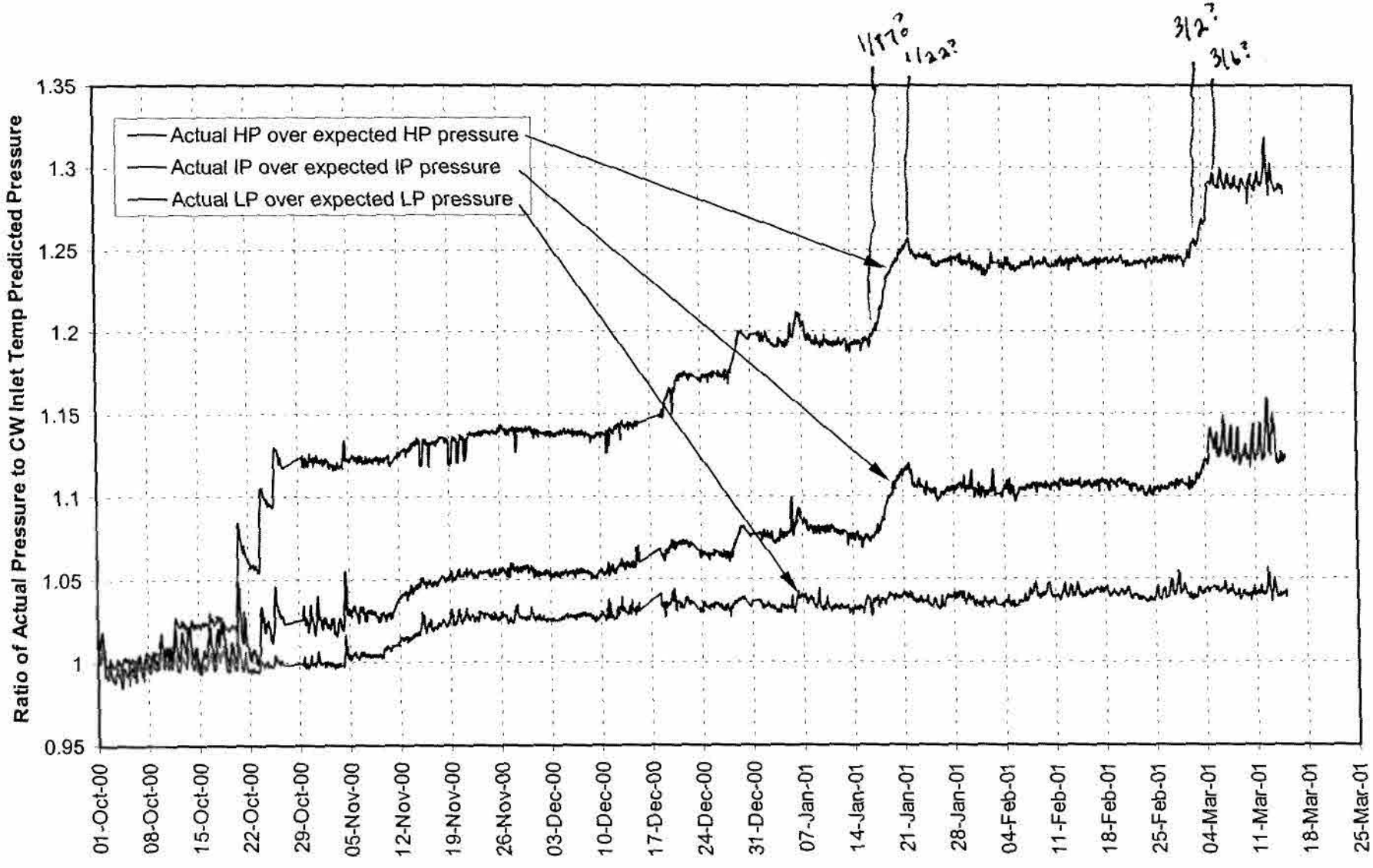


Power losses for the week ending at midnight on 3/13/2001

Date	Description of Cause of Loss	MW-hrs Lost during week	Planned Capability Loss	Unplanned Capability Loss	Unplanned Pwr Change >20%
Current week	CW-FN-6 OOS and decked over. Accumulated losses about 1735 MW-hrs.	65	No	No	No
Current week	Main condenser heat transfer degradation. Accumulated losses about 21150 MW-hrs.	1680	No	Yes	No
Current week	Operating at less than 100% power. Average 99.93%	137	No	No	No
Current week	Miscellaneous leaks to the condenser.	3	No	Yes	No
3/9 and 3/10/01	Down power for rod pattern adjustment and turbine valve testing	1059	Yes	No	No
3/13/01	Down power to deal with high SJAE condenser drain temperature caused by high wind conditions	272	No	No	No

If there are questions concerning this data please call Dave Krieg (x4249).

Condenser Degradation Time Line



EN ENERGY NORTHWEST

P.O. Box 968 • Richland, WA • 99352-0968

April 24, 2006

Mr. Sid Morrison, Chairman
Operations, Construction & Safety Committee
Executive Board of Energy Northwest
P.O. Box 968, Mail Drop 1040
Richland, WA 99354

Re: CGS Main Condenser Replacement

Safe, reliable operation of Columbia Generating Station requires high quality human performance and reliable equipment. Balancing investments in people and equipment against safety and cost is an ongoing challenge. Anytime that balance threatens the welfare of our workers or equipment reliability to an unacceptable degree, we need to act. Such is the case today with Columbia's main condenser.

Columbia has historically been plagued by main condenser reliability issues. In 2002, accelerated corrosion identified on our fuel cladding was directly attributed to a chronic condenser leak during the previous operating cycle. Leakage of impure, raw cooling water into the plant's condensate system continues to threaten the long-term integrity of Columbia's reactor internals, including the fuel cladding. Likewise, the admiralty brass material results in our failure to meet EPRI BWR Vessel Internal Protection guidelines. Left unabated, these conditions could manifest themselves in failure of key reactor components presenting a serious challenge to safe operation of the plant.

Equally as challenging to our daily operations is the increasing deterioration of the condenser tubes themselves. Made of soft admiralty brass, the tubes are especially vulnerable to debris in the circulating water system, which is a raw water system and open to the environment. In short, debris within the circulating water system can be reduced, but not eliminated. This challenge is not unique to Columbia.

Radiological safety and electrical generation have also been adversely impacted by poor main condenser performance. Leakage in the main condenser triggered one forced shutdown and five separate power reductions in the last three years alone. Station personnel received an additional 12 person-rem of dose while performing on-line tube repairs following those incidents. The additional dose will impact our short and long-term dose goals and likely be identified as an "Area for Improvement" when the Institute of Nuclear Power Operations evaluates Columbia in December 2006.

While safety and reliability drive many of our decisions, we cannot lose sight of the tremendous economic impact of poor condenser performance. Loss of generation from

tube leaks since 2003 is approximately $12 million above and beyond the costs of leak repairs and chemical clean-up of the condensate system. Nor does it account for the potential long-term costs associated with replacement of degraded vessel internals or fuel pin leaks.

Our commitment to operating Columbia safely and efficiently is unwavering. However, the challenges presented by our aging condenser system must be addressed if we are to continue operating safely throughout our current license period and beyond.

Safety and reliability have always been top priorities for Columbia. I urge you to continue that standard by obtaining the resources necessary to fully address Columbia's main condenser problems. Anything less needlessly compromises worker safety, plant reliability, cost of power, and potential for license extension.

Sincerely,

Cheryl Whitcomb

Cheryl M. Whitcomb, Chair
Corporate Nuclear Safety Review Board

cc: Executive Board of Energy Northwest
JV Parrish (1023)
CMW/lb

Deep Bed Demineralizers/Retube with Copper

One option that has been considered is to re-tube the condenser with a similar copper based material that is currently installed and then adding deep bed demineralizers in the process stream to remove copper. While this is an alternative, it comes with a number of disadvantages.

Material Issues:

The availability of the original alloy is poor. Currently any orders of this size will be made by non domestic suppliers. The 1-14" tube size options are supplied from India and China. The tube alloys may be from reclaimed copper alloys with increased uncertainty on the quality and condition of the alloys.

Re- tubing with the original alloy is possible. However, testing for joint strength and pullout load is necessary to determine quality of the joint achieved and the necessary modifications of the tube sheet to achieve the joint strength. The re-use of the current alloy does not address the issues of steam side erosion of the soft alloy and the degradation mechanisms that have impacted the life on the current installed tube material.

The sensitivity of the alloy with respect to the processing can adversely impact the tube life. For example; the de-zincification pitting observed in the current tubing is process heat related believed to linked to a combination of tube surface cleanliness and tramp lead in the alloy. This alloy was intentionally stabilized to prevent this attack. The most susceptible tubes have been plugged. The replacement tube must be stabilized and some testing to "qualify" each heat of material against this type of attract will be necessary.

The stress corrosion cracking experienced is a function of the residual stress linked to processing and installation tube damage (denting and Scratches). For the re tubing the damage cannot be completely avoided and therefore this mechanism will not be eliminated by the re tube. The distribution and significance of the SCC will depend on the quality of the tube material and the quality of the installation. Once again, testing and qualification of each heat is necessary to insure maximum SCC resistance. Regardless of the testing, long term SCC leakage should be expected.

If a re-tube is considered an alternate material should be used such as a copper based alloy e.g. aluminum bronze or a 90-10 Cu-Ni alloy. Further review with respect to the install and mechanical joint quality will also be needed for these alloys. Steam erosion will still be a concern and depending on the alloy choice some loss of efficiency can be expected. SCC resistance is dependent on the alloy processing and type.

All of the copper based alloys that are candidates for a re-tube have potential processing related issues. These materials perform well, however; ideal water chemistry conditions and outage tube cleaning is mandatory. There is no design corrosion margin for off normal conditions.

Of particular note is that one adverse event can greatly reduce the tube corrosion life. The resistance to any off normal conditions is dependent on the specific alloy processing variables and installation damage.

Equipment Requirements

Significant capital equipment would have to be installed. Adding deep bed demineralizers would add a significant amount of equipment that would have to be installed and operated for the life of the plant. There is currently no place on site that could easily be converted to an area where deep beds could be installed. As such an entire new facility would have to be built. While it has not been studied in detail, costs in the area of $20-$30 million are likely for the addition of deep beds only. There would still be the costs for the re-tube effort as well.

Original Design

The inherent design flaws of the original condenser design would still be in place. As a consequence no gain in thermal performance (other than recovered tubes) would be realized. Additionally some of the other key advantages of modular would also not be realized such as; Welded tube/tubesheet interface, higher resistance to corrosion and higher resistance to debris.

On-going O&M Costs

While the overall use of resin would be expected to decrease (deep beds can last significantly longer than CFD's) the deep beds, if contaminated by tube leakage or a variety of other issues that can affect deep bed performance, have a substantial disposal cost associated with them. This can lead to a substantial O&M financial hit that is not planned. The net gain/loss comparison would have to studied much further with respect to resin usage. The ongoing costs of maintaining a deep bed system would also have to be factored in. This analysis is unable to draw conclusion in this area but points out the issue.

Conclusion

Given the variety of negative issues associated with this approach, along with its substantial costs, the addition of deep bed demineralizers concurrent with a re-tube effort with a copper based material is not considered a viable option.

ENERGY NORTHWEST

INTEROFFICE MEMO

DATE: October 14, 2008

TO: Steer Committee Members

FROM: Supply Chain Services Manager

SUBJECT: Requests for Proposals 651803 and 651804

CONFLICTS OF INTEREST CERTIFICATE

I certify that I am not aware of any matter which might reduce my ability to participate in the steering committee proceedings and activities in an objective and unbiased manner or which might place me in a position of real or apparent conflict between my responsibilities as a member of the committee and other interests.

In making this certification, I have considered all my stocks, bonds, other financial interests, and employment arrangements (past, present, or under consideration) and, to the extent known by me, all the financial interests and employment arrangements of my spouse or other members of my immediate household.

If, after the date of this certification, any person, firm, or organization with which, to my knowledge, I (including my spouse and other members of my immediate household) have a financial interests, or with which I have (or had) an employment arrangement, submits a proposal or otherwise becomes involved in the subject project, I will notify the chairperson of this committee, and thereafter, until advised to the contrary, I will not participate further in any way (by rendering advice, making recommendations, voting, or otherwise) in the work of this panel.

CONFIDENTIALITY CERTIFICATE

In anticipation of my participation in the steering committee formed to evaluate the proposals submitted in response to the request for proposals for this acquisition, I certify that I will not disclose, except pursuant to the order of a court of competent jurisdiction, any information either during the proceedings of the source evaluation or at any subsequent time, any information concerning the evaluation, to anyone who is not also authorized access to the information by law or regulation, and then only to the extent that

such information is required in connection with such person's official responsibilities. Furthermore, I will report to the chairperson any communication concerning the procurement or the committee's composition and activities directed to me from any source outside the committee.

Signature O/S by AJR

Name _____

Date 10/14/08

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PER RESOLUTION

PER No. 204-0811 REV No. 0

Quality Assessments Initiated ☐ Yes

Followup Assessment of Operability	☐ Yes	☒ NA
Permanent Equipment Disposition Classifications	☐ Permanent Accept-As-Is ☐ Permanent Repair ☐ Rework	☒ NA
Equipment Classification: Quality Class:	☐ 1 ☐ A ☒ 2 ☐ G ☐ Safety Related ☐ ASME	☐ NA
Previous problems or generic impact discussed	☒ Yes	☐ NA

Significant: ☐ Yes ☒ No | Number of interim Corrective Actions: 0 | Number of permanent Corrective Actions: 11

Cause Determination Codes

☐ No Cause Necessary ☐ Unknown (UNKN), Justify in comments ☐ Assumed Risk (AR01), Justify in comments

DESCRIPTION	ORG	PROC	KEY	O&P	HE/IA	GEMS
Inappropriate Action: Plant downpower (60%) required to repair main condenser tube leak on-line resulted in a generation loss of approximately 18000 MWhrs	MUL	FM1	FM	P-2		

Comments:

Management Summary:

Event

On May 25, 2004, Operations manually reduced power to approximately 60% per OI-34 to support on-line main condenser tube plugging in accordance with PPM 8.3.312. Management decided to plug the main condenser tube leak because reactor water chemistry exceeded limits established in SWP-CHE-02 for protecting reactor vessel internals.

Problem

A condenser tube leak required a plant down power to repair the leak on line. This down power resulted in lost generation of approximately 18,000 MWhrs.

Conclusions

The physical cause of the tube leak is indeterminate pending results of the failure analysis for the leaking section of main condenser tube. The leaking tube section will be removed for failure analysis during refueling outage R-17. These actions are identified and tracked under Work Order (WO) 01073375. This cause determination provides a qualitative risk assessment for main condenser tube leaks resulting from foreign material in the CWS, identifies corrective actions to reduce these risks, and identifies fundamental causes for failure of foreign material exclusion controls and for failure of corrective actions from previous occurrences to prevent recurrence.

Root Causes

+ Widespread lack of regard for, or awareness of, importance for foreign material exclusion controls in the CWS across the organization indicating a lack of commitment to FME program implementation.

+ Ineffective corrective actions for previously identified foreign material problems.

+ Lack of appropriate foreign material controls in the CWS (i.e., widespread use of wire ties without regard to the consequence of their use).

Significance

The event had no adverse impact on nuclear safety. Reactor water chemistry guidelines remained within established limits. The online tube plugging effort involves work conditions that increase industrial safety risks for the duration of the task. Equipment and personnel performed as planned during the down power and tube plugging evolution. The event resulted in approximately 18,000 MWhrs loss generation. Main condenser tube leaks caused by flow induced fretting wear or erosion from debris in the condenser have occurred at least seven times in the past. In addition, foreign material in the CWS has created a condition of constant near misses. Debris that could cause main condenser tube leaks have been discovered in the

Approvals For Permanent Disposition

PER Dispositioner	*HUMMER, M*	*07/23/04*
Dispositioning Manager	*TWOMEY, JD*	*07/23/04*

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PER RESOLUTION

PER No. 204-0811 REV No. 0
Quality Assessments Initiated ☐ Yes

water boxes upon every entry since initial plant startup. At least 25 tubes were plugged during R12 because of accumulated damage to the inside diameter of tube from flow induced fretting or erosion from foreign material since initial plant startup. Statistical analysis of this occurrence history indicates an average of 509 days between main condenser tube leak events that requires plant shut down or down power for repairs (or a mean time between failure of 470 days).

Principal Corrective Actions

1. Eliminate the sources of foreign materials that are dominant contributors to risk of main condenser tube leaks.
2. Evaluate the need for physical barriers that provide effective protection against foreign material sources that cannot be reasonably eliminated. Based on results from this evaluation, implement additional and/or enhanced barriers to reduce the risk of tube leaks from foreign materials to acceptable levels.
3. Develop and implement strict program and administrative controls for foreign material exclusion from the CWS and main condenser water boxes.
4. Provide clear signage that communicates a strong message supporting foreign material exclusion controls at all locations (permanent and temporary) that present openings to the CWS and main condenser water boxes.
5. Communicate the consequences and significance of main condenser tube leaks especially those caused by foreign material in the CWS, the corrective actions taken, and roles and responsibilities of all personnel for preventing foreign material from entering the CWS.
6. Assign roles and responsibilities for developing and implementing appropriate practices to ensure foreign material discoveries in the CWS and main condenser capture reasonably available information.
7. Emphasize the expectation for using the condition reporting process to record foreign material discoveries when accessing main condenser water boxes. This is necessary to support subsequent assessment of the effectiveness of the foreign material exclusion controls and to implement appropriate corrective actions.
8. Assess the effectiveness of corrective actions to prevent recurrence during a CWS or refueling outage whichever occurs first.

Description of the Event (or Issue):

A. Time Line Sequence

On 5/19/04 at 03:51, with the reactor operating at 100% power, an increase in the reactor water sulfate level and main condenser hot well sulfate level was noticed. CR 2-04-02341 was generated to document this condition. The shift manager and STA were informed and follow-up sampling was performed. The main condenser leak was confirmed and calculated to be approximately 53 mL/min per CI-11.7 at 13:12.

Chemistry Management established decision points per PPM 1.3.67 at 15:30.

1. If the leak rate exceeds 150 mL/min, NDE should be contacted to perform SF6 testing to identify the leaking water box.
2. If the leak rate reaches 300 mL/min, plans should be made to downpower, find and repair the leak.

From 5/20/04 to 5/22/04 the leak rate trended upwards to about 160 mL/min. Preparations were being made by NDE to perform a SF6 test to establish the leaking water box. The test equipment was being delivered via FedEx because it was off site for repair and calibration. Preparations were also being made by maintenance and engineering to perform on-line tube plugging.

On 5/23/04 at 13:15 the leak rate reached 302 mL/min, exceeding decision point 2. The Shift Manager made a MANS notification due to the increased leak rate on 5/23/04 at 14:32.

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Quality Assessments Initiated ☐ Yes

By 5/24/04 the leak rate had increased to about 418 mL/min, and NDE leak location testing had commenced. On 5/24/04 at 21:45 NDE determined the leak was in the "C" water box, and Chemistry had determined the leak rate to be about 431 mL/min.

The down power to 60% power was commenced on 5/25/04 at 00:55 and completed on 5/25/04 at 05:00. From that time until 5/26/04 at 02:36, the "C" water box was isolated, and the leaking tube was located and plugged.

From 5/26/04 02:36 to 5/26/04 11:27 the "C" water box was placed back on service and the ascension to 100% power was commenced. The reactor was returned to 100% power on 5/26/04 at 21:54. The leak did not return.

Attachment A provides the Detailed Timeline of Events for May 2004 Tube Leak.

B. Additional Background Information

Foreign material can enter Columbia's Circulating Water System (CWS) from a variety of sources as shown in the simplified system schematic of Figure 1. Foreign material of a critical size, shape, and hardness in the CWS flow can get caught at main condenser inlet tube sheets number 1 and 3 and cause a tube leak.

Features and conditions of Columbia's Circulating Water System that increase sensitivity to main condenser tube leaks caused by foreign material (i.e., differences between Columbia and other nuclear power plants) include:

+ Use of wire ties to secure fill in the cooling towers
+ Casual use of wire ties for a variety of tasks (where other methods might be more appropriate)
+ Demineralizers with lower leak handling capacity than those plants with deep bed demineralizers
+ Use of closed loop cooling system, which recirculates the debris (not a once through design)
+ Inability to back flush the condenser
+ Lack of a comprehensive FME implementation in the circulating water basin and cooling tower areas
+ Admiralty Brass and 70-30 Copper Nickel alloy tubing (i.e., softer than most other materials and therefore less resistant to abrasion/erosion)

Types of foreign material historically discovered in the waterside of the Circulating Water System are listed below by relative frequency of observation. The qualitative likelihood of these foreign materials causing a main condenser tube leak is indicated in parenthesis. Likelihood is a subjective estimate based on previous main condenser tube leak occurrences, previously observed damage, and the critical size, shape, and hardness of the foreign material.

21 items

+ Tumbleweeds (minor)
+ Duct tape (minor)
+ Boundary tape (minor)
+ Pieces of ceramic fill (moderate)
+ Tower Fill clips (moderate)
+ Tower Keepers T's (two piece part) (moderate)
+ 7½ Wire tie pieces - Typically clipped (severe)
+ 8½ Wire ties (unused) (severe)
+ Tower Drain (Spray?) nozzles (minor)
+ 10½ Metal Wire - Light gauge sizes (severe)
+ Scaffolding Wire (moderate)

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+ Animal bones (birds/rabbits) (minor)
+ Foam chinking (minor)
+ Various types of plastic bags (minor)
+ Paper trash (minor)
+ Pieces of gaskets (minor)
+ Duck or waterfowl bill (minor)
+ Sand and gravel (minor)
+ Ball peen hammer (minor)
+ Flashlight (minor)
+ Tape measure (minor)

Figure 1 Circulating Water System Simplified Diagram Indicating Foreign Material Sources (see hard copy).

Extent of Condition

A. Scope

The extent of condition evaluation considers other similar components that might experience tube leaks due to damage from debris and would require a plant downpower or shutdown for repair. Assessing the potential for foreign material damage to rotating equipment, major electrical equipment, or instrumentation and control equipment is outside the scope of this root cause analysis. PER 203-2050 (see PERAs 203-2050-02 and -07) involve performing a current assessment of and implementing appropriate enhancements to Columbia's overall foreign material exclusion controls. Other plant components that have internal tube bundles include the feedwater heaters (FWHs), moisture separator reheaters (MSRs) and numerous heat exchangers. Further evaluation of these components is outside the scope of this root cause analysis for the following reasons.

1. The MSRs and FHWs as these components route "closed" systems (COND, MS, BS, etc.) through their tubes as opposed to the condenser that uses an "open" system (CW).
2. When maintenance activities are being performed inside these components foreign material exclusion (FME) is maintained per our site procedures.
3. Historical data that reveals damage to these components from foreign material has been limited to 1-2 tubes in a feedwater heater from a bolt.
4. A tube leak in any heat exchanger does not have the same potential consequences (damage to vessel internals) as a tube leak in the main condenser due to the chemistry in the circulating water system.

The scope of this root cause analysis is also limited to tube leaks caused by fretting wear or erosion from debris on the water side of the condenser. Assessing the potential for damage to main condenser tubes from other mechanisms that could result in a tube leak and require a plant down power or shutdown for repair is outside the scope of this root cause analysis for the following reasons.

1. The cause of the damage to the condenser tube and resulting leak is most likely due to debris induced fretting or localized flow erosion of the tube in the condenser waterbox.
2. Damage due to steam impingement usually occurs quickly once the tube is exposed to the steam and is limited to outer or peripheral tubes where the condenser penetrations are located. There were no known steam leaks into the condenser at the time as detected by thermal performance evaluation before and during the time period when the condenser leak was identified. The leaking tube was not a peripheral tube that could have been exposed to steam erosion. The tube was located near the center of the tube bundle (C1 top tube sheet, upper right quadrant Row 24 tube 4).
3. Tube damage due to long-term flow induced erosion has different characteristics than that of debris induced fretting or debris induced short-term localized erosion. Long-term flow induced erosion is addressed by eddy current testing performed on the condenser tubes during refueling outages.

Condenser Retube Study

Whatif Modular Options Moved to FY11

Project Manager: Joe Frisco
Prepared 1-29-07 CJI

Present Value Results	FY07 $K NPV					
	Base Case	Alt 1	Alt 2	Alt 3	Alt 4	Alt 5
Total Present Value Costs	$ (73,227)	$ (65,433)	$ (70,972)	$ (65,529)	$ (74,912)	$ (89,962)
Sensitivity Analysis						
No fuel failure risk penalties	$ (67,472)	$ (62,459)			$ (71,938)	$ (86,988)

	FY07 $M NPV								
	Installation Costs	Installation Outage Impacts/ Incl Dose	Chem Decon (incl dose)	Fuel Failure Risk	Projected Downpowers for Tube Leaks	Reduced Dose	(Derate)/ Increased Generation	Added ongoing Inspection Costs for Modular	Total
Base Case	$ (24.9)	$ (24.6)	$ (11.7)	$ (5.8)	$ (10.2)	$ 17.5	$ (13.6)	$ -	$ (73.2)
Option 1	$ (49.0)	$ (24.9)	$ (8.0)	$ (3.0)	$ -	$ 19.4	$ -	$ -	$ (65.4)
Option 2	$ (24.0)	$ (32.7)	$ (8.0)	$ -	$ -	$ 19.4	$ (25.6)	$ -	$ (71.0)
Option 3	$ (28.4)	$ (32.7)	$ (8.0)	$ -	$ -	$ 19.4	$ (15.8)	$ -	$ (65.5)
Option 4 FY11	$ (55.3)	$ (85.0)	$ (11.7)	$ (3.0)	$ (5.3)	$ 17.5	$ 69.6	$ (1.8)	$ (74.9)
Option 5 FY11	$ (70.5)	$ (85.0)	$ (11.7)	$ (3.0)	$ (5.3)	$ 17.5	$ 69.6	$ (1.7)	$ (90.0)

Present Value Details - Magnitude and Sensitivity of Input Assumptions

	FY07 $M NPV					
Impact/Description	**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Installation Costs	$ (24.9)	$ (49.0)	$ (24.0)	$ (28.4)	$ (55.3)	$ (70.5)
Installation Outage Impacts/ Incl Dose	$ (24.6)	$ (24.9)	$ (32.7)	$ (32.7)	$ (85.0)	$ (85.0)
Chem Decon (incl dose)	$ (11.7)	$ (8.0)	$ (8.0)	$ (8.0)	$ (11.7)	$ (11.7)
Fuel Failure Risk	$ (5.8)	$ (3.0)	$ -	$ -	$ (3.0)	$ (3.0)
Projected Downpowers for Tube Leaks	$ (10.2)	$ -	$ -	$ -	$ (5.3)	$ (5.3)
Reduced Dose	$ 17.5	$ 19.4	$ 19.4	$ 19.4	$ 17.5	$ 17.5
(Derate)/ Increased Generation	$ (13.6)	$ -	$ (25.6)	$ (15.8)	$ 69.6	$ 69.6
Added ongoing Inspection Costs for Modular	$ -	$ -	$ -	$ -	$ (1.8)	$ (1.7)
Total	**$ (73.2)**	**$ (65.4)**	**$ (71.0)**	**$ (65.5)**	**$ (74.9)**	**$ (90.0)**

PHC Project Ranking	**16**
Project Type	**Capital**

Summary Cost Estimate

	FY07 $K					
	Base Case	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Current Estimated Capital Costs	$ 30,586	$ 54,512	$ 25,897	$ 30,586	$ 63,493	$ 80,933

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Options Considered

Base Case - Delay condenser retube approximately 6 years to FY13 and then use Alternative 3
Option 1 - Retube with copper in FY09 and install deep-bed deminerlizers in FY11
Option 2 - Retube with stainless steel (Sea-Cure) in FY09
Option 3 - Retube with titanium in FY09
Option 4 - Retube with modular stainless steel bundles (Sea-Cure) in FY11
Option 5 - Retube with modular titanium bundles in FY11
Option 6 - Retube over 2 outages with titanium - not considered viable due to 1) outage penalties would double, 2) thermal expansion differences from different materials

Recommended Option

Option 3 - Retube with titanium in FY09

COST BENEFIT ANALYSIS

Key Assumptions/Qualifications

Note: All alternatives will result in condenser retube

Discount Rate		6.5%
Escalation		3.0%
Man-rem exposure costs $K/man-rem	$	25
FY09 Outage w/o Condenser (days)		35

ESTIMATED COSTS BREAKDOWN

		FY07 $K					
		Base Case	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Capital Costs by Work							
Retube Condenser/Includes Disposal Costs		$ 28,061	$ 25,011	$ 23,759	$ 28,061	$ 58,250	$ 74,250
Deep Bed Demin		$ -	$ 25,000	$ -	$ -	$ -	$ -
Sales and Use Tax	9%	$ 2,525	$ 4,501	$ 2,138	$ 2,525	$ 5,243	$ 6,683
Total Capital Costs		$ 30,586	$ 54,512	$ 25,897	$ 30,586	$ 63,493	$ 80,933

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Capital Costs Flow	FY07 $K					
	Base Case	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
FY07						
FY08	$ -	$ 500	$ 500	$ 500	$ -	$ -
FY09	$ -	$ 20,000	$ 18,000	$ 23,000	$ -	$ -
FY10	$ -	$ 5,000	$ 7,397	$ 7,086	$ 500	$ 500
FY11	$ -	$ 25,000			$ 53,000	$ 69,000
FY12	$ 500	$ 4,012			$ 9,993	$ 11,433
FY13	$ 23,000					
FY14	$ 7,086					
FY15						
FY16						
Total	$ 30,586	$ 54,512	$ 25,897	$ 30,586	$ 63,493	$ 80,933

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Capital Costs by Expense Class	FY07 $K Alt 3
ENW labor Manual and non-manual	$ 3,500
Material	$ 10,943
Installation contract	$ 10,118
Decon/Disposal	$ 3,500
Sale and Use tax	$ 2,525
Total	$ 30,586

		FY07 $K					
Other Cost Impacts Assumptions		**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Radiation							
Radiation Impacts Retubing (man-rems)		12	12	12	12	60	60
Cost per Man-rem (FY07$K)		$ 25	$ 25	$ 25	$ 25	$ 25	$ 25
Total Radiation Impacts (FY07$K)		$ 300	$ 300	$ 300	$ 300	$ 1,500	$ 1,500
Installation Outage Impacts							
Incremental Outage Impact (Days)		33	25	33	33	85	85
Lost MWH from Outage Impact	1107	876,744	664,200	876,744	876,744	2,258,280	2,258,280
Annual Derate/Increase							
Lost MWH from Summer Derate		17,133	-	27,818	17,133	-	-
Increased Generation (MWH)						91,542	91,542
Additional Annual Inspection Costs							
Per Outage (FY07$K)		$ -	$ -	$ -	$ -	$ 220	$ 200
Chemical Decon		$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367
Radiation Impacts from Decon (man-rems)		15	15	15	15	15	15
Radiation Benefits for Copper Removal							
Man-rems Saved		50	50	50	50	50	50
Value of Man-rems saved (FY07 $K)		$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250
Fuel Failure Risk from copper							
Probability of failure Annually							
prior to retube post FY09		0.05	0.05			0.05	0.05
Cost of a failure							
Direct Cost (FY07$K)		$ 4,000	$ 4,000			$ 4,000	$ 4,000
Fuel Purchase (FY07$K)		$ 25,000	$ 25,000			$ 25,000	$ 25,000
Root Cause Analysis (FY07$K)		$ 4,000	$ 4,000			$ 4,000	$ 4,000
Radiation Costs of a failure (FY07$K)		$ 425	$ 425			$ 425	$ 425
Total Fuel Failure Costs (FY07$K)		$ 33,425	$ 33,425			$ 33,425	$ 33,425
Annualized Cost for Fuel Failure Risk (FY07$K)		$ 1,671	$ 1,671			$ 1,671	$ 1,671
Downpowers for Condenser Problems Post FY09							
Direct Costs (FY07$K)		$ 605				$ 605	$ 605
Annual Average Lost Generatic	40	$ 2,358	Based upon 6 in the last 3 years due to			$ 2,358	$ 2,358
Total Downpowers Loss and Cost (FY07$K)		$ 2,963	condenser tube leaks			$ 2,963	$ 2,963

Total Lost MWH	No. of Downpowers	Ave Lost MWH/Dwn
176881	6	29480.16667

Base Case													
	Discount	Escalation	Capital Costs	Installation Retube Radiation Impacts	Installation Outage Impacts	Decon Costs	Radiation Impact From Decon	Downpowers Due to Condenser Problems	Summer Derate	Added Inspection Costs Post retube	Fuel Failure Annual Incremental Risk Premium	Benefit of reduced man-rems	Present Value
FY07	1.0000	1.0000	$ -	$ -	$ -				$ -	$ -			$ -
FY08	0.9390	1.0300	$ -	$ -	$ -				$ -	$ -			$ -
FY09	0.8817	1.0609	$ -	$ -	$ -	$ -			$ -	$ -			$ -
FY10	0.8278	1.0927	$ -	$ -	$ -	$ -		$ (2,681)	$ -	$ -	$ (1,512)		$ (4,193)
FY11	0.7773	1.1255	$ -	$ -	$ -	$ (3,821)	$ (328)	$ (2,593)	$ -	$ -	$ (1,462)		$ (8,203)
FY12	0.7299	1.1593	$ (423)	$ -	$ -	$ -		$ (2,507)	$ -	$ -	$ (1,414)		$ (4,345)
FY13	0.6853	1.1941	$ (18,821)	$ (245)	$ (24,385)	$ (3,574)	$ (307)	$ (2,425)	$ -	$ -	$ (1,368)		$ (51,125)
FY14	0.6435	1.2299	$ (5,608)	$ -	$ -	$ -			$ (750)	$ -			$ (6,358)
FY15	0.6042	1.2668	$ -	$ -	$ -	$ (3,343)	$ (287)		$ (683)	$ -			$ (4,313)
FY16	0.5674	1.3048	$ -	$ -	$ -				$ (585)	$ -		$ 925	$ 341
FY17	0.5327	1.3439	$ -	$ -	$ -				$ (547)	$ -		$ 895	$ 348
FY18	0.5002	1.3842	$ -	$ -	$ -				$ (575)	$ -		$ 866	$ 291
FY19	0.4697	1.4258	$ -	$ -	$ -				$ (592)	$ -		$ 837	$ 245
FY20	0.4410	1.4685	$ -	$ -	$ -				$ (573)	$ -		$ 810	$ 237
FY21	0.4141	1.5126	$ -	$ -	$ -				$ (554)	$ -		$ 783	$ 229
FY22	0.3888	1.5580	$ -	$ -					$ (536)	$ -		$ 757	$ 222
FY23	0.3651	1.6047	$ -	$ -	$ -				$ (518)	$ -		$ 732	$ 214
FY24	0.3428	1.6528	$ -	$ -	$ -				$ (501)	$ -		$ 708	$ 207
FY25	0.3219	1.7024							$ (484)			$ 685	$ 201
FY26	0.3022	1.7535							$ (469)			$ 662	$ 194
FY27	0.2838	1.8061							$ (453)			$ 641	$ 188
FY28	0.2665	1.8603							$ (438)			$ 620	$ 181
FY29	0.2502	1.9161							$ (424)			$ 599	$ 175
FY30	0.2349	1.9736							$ (410)			$ 580	$ 170
FY31	0.2206	2.0328							$ (396)			$ 561	$ 164
FY32	0.2071	2.0938							$ (383)			$ 542	$ 159
FY33	0.1945	2.1566							$ (371)			$ 524	$ 153
FY34	0.1826	2.2213							$ (359)			$ 507	$ 148
FY35	0.1715	2.2879							$ (347)			$ 490	$ 144
FY36	0.1610	2.3566							$ (335)			$ 474	$ 139
FY37	0.1512	2.4273							$ (324)			$ 459	$ 134
FY38	0.1420	2.5001							$ (314)			$ 444	$ 130
FY39	0.1333	2.5751							$ (303)			$ 429	$ 126
FY40	0.1252	2.6523							$ (293)			$ 415	$ 121
FY41	0.1175	2.7319							$ (284)			$ 401	$ 117
FY42	0.1103	2.8139							$ (275)			$ 388	$ 114
FY43	0.1036	2.8983							$ (265)			$ 375	$ 110
FY44	0.0973	2.9852							$ (257)			$ 363	$ 106
Total			$ (24,853)	$ (245)	$ (24,385)	$ (10,737)	$ (922)	$ (10,206)	$ (13,597)	$ -	$ (5,756)	$ 17,473	$ (73,227)

Alternative 1												
	Discount	Escalation	Capital Costs	Installation Retube Radiation Impacts	Installation Outage Impacts	Decon Costs	Radiation Impact From Decon	Summer Derate	Added Inspection Costs Post retube	Fuel Failure Annual Incremental Risk Premium	Benefit of reduced man-rems	Present Value
FY07	1.0000	1.0000	$ -	$ -	$ -			$ -	$ -			$ -
FY08	0.9390	1.0300	$ (484)	$ -	$ -			$ -	$ -			$ (484)
FY09	0.8817	1.0609	$ (18,707)	$ (281)	$ (24,587)	$ -		$ -	$ -			$ (43,575)
FY10	0.8278	1.0927	$ (4,523)			$ -		$ -	$ -	$ (1,512)		$ (6,035)
FY11	0.7773	1.1255	$ (21,872)			$ (3,821)	$ (328)	$ -	$ -	$ (1,462)		$ (27,483)
FY12	0.7299	1.1593	$ (3,395)					$ -	$ -	$ -		$ (3,395)
FY13	0.6853	1.1941	$ -			$ (3,574)	$ (307)	$ -	$ -	$ -		$ (3,880)
FY14	0.6435	1.2299	$ -			$ -		$ -	$ -		$ 989	$ 989
FY15	0.6042	1.2668	$ -					$ -	$ -		$ 957	$ 957
FY16	0.5674	1.3048	$ -					$ -	$ -		$ 925	$ 925
FY17	0.5327	1.3439	$ -					$ -	$ -		$ 895	$ 895
FY18	0.5002	1.3842	$ -					$ -	$ -		$ 866	$ 866
FY19	0.4697	1.4258	$ -					$ -	$ -		$ 837	$ 837
FY20	0.4410	1.4685	$ -					$ -	$ -		$ 810	$ 810
FY21	0.4141	1.5126	$ -					$ -	$ -		$ 783	$ 783
FY22	0.3888	1.5580	$ -					$ -	$ -		$ 757	$ 757
FY23	0.3651	1.6047	$ -					$ -	$ -		$ 732	$ 732
FY24	0.3428	1.6528	$ -					$ -	$ -		$ 708	$ 708
FY25	0.3219	1.7024									$ 685	$ 685
FY26	0.3022	1.7535									$ 662	$ 662
FY27	0.2838	1.8061									$ 641	$ 641
FY28	0.2665	1.8603									$ 620	$ 620
FY29	0.2502	1.9161									$ 599	$ 599
FY30	0.2349	1.9736									$ 580	$ 580
FY31	0.2206	2.0328									$ 561	$ 561
FY32	0.2071	2.0938									$ 542	$ 542
FY33	0.1945	2.1566									$ 524	$ 524
FY34	0.1826	2.2213									$ 507	$ 507
FY35	0.1715	2.2879									$ 490	$ 490
FY36	0.1610	2.3566									$ 474	$ 474
FY37	0.1512	2.4273									$ 459	$ 459
FY38	0.1420	2.5001									$ 444	$ 444
FY39	0.1333	2.5751									$ 429	$ 429
FY40	0.1252	2.6523									$ 415	$ 415
FY41	0.1175	2.7319									$ 401	$ 401
FY42	0.1103	2.8139									$ 388	$ 388
FY43	0.1036	2.8983									$ 375	$ 375
FY44	0.0973	2.9852									$ 363	$ 363
Total			$ (48,980)	$ (281)	$ (24,587)	$ (7,394)	$ (635)	$ -	$ -	$ (2,974)	$ 19,419	$ (65,433)

Alternative 2											
	Discount	Escalation	Capital Costs	Installation Retube Radiation Impacts	Installation Outage Impacts	Decon Costs	Radiation Impact From Decon	Summer Derate	Added Inspection Costs Post retube	Benefit of reduced man-rems	Present Value
FY07	1.0000	1.0000	$ -	$ -	$ -			$ -	$ -		$ -
FY08	0.9390	1.0300	$ (484)	$ -	$ -			$ -	$ -		$ (484)
FY09	0.8817	1.0609	$ (16,836)	$ (281)	$ (32,455)	$ -		$ -	$ -		$ (49,572)
FY10	0.8278	1.0927	$ (6,691)			$ -		$ (1,319)	$ -		$ (8,010)
FY11	0.7773	1.1255	$ -			$ (3,821)	$ (328)	$ (1,199)	$ -		$ (5,348)
FY12	0.7299	1.1593	$ -					$ (1,047)	$ -		$ (1,047)
FY13	0.6853	1.1941	$ -			$ (3,574)	$ (307)	$ (990)	$ -		$ (4,871)
FY14	0.6435	1.2299	$ -			$ -		$ (1,021)	$ -	$ 989	$ (31)
FY15	0.6042	1.2668	$ -					$ (1,040)	$ -	$ 957	$ (84)
FY16	0.5674	1.3048	$ -					$ (1,006)	$ -	$ 925	$ (81)
FY17	0.5327	1.3439	$ -					$ (973)	$ -	$ 895	$ (78)
FY18	0.5002	1.3842	$ -					$ (941)	$ -	$ 866	$ (76)
FY19	0.4697	1.4258	$ -					$ (910)	$ -	$ 837	$ (73)
FY20	0.4410	1.4685	$ -					$ (880)	$ -	$ 810	$ (71)
FY21	0.4141	1.5126	$ -					$ (851)	$ -	$ 783	$ (68)
FY22	0.3888	1.5580	$ -					$ (823)	$ -	$ 757	$ (66)
FY23	0.3651	1.6047	$ -					$ (796)	$ -	$ 732	$ (64)
FY24	0.3428	1.6528	$ -					$ (770)	$ -	$ 708	$ (62)
FY25	0.3219	1.7024						$ (745)	$ -	$ 685	$ (60)
FY26	0.3022	1.7535						$ (720)	$ -	$ 662	$ (58)
FY27	0.2838	1.8061						$ (697)	$ -	$ 641	$ (56)
FY28	0.2665	1.8603						$ (674)	$ -	$ 620	$ (54)
FY29	0.2502	1.9161						$ (652)	$ -	$ 599	$ (52)
FY30	0.2349	1.9736						$ (630)	$ -	$ 580	$ (51)
FY31	0.2206	2.0328						$ (610)	$ -	$ 561	$ (49)
FY32	0.2071	2.0938						$ (589)	$ -	$ 542	$ (47)
FY33	0.1945	2.1566						$ (570)	$ -	$ 524	$ (46)
FY34	0.1826	2.2213						$ (551)	$ -	$ 507	$ (44)
FY35	0.1715	2.2879						$ (533)	$ -	$ 490	$ (43)
FY36	0.1610	2.3566						$ (516)	$ -	$ 474	$ (41)
FY37	0.1512	2.4273						$ (499)	$ -	$ 459	$ (40)
FY38	0.1420	2.5001						$ (482)	$ -	$ 444	$ (39)
FY39	0.1333	2.5751						$ (467)	$ -	$ 429	$ (37)
FY40	0.1252	2.6523						$ (451)	$ -	$ 415	$ (36)
FY41	0.1175	2.7319						$ (436)	$ -	$ 401	$ (35)
FY42	0.1103	2.8139						$ (422)	$ -	$ 388	$ (34)
FY43	0.1036	2.8983						$ (408)	$ -	$ 375	$ (33)
FY44	0.0973	2.9852						$ (395)	$ -	$ 363	$ (32)
Total			$ (24,011)	$ (281)	$ (32,455)	$ (7,394)	$ (635)	$ (25,615)	$ -	$ 19,419	$ (70,972)

Alternative 3											
	Discount	Escalation	Capital Costs	Installation Retube Radiation Impacts	Installation Outage Impacts	Decon Costs	Radiation Impact From Decon	Summer Derate	Added Inspection Costs Post retube	Benefit of reduced man-rems	Present Value
FY07	1.0000	1.0000	$ -	$ -	$ -			$ -	$ -		$ -
FY08	0.9390	1.0300	$ (484)	$ -	$ -			$ -	$ -		$ (484)
FY09	0.8817	1.0609	$ (21,513)	$ (281)	$ (32,455)	$ -		$ -	$ -		$ (54,249)
FY10	0.8278	1.0927	$ (6,410)			$ -		$ (812)	$ -		$ (7,222)
FY11	0.7773	1.1255	$ -			$ (3,821)	$ (328)	$ (738)	$ -		$ (4,887)
FY12	0.7299	1.1593	$ -					$ (645)	$ -		$ (645)
FY13	0.6853	1.1941	$ -			$ (3,574)	$ (307)	$ (610)	$ -		$ (4,490)
FY14	0.6435	1.2299	$ -			$ -		$ (629)	$ -	$ 989	$ 361
FY15	0.6042	1.2668	$ -					$ (641)	$ -	$ 957	$ 316
FY16	0.5674	1.3048	$ -					$ (620)	$ -	$ 925	$ 306
FY17	0.5327	1.3439	$ -					$ (599)	$ -	$ 895	$ 296
FY18	0.5002	1.3842	$ -					$ (580)	$ -	$ 866	$ 286
FY19	0.4697	1.4258	$ -					$ (561)	$ -	$ 837	$ 276
FY20	0.4410	1.4685	$ -					$ (542)	$ -	$ 810	$ 267
FY21	0.4141	1.5126	$ -					$ (524)	$ -	$ 783	$ 259
FY22	0.3888	1.5580	$ -					$ (507)	$ -	$ 757	$ 250
FY23	0.3651	1.6047	$ -					$ (490)	$ -	$ 732	$ 242
FY24	0.3428	1.6528	$ -					$ (474)	$ -	$ 708	$ 234
FY25	0.3219	1.7024						$ (459)	$ -	$ 685	$ 226
FY26	0.3022	1.7535						$ (444)	$ -	$ 662	$ 219
FY27	0.2838	1.8061						$ (429)	$ -	$ 641	$ 212
FY28	0.2665	1.8603						$ (415)	$ -	$ 620	$ 205
FY29	0.2502	1.9161						$ (401)	$ -	$ 599	$ 198
FY30	0.2349	1.9736						$ (388)	$ -	$ 580	$ 191
FY31	0.2206	2.0328						$ (375)	$ -	$ 561	$ 185
FY32	0.2071	2.0938						$ (363)	$ -	$ 542	$ 179
FY33	0.1945	2.1566						$ (351)	$ -	$ 524	$ 173
FY34	0.1826	2.2213						$ (340)	$ -	$ 507	$ 167
FY35	0.1715	2.2879						$ (328)	$ -	$ 490	$ 162
FY36	0.1610	2.3566						$ (318)	$ -	$ 474	$ 157
FY37	0.1512	2.4273						$ (307)	$ -	$ 459	$ 152
FY38	0.1420	2.5001						$ (297)	$ -	$ 444	$ 147
FY39	0.1333	2.5751						$ (287)	$ -	$ 429	$ 142
FY40	0.1252	2.6523						$ (278)	$ -	$ 415	$ 137
FY41	0.1175	2.7319						$ (269)	$ -	$ 401	$ 133
FY42	0.1103	2.8139						$ (260)	$ -	$ 388	$ 128
FY43	0.1036	2.8983						$ (251)	$ -	$ 375	$ 124
FY44	0.0973	2.9852						$ (243)	$ -	$ 363	$ 120
Total			$ (28,407)	$ (281)	$ (32,455)	$ (7,394)	$ (635)	$ (15,776)	$ -	$ 19,419	$ (65,529)

Alternative 4													
	Discount	Escalation	Capital Costs	Installation Retube Radiation Impacts	Installation Outage Impacts	Decon Costs	Radiation Impact From Decon	Increased Generation	Downpowers Due to Condenser Problems	Added Inspection Costs Post retube	Benefit of reduced man-rems	Fuel Failure Annual Incremental Risk Premium	Present Value
FY07	1.0000	1.0000	$ -	$ -	$ -			$ -		$ -			$ -
FY08	0.9390	1.0300	$ -	$ -	$ -			$ -		$ -			$ -
FY09	0.8817	1.0609	$ -	$ (1,403)	$ (83,597)	$ -		$ -		$ -			$(85,000)
FY10	0.8278	1.0927	$ (452)			$ -		$ -	$ (2,681)	$ -		$ (1,512)	$ (4,645)
FY11	0.7773	1.1255	$ (46,369)			$ (3,821)	$ (328)	$ -	$ (2,593)	$ -		$ (1,462)	$(54,572)
FY12	0.7299	1.1593	$ (8,455)					$ 3,213	$ -	$ -		$ -	$ (5,242)
FY13	0.6853	1.1941	$ -			$ (3,574)	$ (307)	$ 3,055	$ -	$ (180)		$ -	$ (1,005)
FY14	0.6435	1.2299	$ -					$ 3,053		$ -	$ -		$ 3,053
FY15	0.6042	1.2668	$ -			$ (3,343)	$ (287)	$ 3,100		$ (168)	$ -		$ (698)
FY16	0.5674	1.3048	$ -					$ 3,030		$ -	$ 925		$ 3,955
FY17	0.5327	1.3439	$ -					$ 2,930		$ (158)	$ 895		$ 3,667
FY18	0.5002	1.3842	$ -					$ 2,834		$ -	$ 866		$ 3,699
FY19	0.4697	1.4258	$ -					$ 2,741		$ (147)	$ 837		$ 3,430
FY20	0.4410	1.4685	$ -					$ 2,651		$ -	$ 810		$ 3,460
FY21	0.4141	1.5126	$ -					$ 2,563		$ (138)	$ 783		$ 3,209
FY22	0.3888	1.5580	$ -					$ 2,479		$ -	$ 757		$ 3,236
FY23	0.3651	1.6047	$ -					$ 2,398		$ (129)	$ 732		$ 3,001
FY24	0.3428	1.6528	$ -					$ 2,319			$ 708		$ 3,027
FY25	0.3219	1.7024						$ 2,243		$ (121)	$ 685		$ 2,807
FY26	0.3022	1.7535						$ 2,169			$ 662		$ 2,831
FY27	0.2838	1.8061						$ 2,098		$ (113)	$ 641		$ 2,626
FY28	0.2665	1.8603						$ 2,029			$ 620		$ 2,648
FY29	0.2502	1.9161						$ 1,962		$ (105)	$ 599		$ 2,456
FY30	0.2349	1.9736						$ 1,898			$ 580		$ 2,477
FY31	0.2206	2.0328						$ 1,835		$ (99)	$ 561		$ 2,297
FY32	0.2071	2.0938						$ 1,775			$ 542		$ 2,317
FY33	0.1945	2.1566						$ 1,717		$ (92)	$ 524		$ 2,149
FY34	0.1826	2.2213						$ 1,660			$ 507		$ 2,167
FY35	0.1715	2.2879						$ 1,606		$ (86)	$ 490		$ 2,010
FY36	0.1610	2.3566						$ 1,553			$ 474		$ 2,027
FY37	0.1512	2.4273						$ 1,502		$ (81)	$ 459		$ 1,880
FY38	0.1420	2.5001						$ 1,452			$ 444		$ 1,896
FY39	0.1333	2.5751						$ 1,405		$ (76)	$ 429		$ 1,758
FY40	0.1252	2.6523						$ 1,359			$ 415		$ 1,774
FY41	0.1175	2.7319						$ 1,314		$ (71)	$ 401		$ 1,645
FY42	0.1103	2.8139						$ 1,271			$ 388		$ 1,659
FY43	0.1036	2.8983						$ 1,229		$ (66)	$ 375		$ 1,538
FY44	0.0973	2.9852						$ 1,189			$ 363		$ 1,552
Total			$ (55,277)	$ (1,403)	$ (83,597)	$ (10,737)	$ (922)	$ 69,627	$ (5,273)	$ (1,829)	$ 17,473	$ (2,974)	$(74,912)

Alternative 5													
	Discount	Escalation	Capital Costs	Installation Retube Radiation Impacts	Installation Outage Impacts	Decon Costs	Radiation Impact From Decon	Increased Generation	Downpowers Due to Condenser Problems	Added Inspection Costs Post retube	Benefit of reduced man-rems	Fuel Failure Annual Incremental Risk Premium	Present Value
FY07	1.0000	1.0000	$ -	$ -	$ -			$ -		$ -			$ -
FY08	0.9390	1.0300	$ -	$ -	$ -			$ -		$ -			$ -
FY09	0.8817	1.0609	$ -	$ (1,403)	$ (83,597)	$ -		$ -		$ -			$ (85,000)
FY10	0.8278	1.0927	$ (452)			$ -		$ -	$ (2,681)	$ -		$ (1,512)	$ (4,645)
FY11	0.7773	1.1255	$ (60,367)			$ (3,821)	$ (328)	$ -	$ (2,593)	$ -		$ (1,462)	$ (68,570)
FY12	0.7299	1.1593	$ (9,674)					$ 3,213	$ -	$ -		$ -	$ (6,461)
FY13	0.6853	1.1941	$ -			$ (3,574)	$ (307)	$ 3,055	$ -	$ (164)		$ -	$ (989)
FY14	0.6435	1.2299	$ -					$ 3,053		$ -	$ -		$ 3,053
FY15	0.6042	1.2668	$ -			$ (3,343)	$ (287)	$ 3,100		$ (153)	$ -		$ (683)
FY16	0.5674	1.3048	$ -					$ 3,030		$ -	$ 925		$ 3,955
FY17	0.5327	1.3439	$ -					$ 2,930		$ (143)	$ 895		$ 3,682
FY18	0.5002	1.3842	$ -					$ 2,834		$ -	$ 866		$ 3,699
FY19	0.4697	1.4258	$ -					$ 2,741		$ (134)	$ 837		$ 3,444
FY20	0.4410	1.4685	$ -					$ 2,651		$ -	$ 810		$ 3,460
FY21	0.4141	1.5126	$ -					$ 2,563		$ (125)	$ 783		$ 3,221
FY22	0.3888	1.5580	$ -					$ 2,479		$ -	$ 757		$ 3,236
FY23	0.3651	1.6047	$ -					$ 2,398		$ (117)	$ 732		$ 3,013
FY24	0.3428	1.6528	$ -					$ 2,319			$ 708		$ 3,027
FY25	0.3219	1.7024						$ 2,243		$ (110)	$ 685		$ 2,818
FY26	0.3022	1.7535						$ 2,169			$ 662		$ 2,831
FY27	0.2838	1.8061						$ 2,098		$ (103)	$ 641		$ 2,636
FY28	0.2665	1.8603						$ 2,029			$ 620		$ 2,648
FY29	0.2502	1.9161						$ 1,962		$ (96)	$ 599		$ 2,465
FY30	0.2349	1.9736						$ 1,898			$ 580		$ 2,477
FY31	0.2206	2.0328						$ 1,835		$ (90)	$ 561		$ 2,306
FY32	0.2071	2.0938						$ 1,775			$ 542		$ 2,317
FY33	0.1945	2.1566						$ 1,717		$ (84)	$ 524		$ 2,157
FY34	0.1826	2.2213						$ 1,660			$ 507		$ 2,167
FY35	0.1715	2.2879						$ 1,606		$ (78)	$ 490		$ 2,018
FY36	0.1610	2.3566						$ 1,553			$ 474		$ 2,027
FY37	0.1512	2.4273						$ 1,502		$ (73)	$ 459		$ 1,887
FY38	0.1420	2.5001						$ 1,452			$ 444		$ 1,896
FY39	0.1333	2.5751						$ 1,405		$ (69)	$ 429		$ 1,765
FY40	0.1252	2.6523						$ 1,359			$ 415		$ 1,774
FY41	0.1175	2.7319						$ 1,314		$ (64)	$ 401		$ 1,651
FY42	0.1103	2.8139						$ 1,271			$ 388		$ 1,659
FY43	0.1036	2.8983						$ 1,229		$ (60)	$ 375		$ 1,544
FY44	0.0973	2.9852						$ 1,189			$ 363		$ 1,552
Total			$ (70,493)	$ (1,403)	$ (83,597)	$ (10,737)	$ (922)	$ 69,627	$ (5,273)	$ (1,663)	$ 17,473	$ (2,974)	$ (89,962)

Mid C Power Forecast
Average Annual $/MWH
Provided by BPA - January 9, 2007

	Outage Impact Price - March - April			Summer Derate Price - August		
	Alt 1	Alt 2	Ave Al t1 &2	Alt 1	Alt 2	Ave Al t1 &2
FY07	38.0	37.0	37.5			
FY08	37.8	45.0	41.4	48.5	63.7	56.1
FY09	36.3	47.6	42.0	47.4	70.5	58.9
FY10	34.8	46.3	40.5	46.5	68.0	57.3
FY11	33.7	44.2	39.0	44.9	66.0	55.4
FY12	35.5	42.0	38.7	43.0	60.1	51.6
FY13	37.2	44.0	40.6	44.0	59.9	51.9
FY14	39.8	49.2	44.5	47.0	67.0	57.0
FY15	42.0	54.0	48.0	50.2	73.6	61.9
FY16	54.4	70.6	62.5	51.7	75.8	63.8
FY17	56.0	72.7	64.4	53.3	78.1	65.7
FY18	57.7	74.9	66.3	54.9	80.4	67.6
FY19	59.4	77.2	68.3	56.5	82.8	69.7
FY20	61.2	79.5	70.3	58.2	85.3	71.8
FY21	63.0	81.9	72.4	60.0	87.8	73.9
FY22	64.9	84.3	74.6	61.8	90.5	76.1
FY23	66.9	86.8	76.8	63.6	93.2	78.4
FY24	68.9	89.4	79.2	65.5	96.0	80.8
FY25	70.9	92.1	81.5	67.5	98.9	83.2
FY26	73.1	94.9	84.0	69.5	101.8	85.7
FY27	75.2	97.7	86.5	71.6	104.9	88.2
FY28	77.5	100.7	89.1	73.7	108.0	90.9
FY29	79.8	103.7	91.8	76.0	111.3	93.6
FY30	82.2	106.8	94.5	78.2	114.6	96.4
FY31	84.7	110.0	97.3	80.6	118.1	99.3
FY32	87.2	113.3	100.3	83.0	121.6	102.3
FY33	89.8	116.7	103.3	85.5	125.3	105.4
FY34	92.5	120.2	106.4	88.1	129.0	108.5
FY35	95.3	123.8	109.6	90.7	132.9	111.8
FY36	98.2	127.5	112.9	93.4	136.9	115.1
FY37	101.1	131.4	116.2	96.2	141.0	118.6
FY38	104.2	135.3	119.7	99.1	145.2	122.2
FY39	107.3	139.4	123.3	102.1	149.6	125.8
FY40	110.5	143.5	127.0	105.1	154.0	129.6
FY41	113.8	147.8	130.8	108.3	158.7	133.5
FY42	117.2	152.3	134.8	111.5	163.4	137.5
FY43	120.7	156.8	138.8	114.9	168.3	141.6
FY44	124.4	161.5	143.0	118.3	173.4	145.9

Mid C Power Forecast
Average Annual $/MWH
Provided by BPA - January 9, 2007

	Outage Impact Price - March - April			Summer Derate Price - August			Average Annual Price		
	Alt 1	Alt 2	Ave Al t1 &2	Alt 1	Alt 2	Ave Al t1 &2	Alt 1	Alt 2	Ave Al t1 &2
FY07	38.01	36.97	37.5				42.6	41.8	42.2
FY08	37.84	45.02	41.4	48.47	63.74	56.11	46.8	55.8	51.3
FY09	36.32	47.65	42.0	47.36	70.47	58.91	45.8	60.3	53.1
FY10	34.76	46.31	40.5	46.54	67.98	57.26	44.4	58.5	51.4
FY11	33.67	44.24	39.0	44.92	65.97	55.45	42.7	56.3	49.5
FY12	35.46	42.00	38.7	42.97	60.14	51.55	42.5	53.7	48.1
FY13	37.19	43.98	40.6	44.00	59.88	51.94	44.2	53.2	48.7
FY14	39.84	49.24	44.5	47.01	67.04	57.02	46.7	56.9	51.8
FY15	42.05	54.03	48.0	50.22	73.57	61.89	49.0	63.1	56.0
FY16	54.36	70.61	62.5	51.7	75.8	63.8	51.8	64.9	58.3
FY17	55.99	72.73	64.4	53.3	78.1	65.7	53.4	66.8	60.1
FY18	57.67	74.91	66.3	54.9	80.4	67.6	55.0	68.8	61.9
FY19	59.40	77.16	68.3	56.5	82.8	69.7	56.6	70.9	63.7
FY20	61.18	79.47	70.3	58.2	85.3	71.8	58.3	73.0	65.7
FY21	63.02	81.86	72.4	60.0	87.8	73.9	60.1	75.2	67.6
FY22	64.91	84.31	74.6	61.8	90.5	76.1	61.9	77.4	69.7
FY23	66.85	86.84	76.8	63.6	93.2	78.4	63.7	79.8	71.7
FY24	68.86	89.45	79.2	65.5	96.0	80.8	65.6	82.2	73.9
FY25	70.9	92.1	81.5	67.5	98.9	83.2	67.6	84.6	76.1
FY26	73.1	94.9	84.0	69.5	101.8	85.7	69.6	87.2	78.4
FY27	75.2	97.7	86.5	71.6	104.9	88.2	71.7	89.8	80.7
FY28	77.5	100.7	89.1	73.7	108.0	90.9	73.9	92.5	83.2
FY29	79.8	103.7	91.8	76.0	111.3	93.6	76.1	95.2	85.7
FY30	82.2	106.8	94.5	78.2	114.6	96.4	78.4	98.1	88.2
FY31	84.7	110.0	97.3	80.6	118.1	99.3	80.7	101.0	90.9
FY32	87.2	113.3	100.3	83.0	121.6	102.3	83.1	104.1	93.6
FY33	89.8	116.7	103.3	85.5	125.3	105.4	85.6	107.2	96.4
FY34	92.5	120.2	106.4	88.1	129.0	108.5	88.2	110.4	99.3
FY35	95.3	123.8	109.6	90.7	132.9	111.8	90.9	113.7	102.3
FY36	98.2	127.5	112.9	93.4	136.9	115.1	93.6	117.1	105.4
FY37	101.1	131.4	116.2	96.2	141.0	118.6	96.4	120.6	108.5
FY38	104.2	135.3	119.7	99.1	145.2	122.2	99.3	124.3	111.8
FY39	107.3	139.4	123.3	102.1	149.6	125.8	102.3	128.0	115.1
FY40	110.5	143.5	127.0	105.1	154.0	129.6	105.3	131.8	118.6
FY41	113.8	147.8	130.8	108.3	158.7	133.5	108.5	135.8	122.1
FY42	117.2	152.3	134.8	111.5	163.4	137.5	111.7	139.9	125.8
FY43	120.7	156.8	138.8	114.9	168.3	141.6	115.1	144.1	129.6
FY44	124.4	161.5	143.0	118.3	173.4	145.9	118.5	148.4	133.5

Escalated at 3% Compounded to show end of plant extended life

ENERGY NORTHWEST

Condenser Replacement Project Update & Chronology

Project No. 00608601

September 30, 2008

Brian Berglin

Modifications To Plant

Primary purpose for relocation of equipment:

- Items are in the installation and removal path of personnel and equipment entering and leaving the condenser
- Equipment relocated during R19 will decrease the impact on R20 outage duration
- The work in plant will be completed over 5 Phases starting with cycle 19 and ending in Cycle 21

How Solutions to Relocation of Equipment & Components were Achieved?

- Seven studies were performed
- Meetings were held with station stakeholders
- Design engineering contractor (Sargent and Lundy) and installation augmented staff confirmed feasibility

Study Evaluations

Studies obtained conclusions using the following criteria:

- Safety impact
- Cost impact
- Schedule impact
- Value Analysis methodology
- Meetings were held with station stakeholders to evaluate other impacts and obtain consensus

Studies Performed

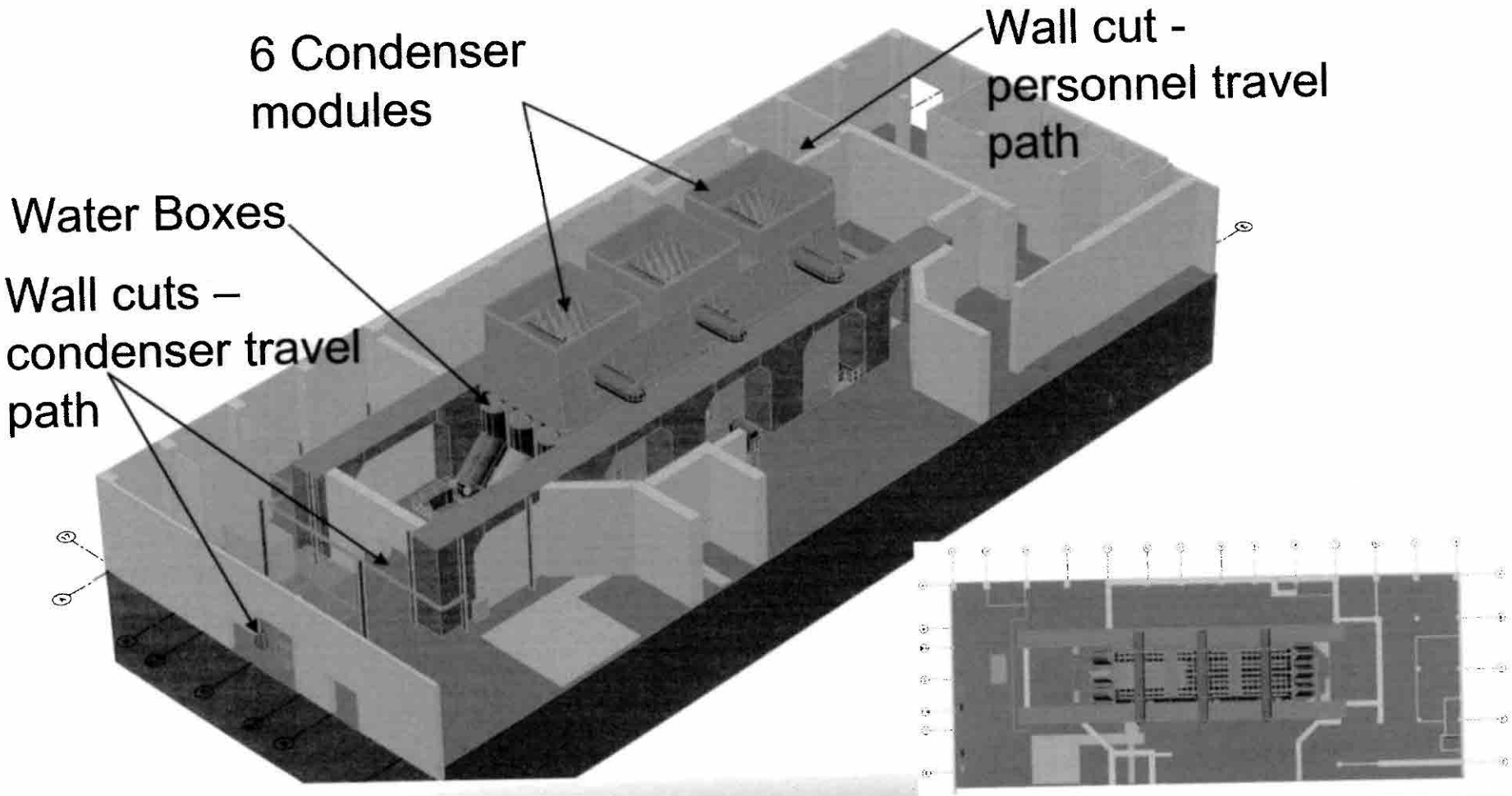
- Conceptual study – baseline (by Westinghouse)
- Breakout studies include:
  1. Enlarge proposed opening on walls 15 and 17
  2. Stator Cooling Water Skid Relocation
  3. H2 and Air Injection Panel Relocation
  4. Temporary Shielding vs Block wall for wall 15
  5. Temporary Shielding vs Block wall for wall 7
  6. Fire Protection Line relocation options
  7. Extension of RCA at west side of Turbine Building

Chronology of Work

The following slides depict the work to be performed in the following phases

- Cycle 19 - On line
- R-19 - 34 Day Planned Outage
- Cycle 20 - On line
- R-20 - 75 Day Outage (lower in prog)
- Cycle 21 - On line

Overall View of Condenser Project

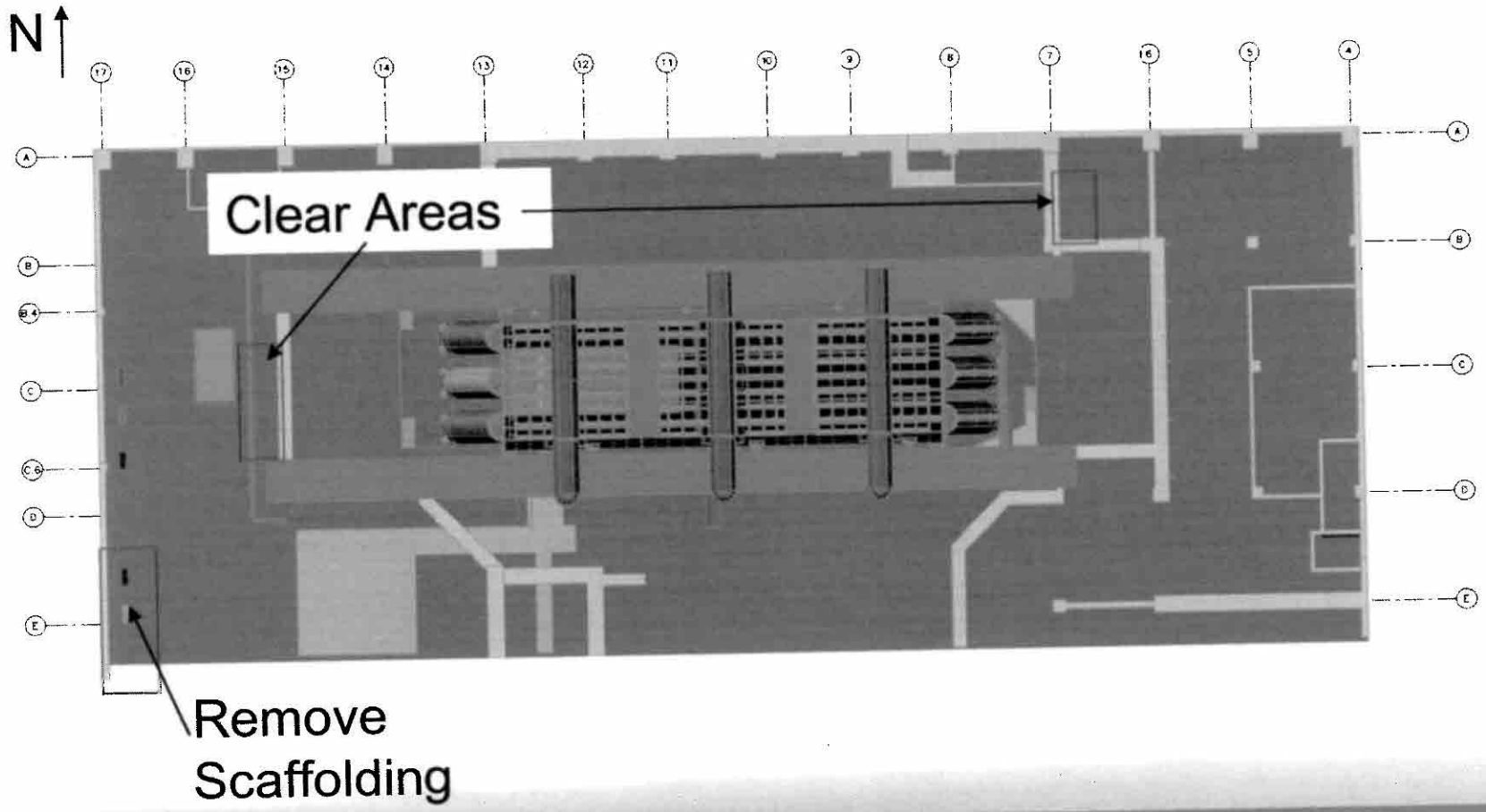


ENERGY NORTHWEST

Work Performed Cycle R-19

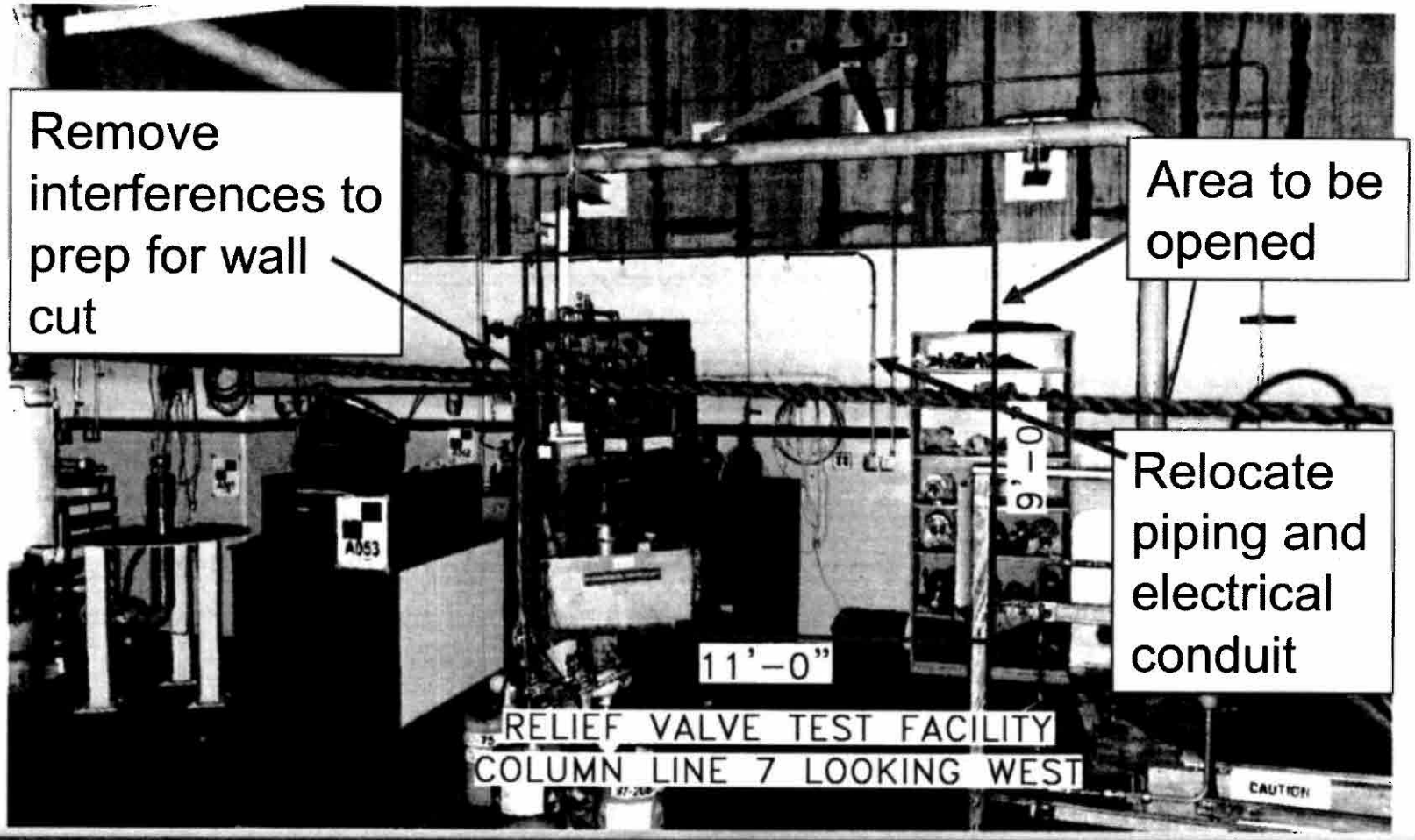
- Remove carts, scaffolding and other equipment located where cuts are to be made and in Condenser walls
- Remove scaffolding retainer racks where H2 and Air Injection panels are to be relocated

Affected Areas of Plant for Cycle 19



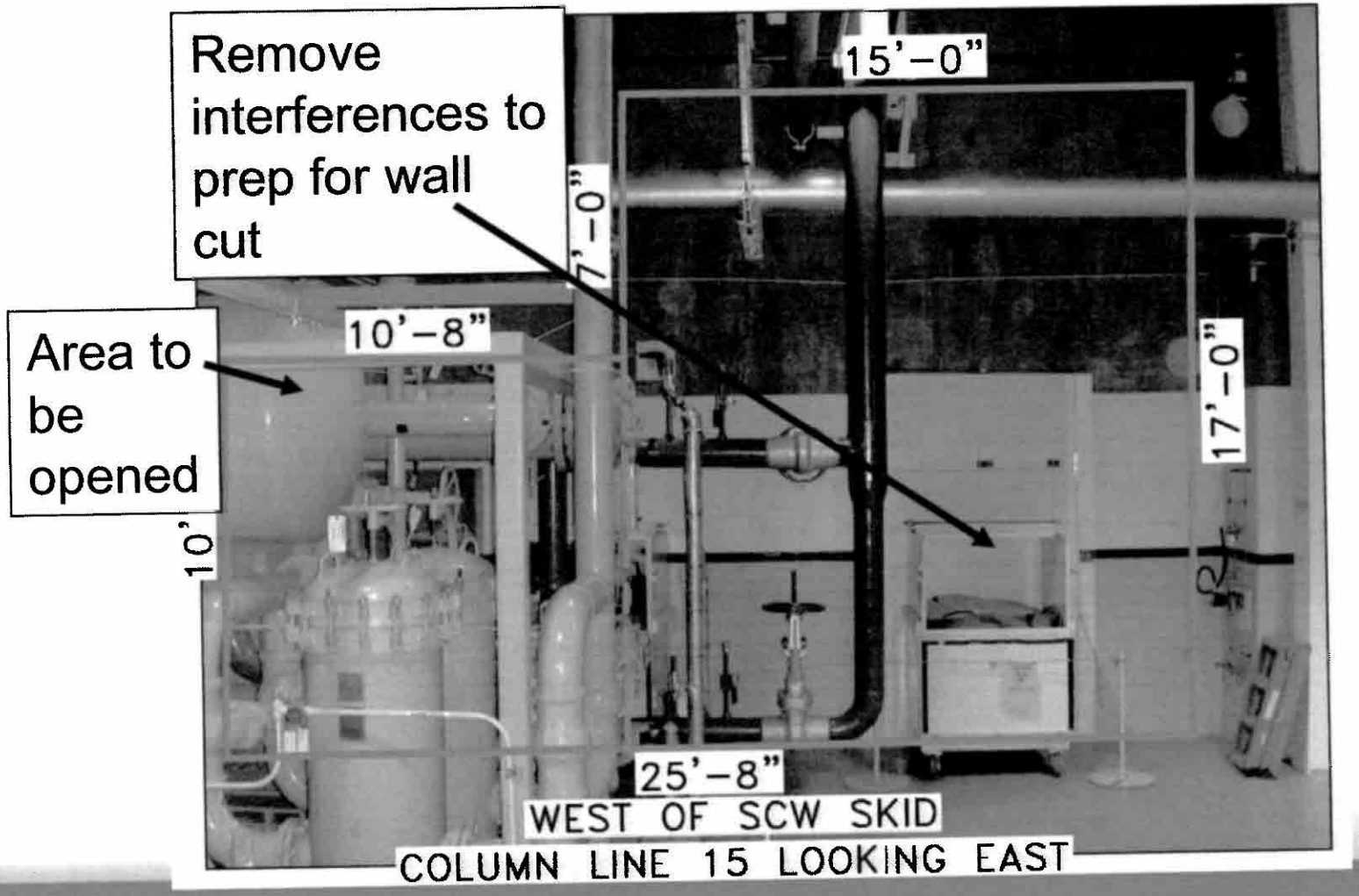
ENERGY NORTHWEST

Cycle 19 Work – Column Line 7



ENERGY NORTHWEST

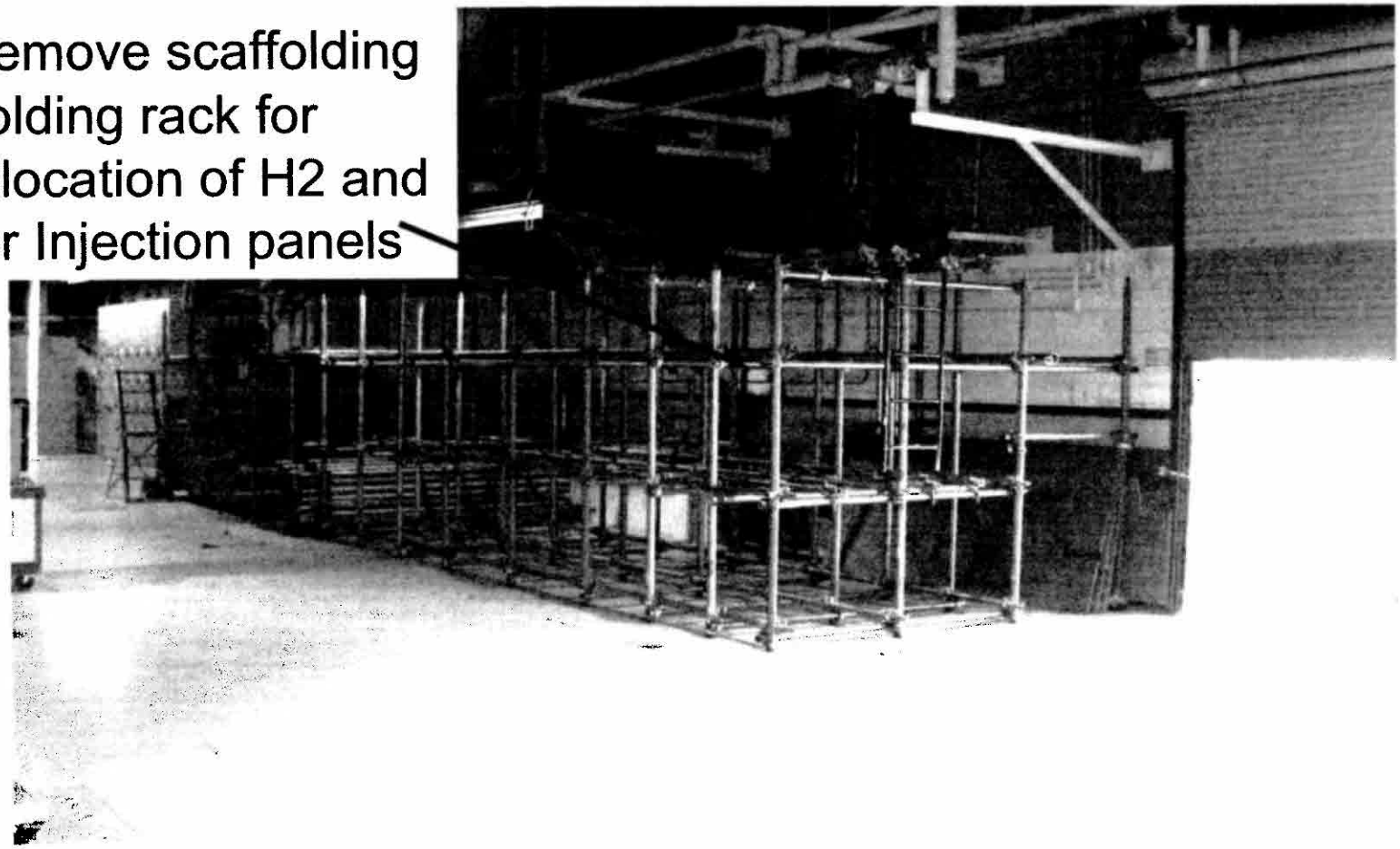
Cycle 19 Work – Column Line 15



ENERGY NORTHWEST

Cycle 19 Work – TGB West Wall

Remove scaffolding holding rack for relocation of H2 and Air Injection panels

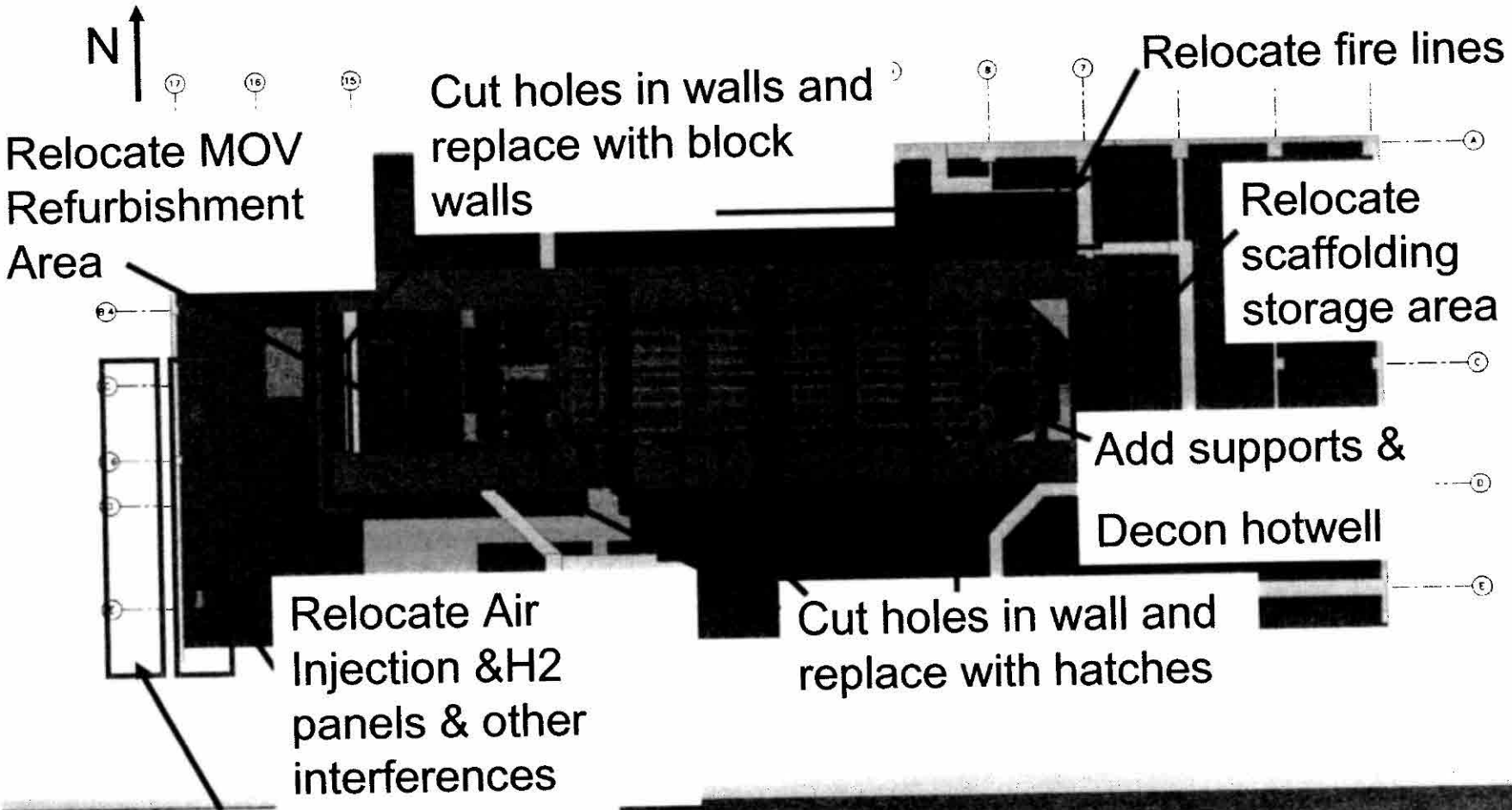


ENERGY NORTHWEST

Work Performed in R-19

- Cut openings in Condenser walls at column line 7 and 15
- Replace cut Condenser walls with block walls
- Relocate H2 and Air Injection panels
- Relocate u/g H2 and spare O2 feed lines west of TGB
- Relocate the fire lines at column line 7 on 441' level
- Cut and install hatches on Condenser shell
- Install performance monitoring instrumentation
- West side Travel Path Interference removal (cond pipe)
- Relocate MOV refurbish area
- Install hotwell supports
- Decon hotwell

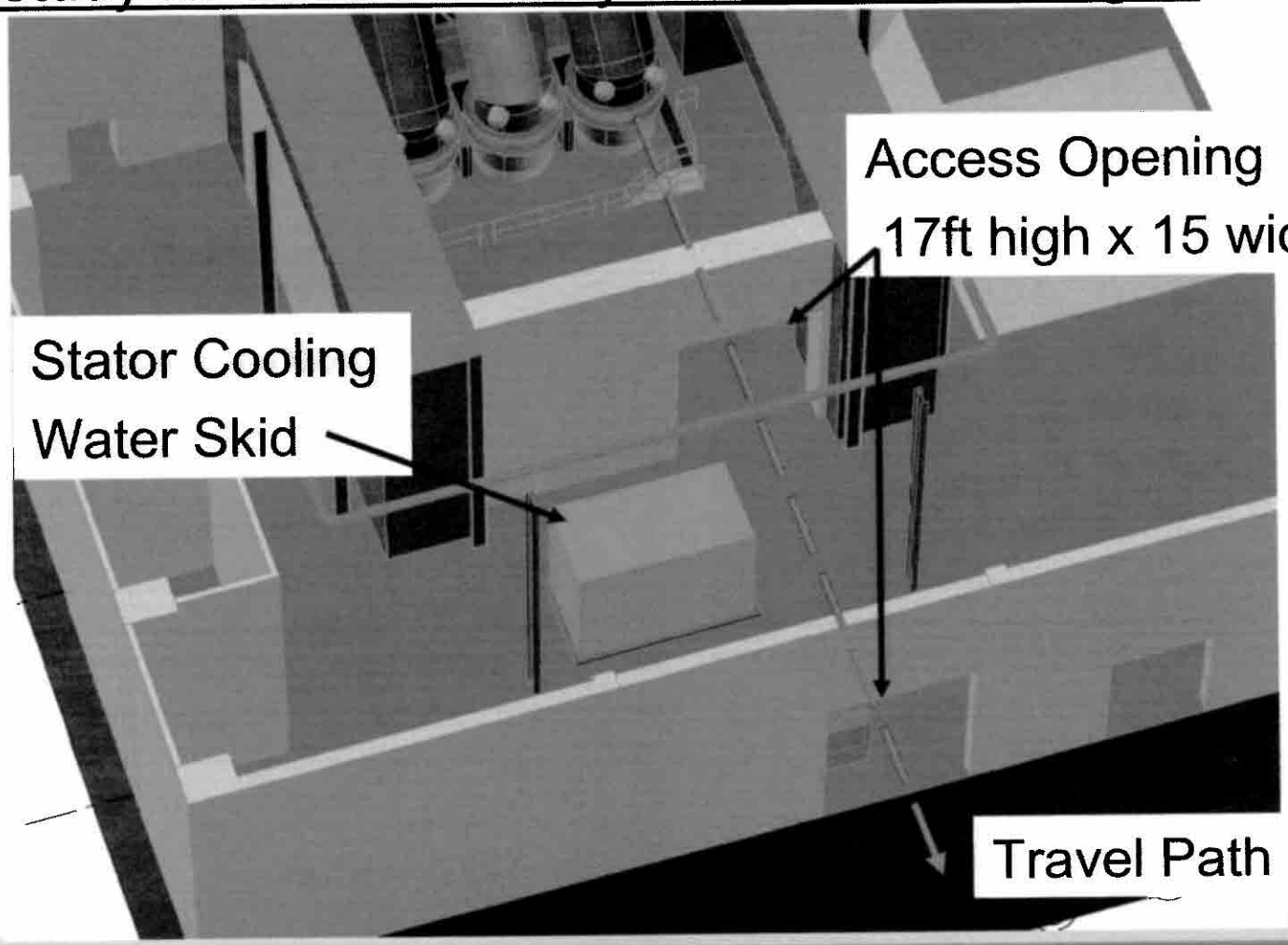
Affected Areas of Plant for R-19



ENERGY NORTHWEST

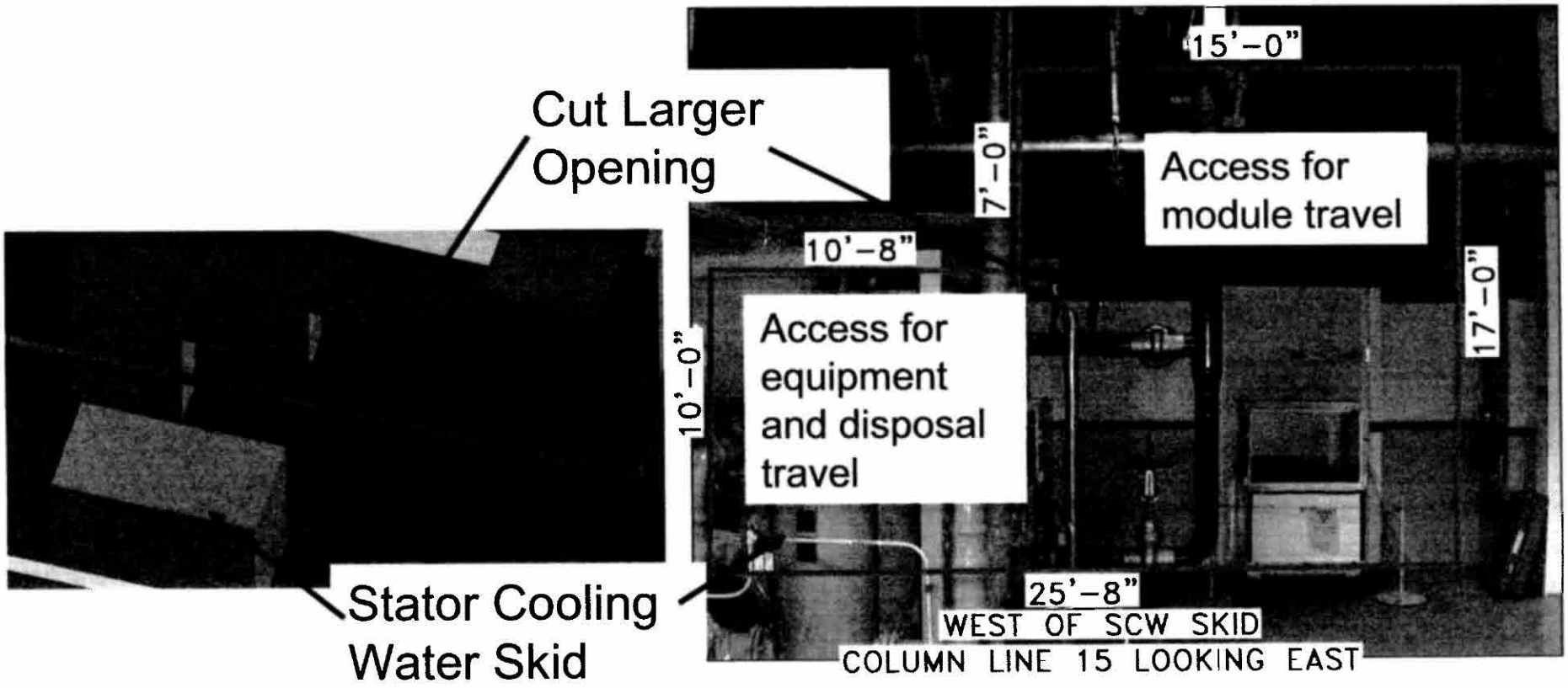
Baseline Configuration had smaller opening.

<u>See study for details on why access was enlarged</u>



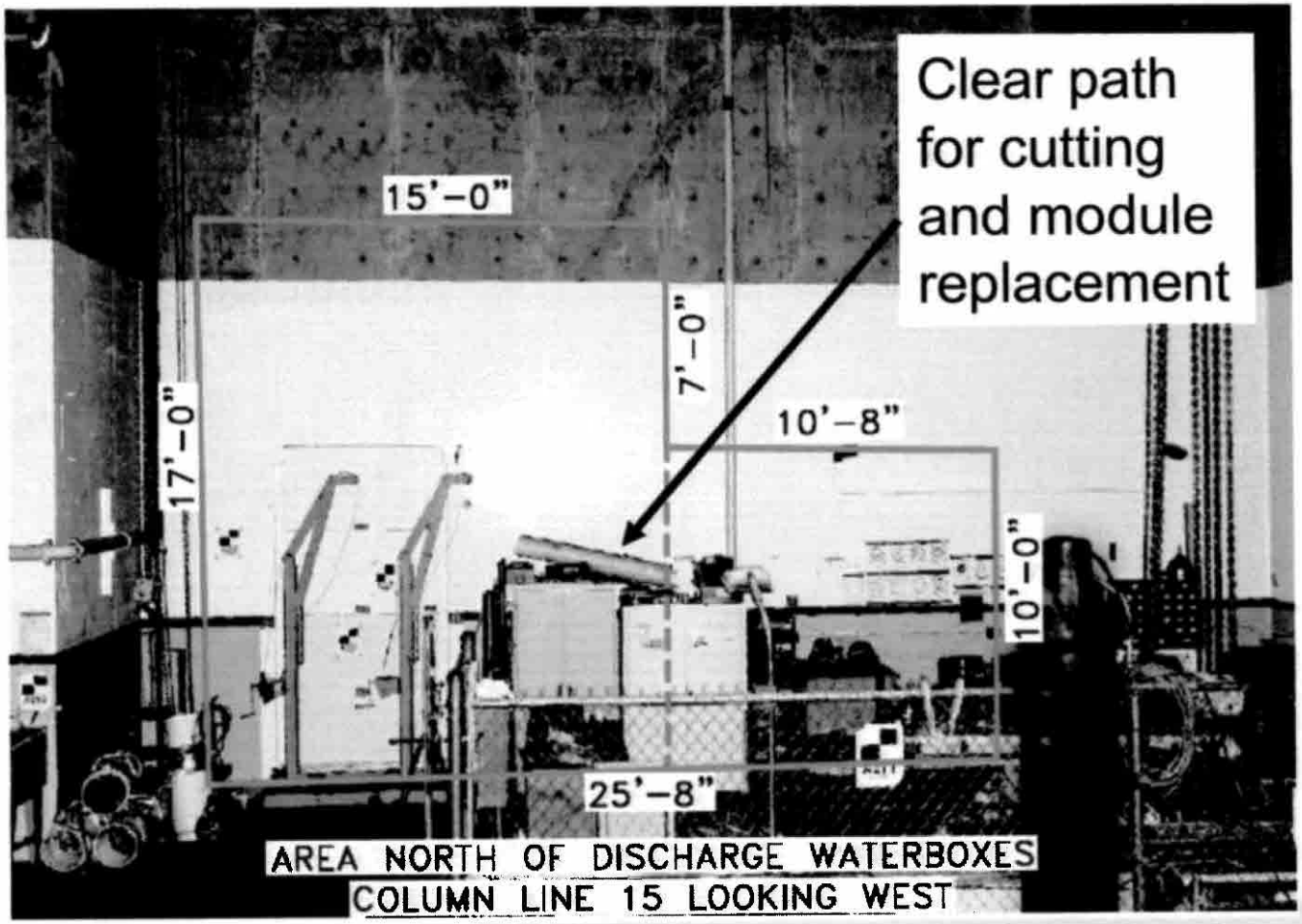
ENERGY NORTHWEST

R-19 Work - Cut Openings in Condenser Walls at Column Line 15



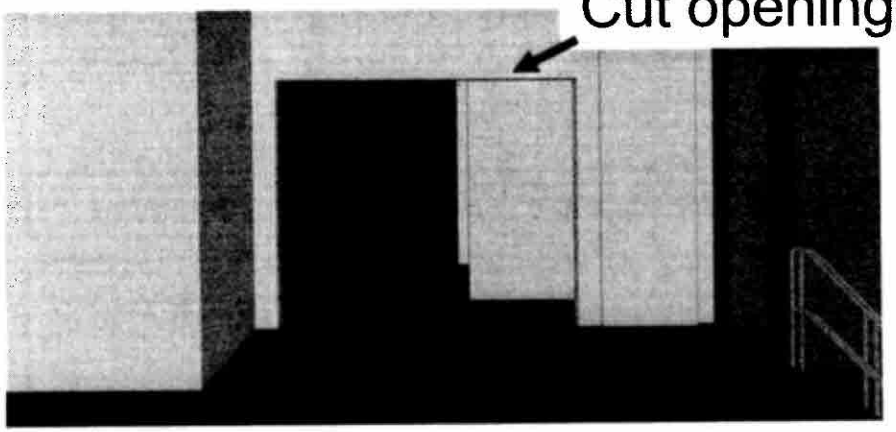
ENERGY NORTHWEST

R-19 Work – Opening continued



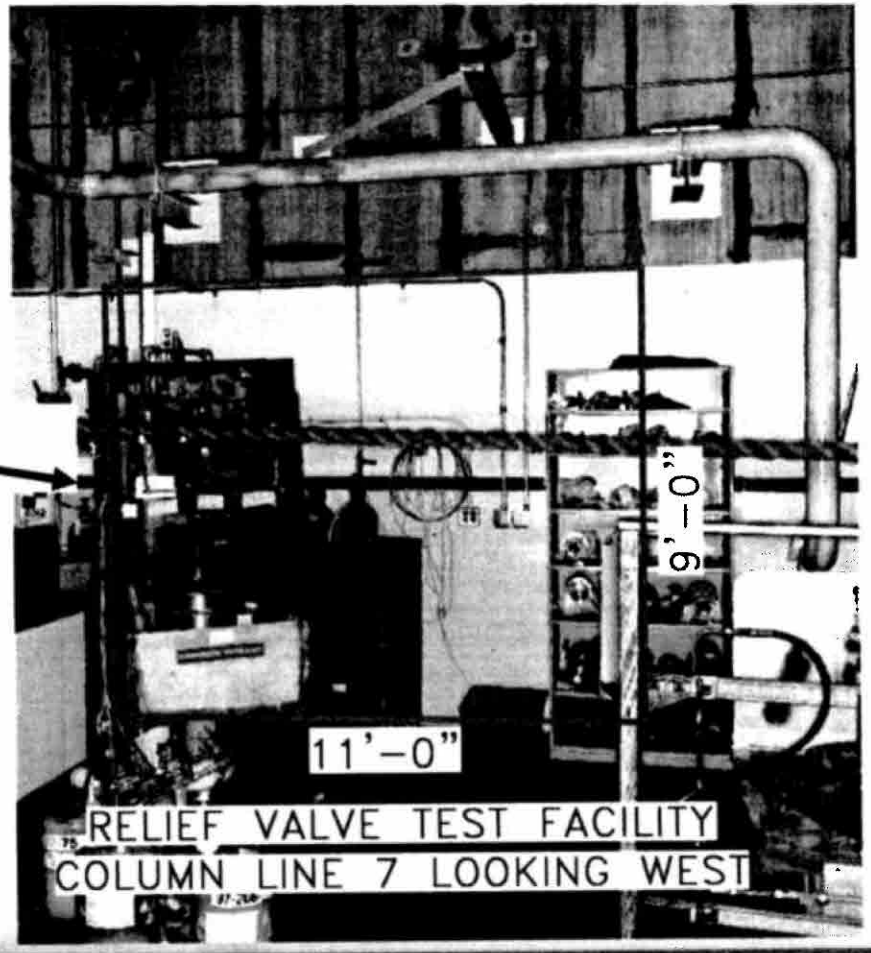
ENERGY NORTHWEST

R-19 Work - Cut Openings in Condenser Walls at Column Line 7



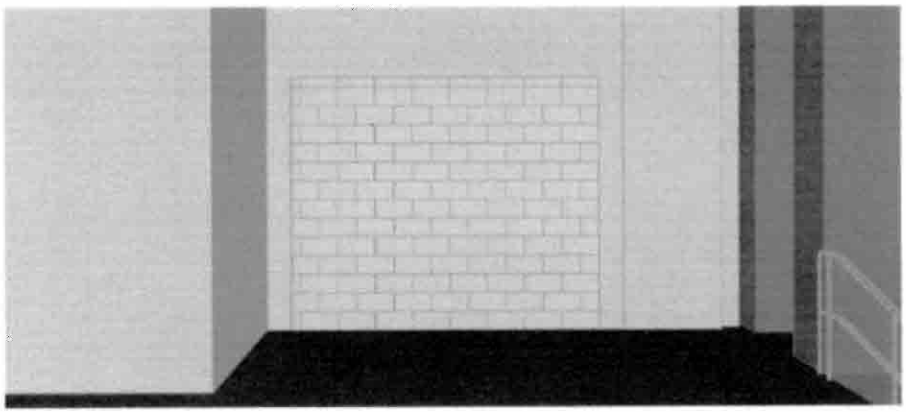
Cut opening

Looking East – other side of cut

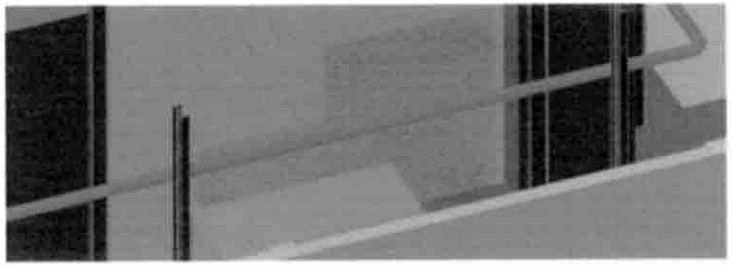


ENERGY NORTHWEST

R-19 Work - Replace Cut Condenser Walls with Block Walls

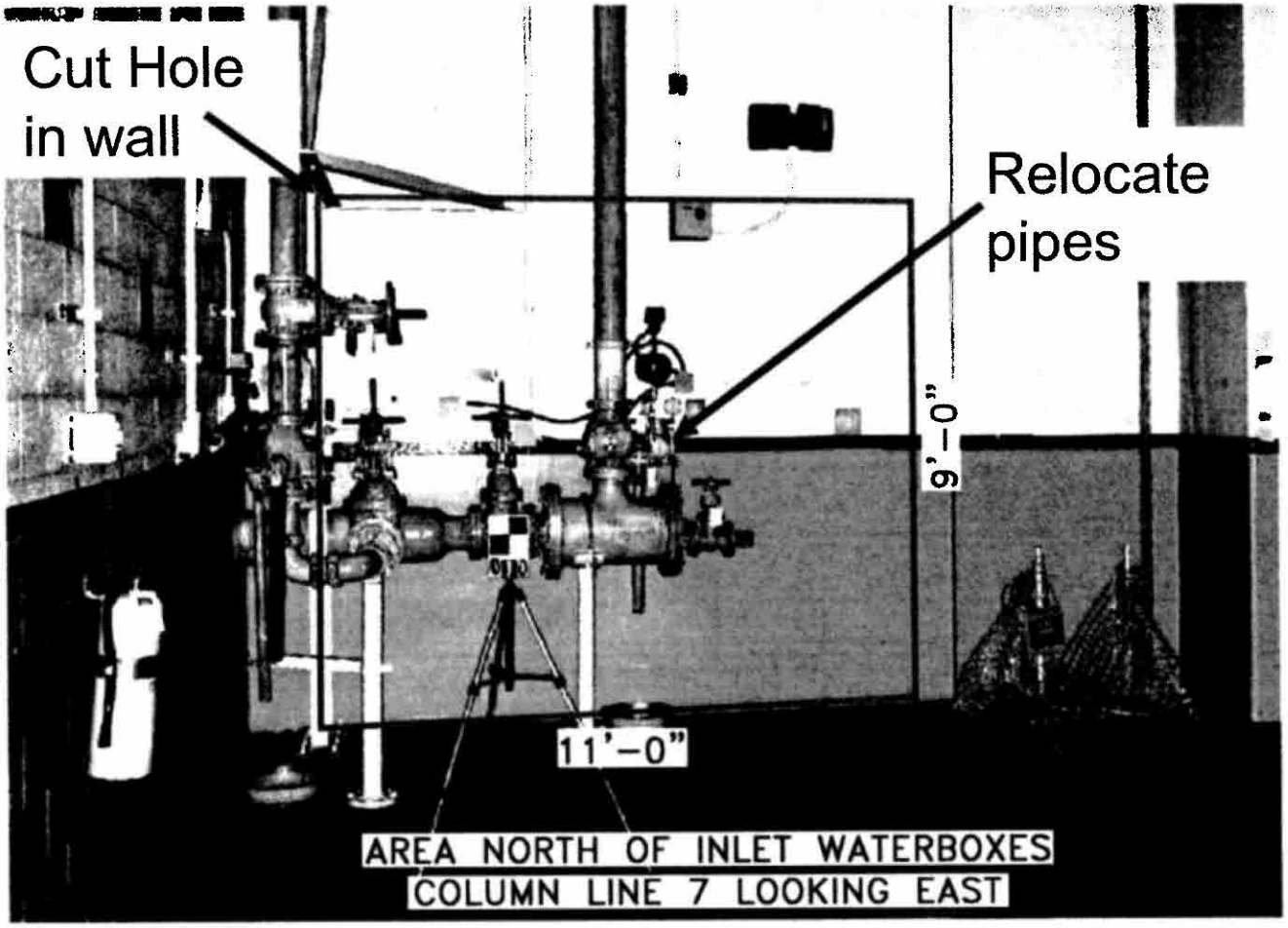


Column line 7 Looking East



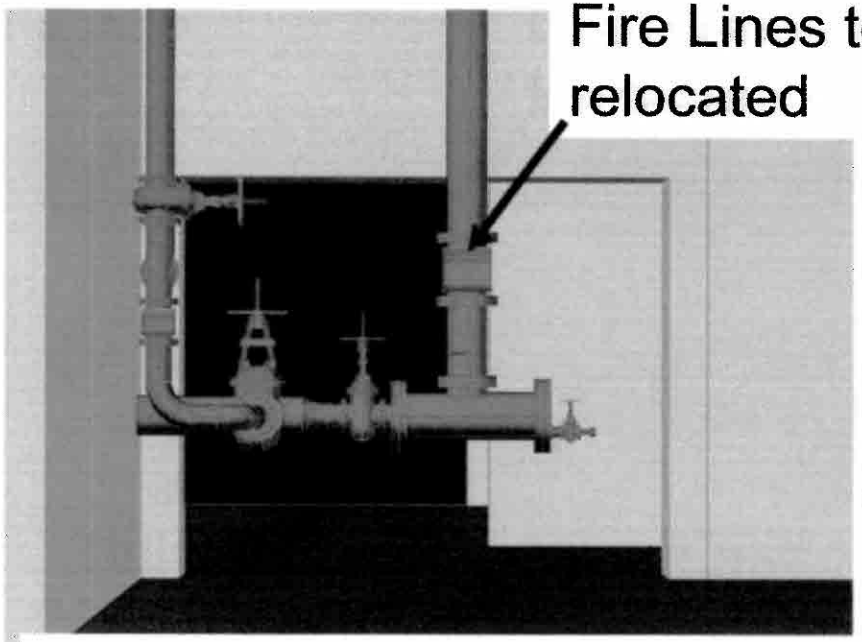
Column line 15 Looking East

R-19 Work – Relocate Fire Lines

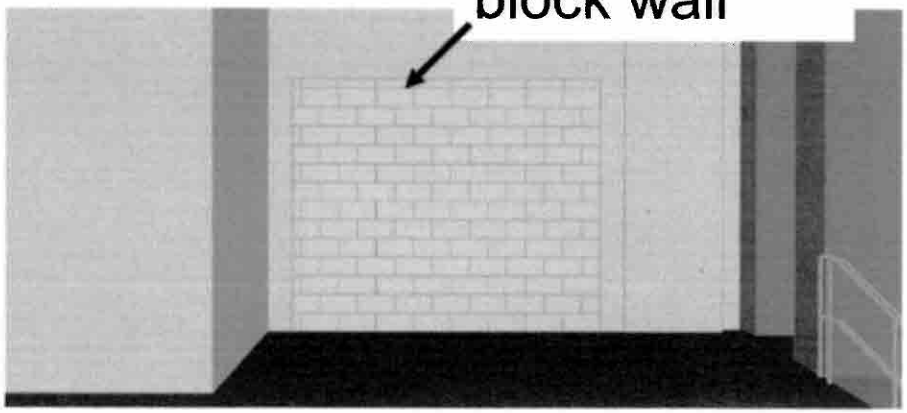


ENERGY NORTHWEST

R-19 Work - Relocate Fire Lines Continued



- Column line 7 Looking East

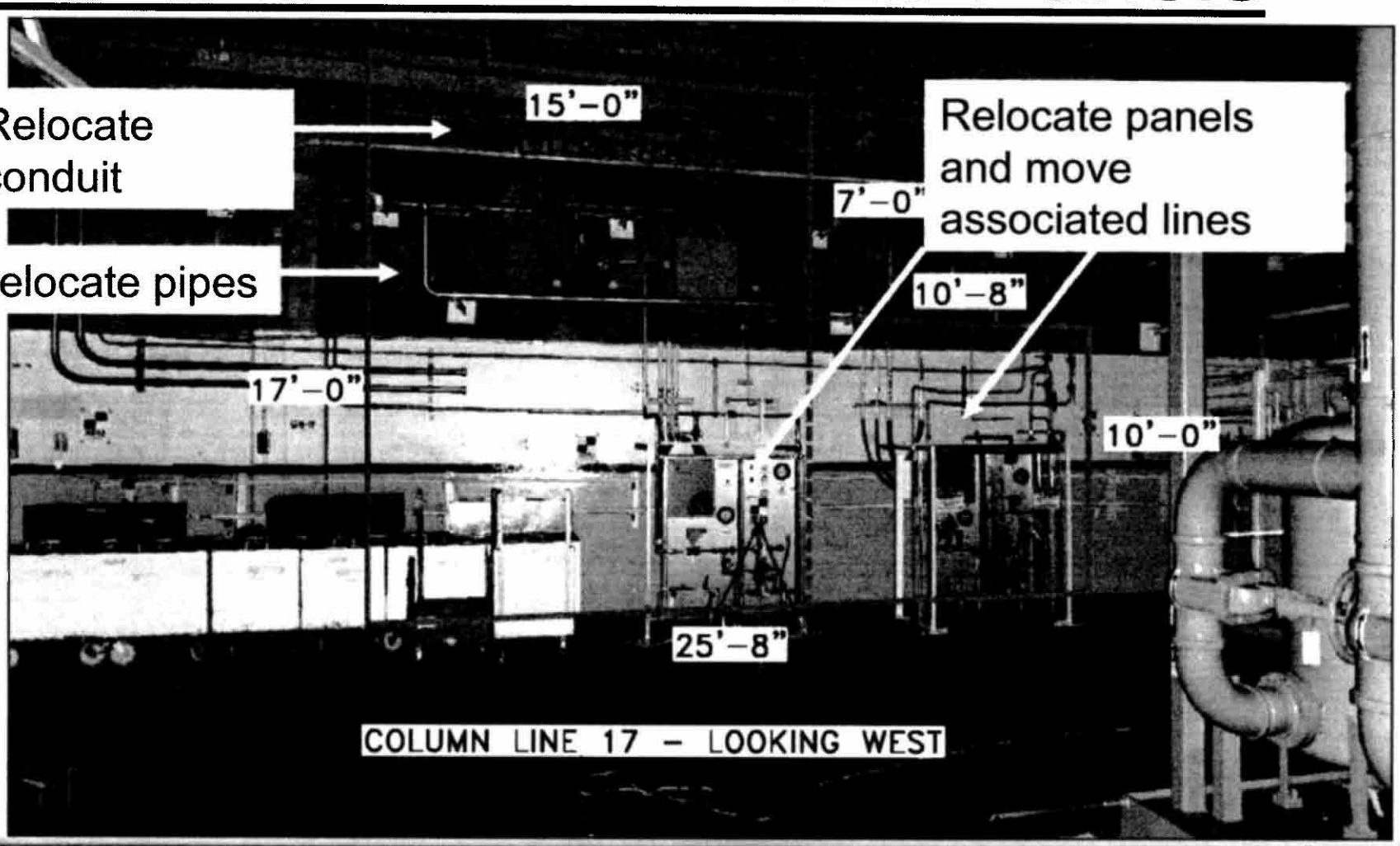


Column line 7 Looking East

Final configuration shown

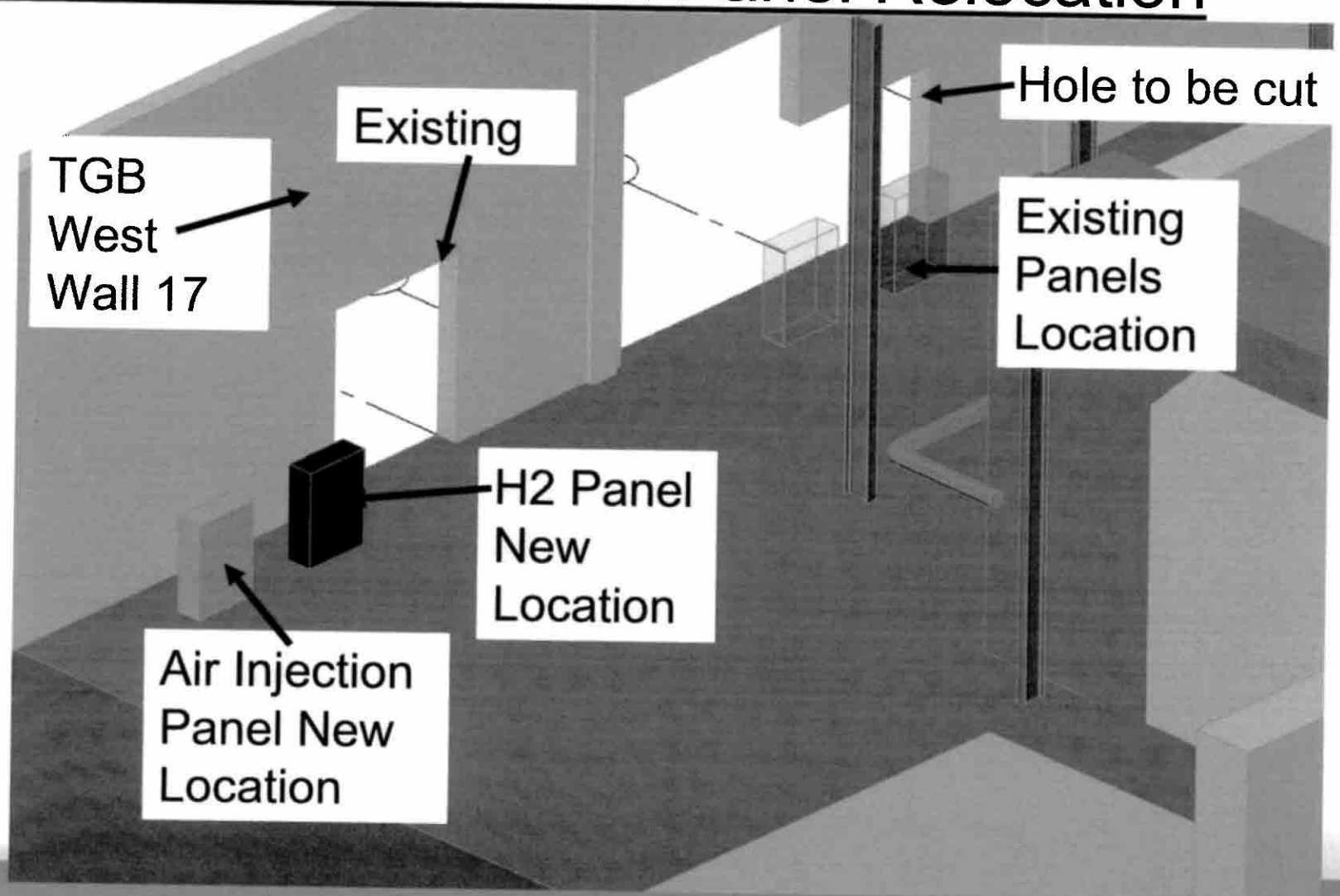
ENERGY NORTHWEST

R-19 Work – Relocate Panels



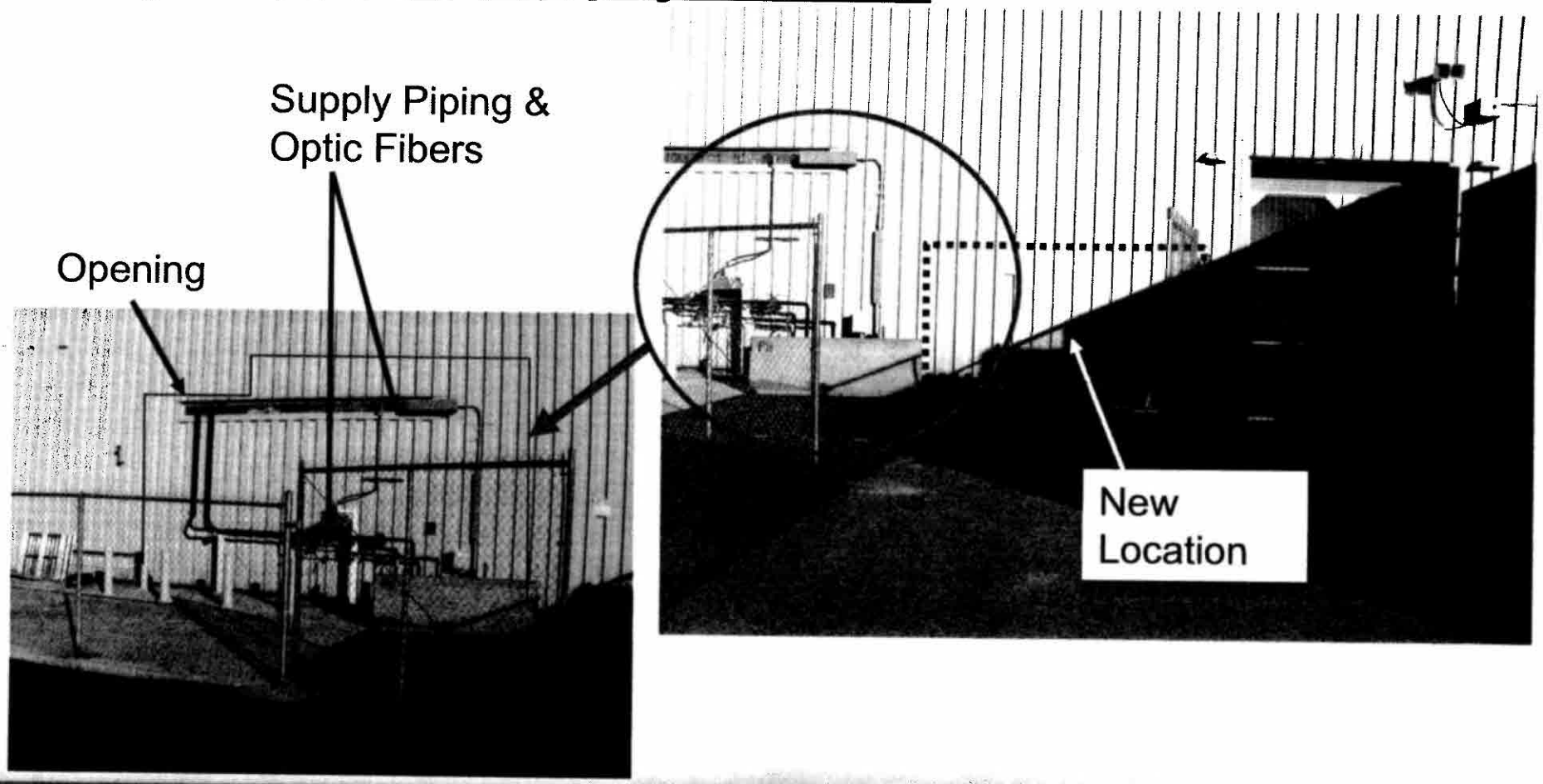
ENERGY NORTHWEST

R-19 Work - H2 & 02 Panel Relocation



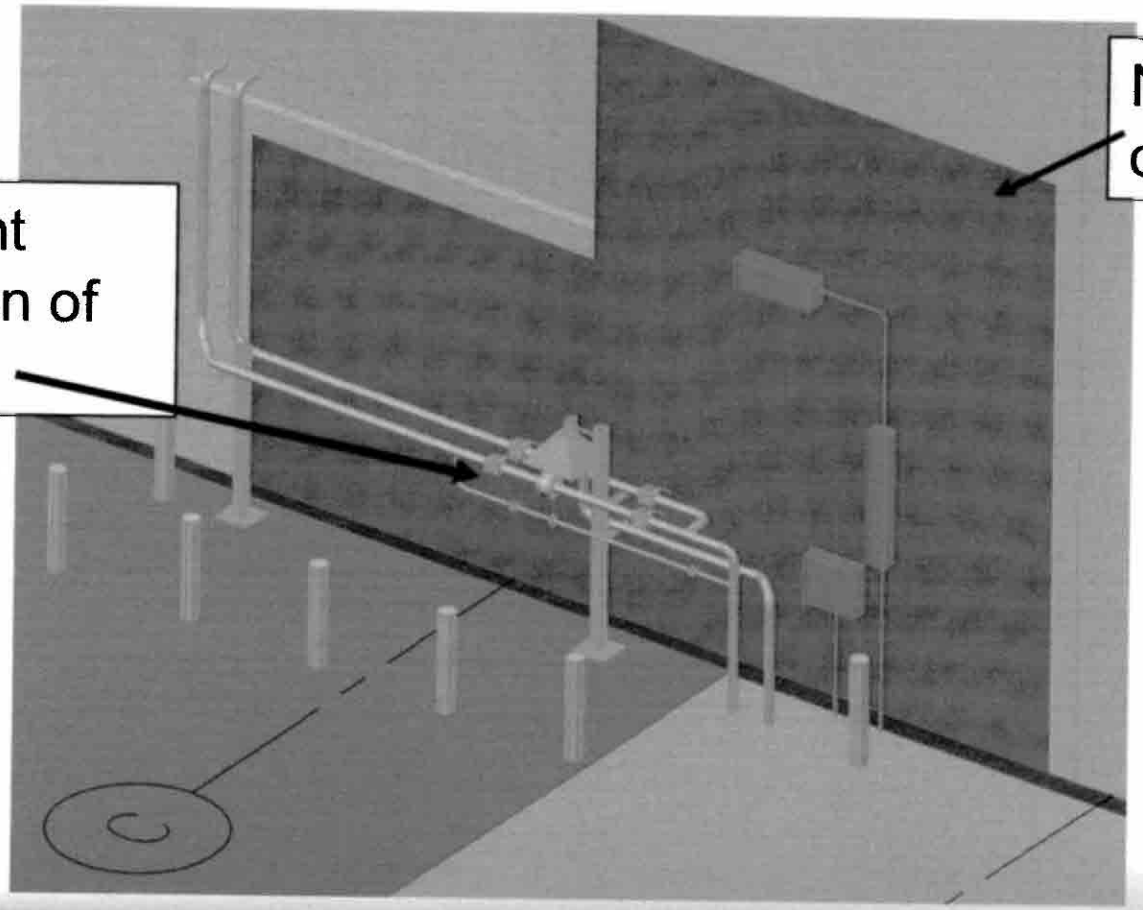
ENERGY NORTHWEST

R-19 Work- Relocate H2 & Air Injection Supply Lines



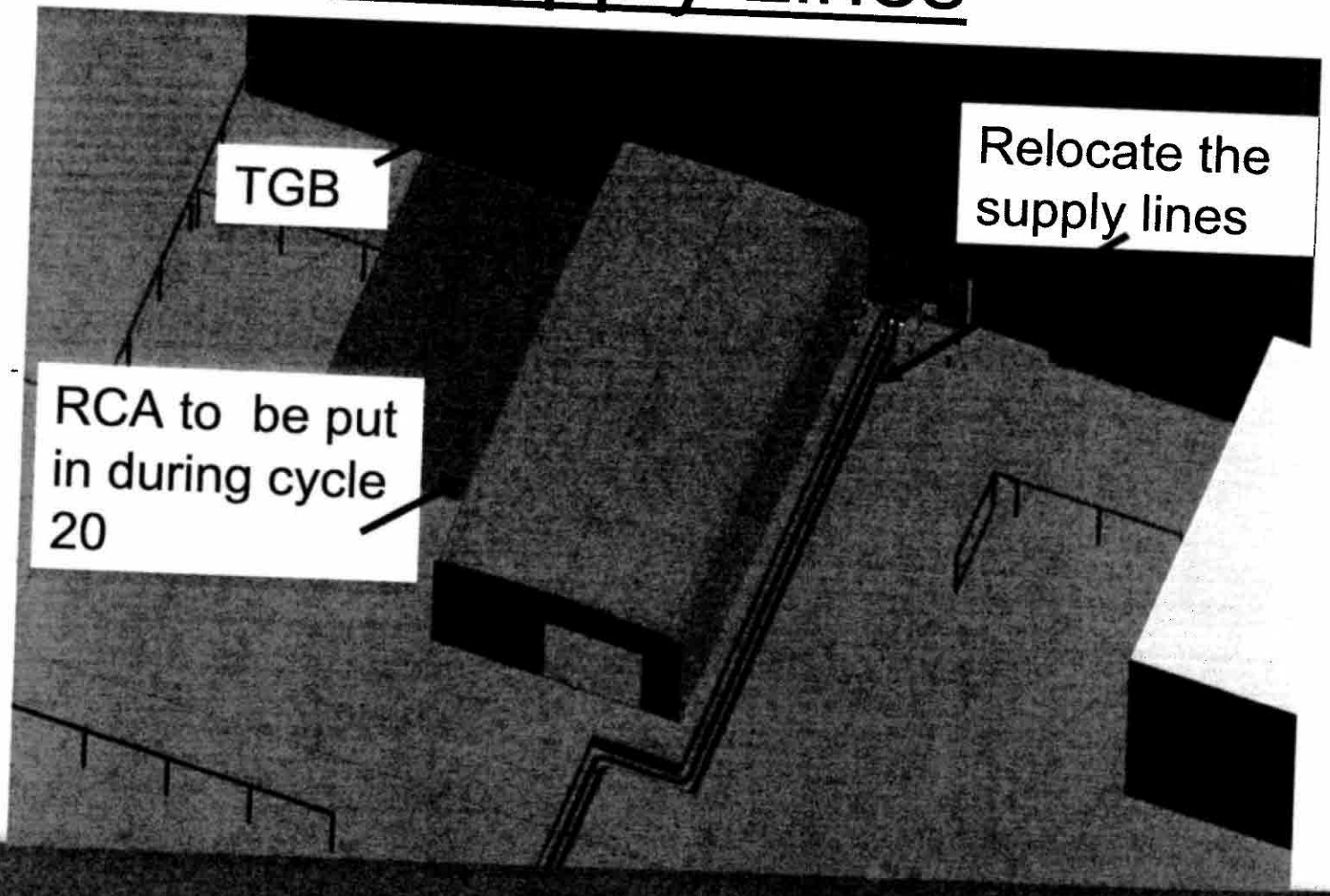
ENERGY NORTHWEST

R-19 Work- Relocate H2 & Air Injection Supply Lines



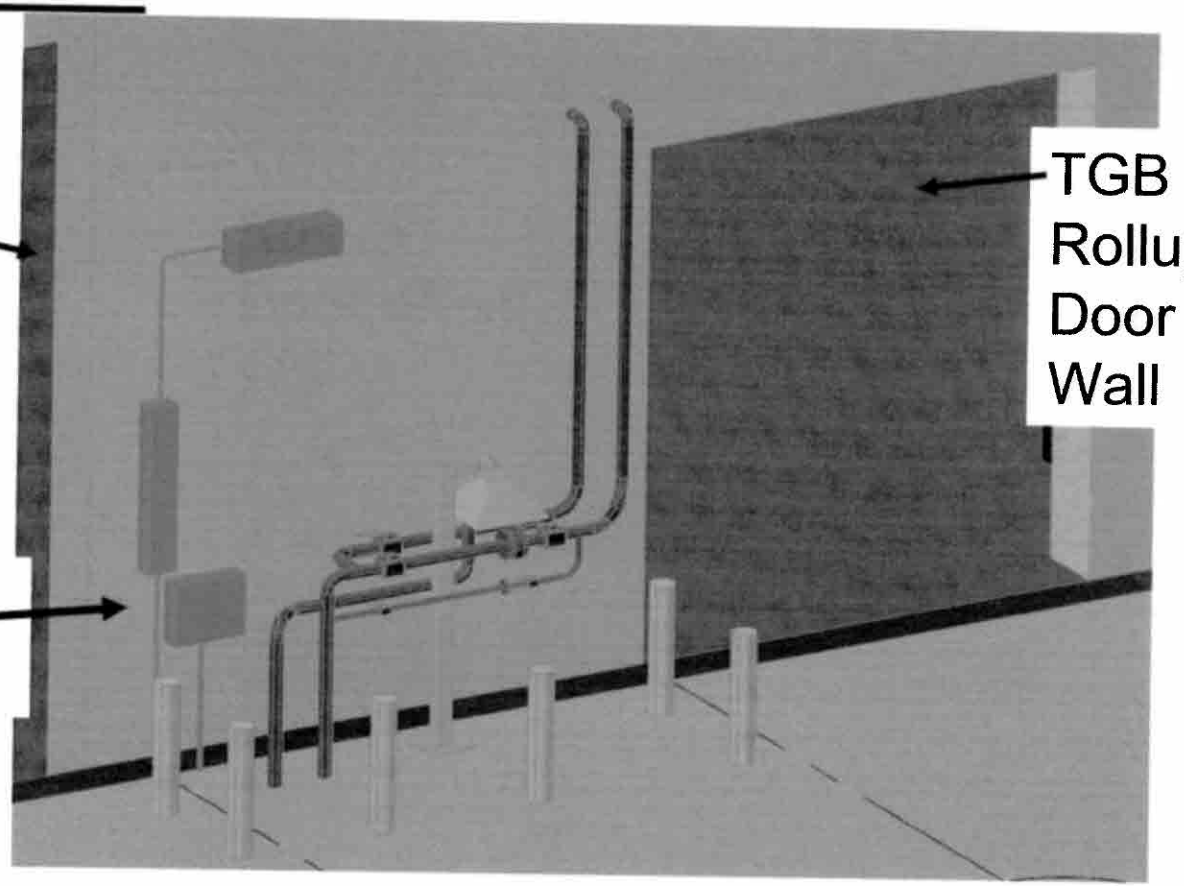
ENERGY NORTHWEST

R-19 Work- Relocate H2 & Air Injection Supply Lines



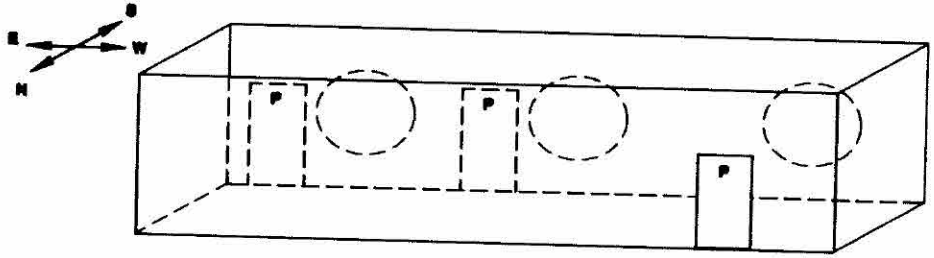
ENERGY NORTHWEST

R-19 Work- Relocate H2 & Air Injection Supply Lines



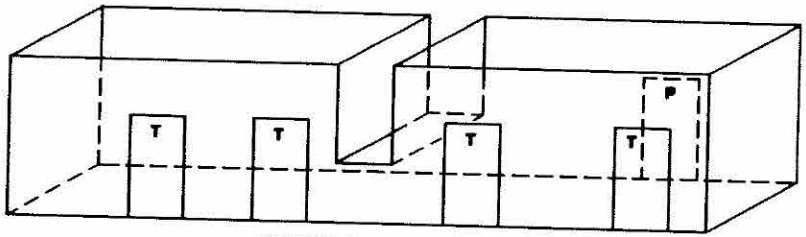
ENERGY NORTHWEST

R-19 Work – Installation of Hatches



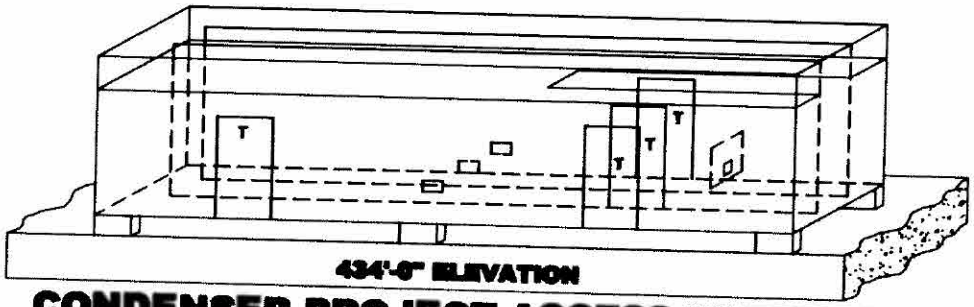
471'-6" ELEVATION

(3) PERMANENT. REPLACES (1) EXISTING 20"Ø HATCH. BETTER FOR PERSONNEL, MATERIAL, EQUIPMENT & SAFETY FOR ALL FUTURE OUTAGES. INSTALLED DURING R-19



441'-6" ELEVATION

(1) PERMANENT ON SOUTHWEST SIDE. ALLOWS ACCESS/SAFETY BECAUSE OF OPENING IN MIDDLE OF FALSE FLOOR. INSTALLED DURING R-19. (4) TEMPORARY HATCHES FOR R-20 ACCESS INSTALLED DURING R-20.



434'-6" ELEVATION

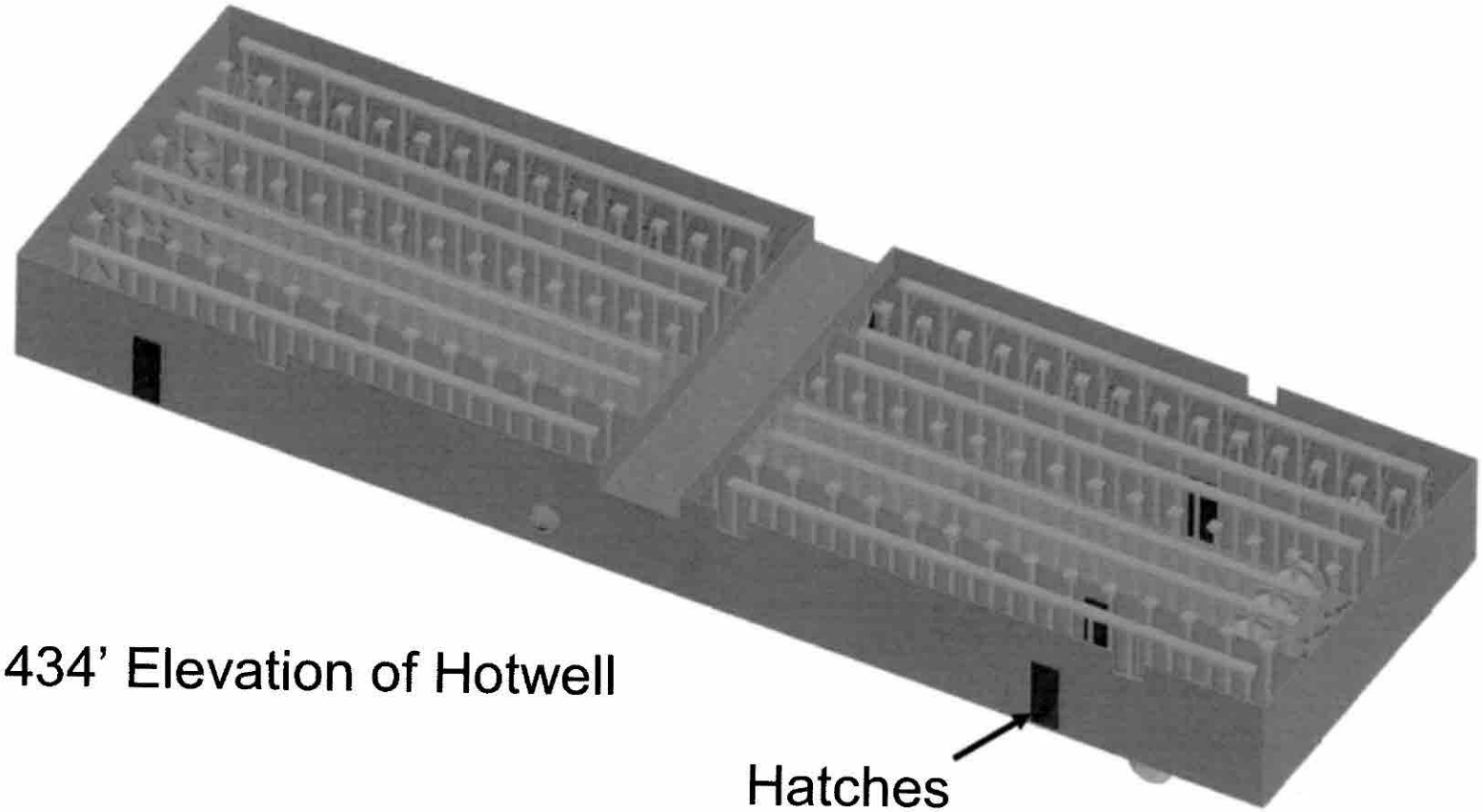
(2) EXTERIOR AND (2) INTERIOR FOR ACCESS/SAFETY AND MOBILITY. INSTALLED DURING R-19 AND REUSED DURING R-20. HVAC PENETRATIONS CUT DURING R-19

CONDENSER PROJECT ACCESS HATCHES

(4) PERMANENT (6) TEMPORARY (EXTERIOR) (2) TEMPORARY (INTERIOR)

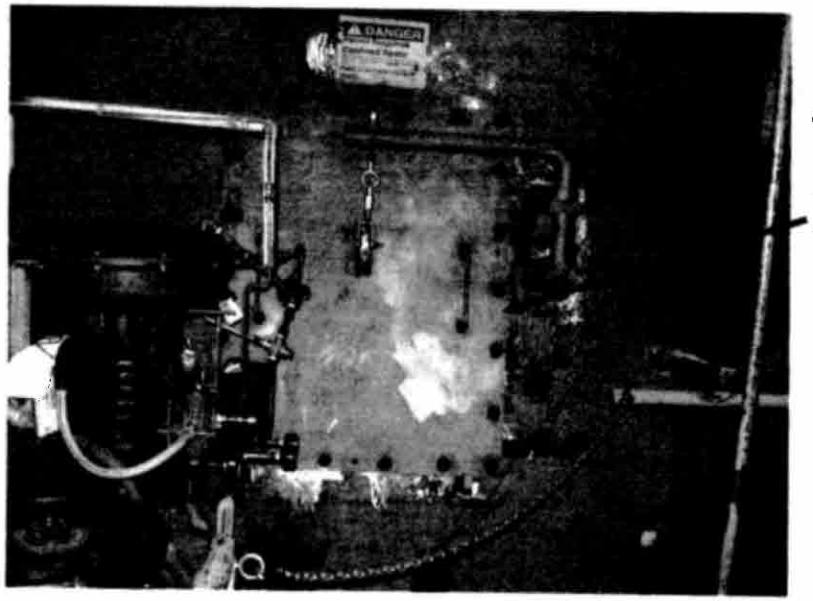
ENERGY NORTHWEST

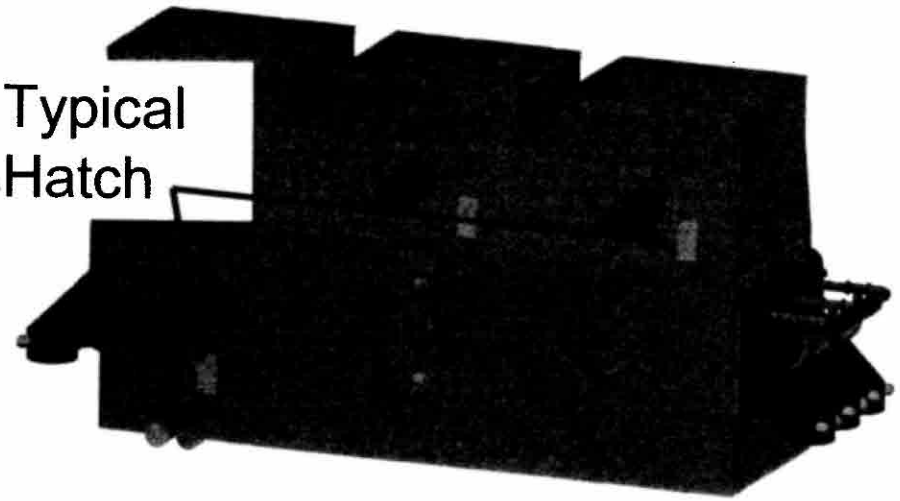
R-19 Work – Installation of Hatches



ENERGY NORTHWEST

R-19 Work – Installation of Hatches





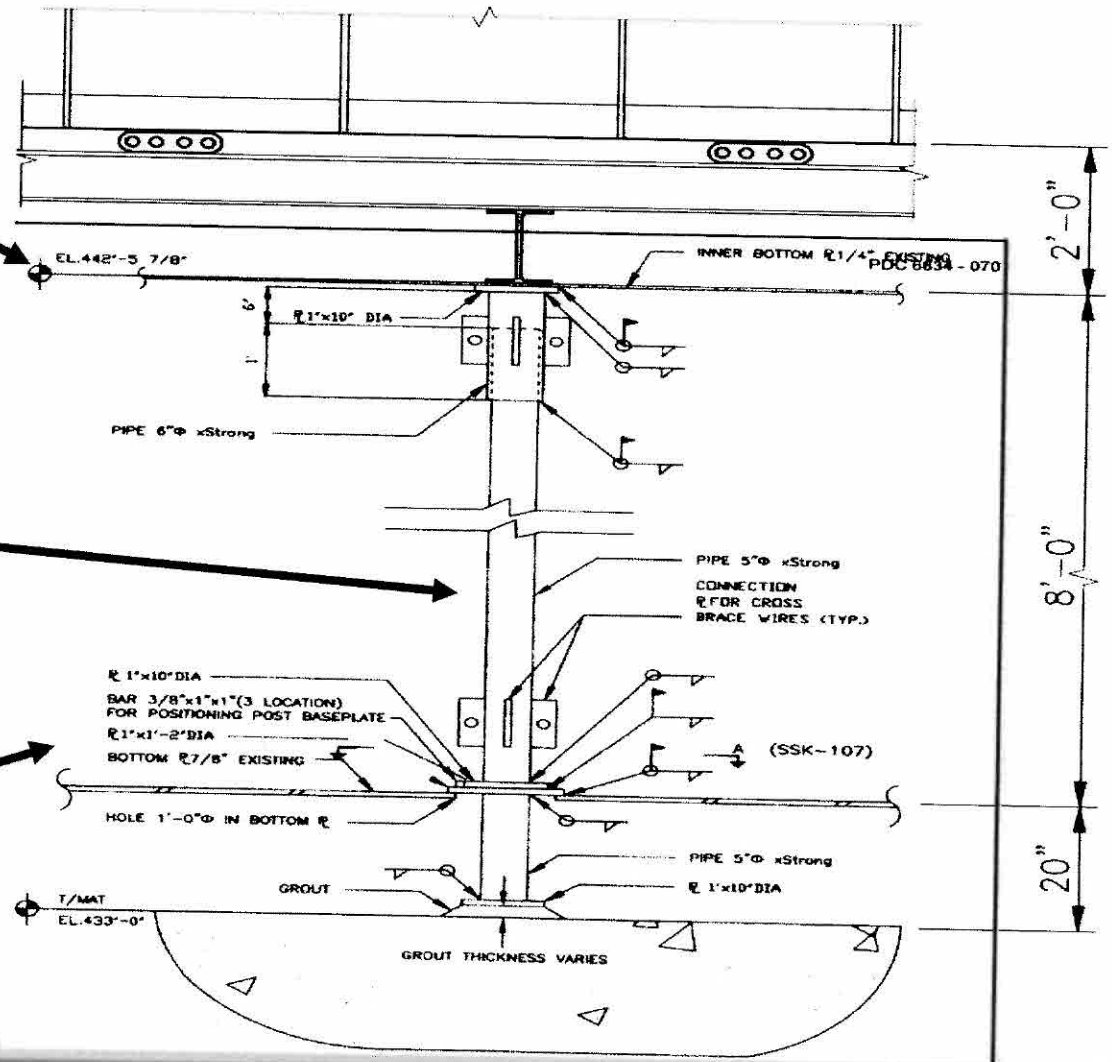
ENERGY NORTHWEST

R-19 Work – Installation of Module Rail Supports & Decon Hotwell

False Floor

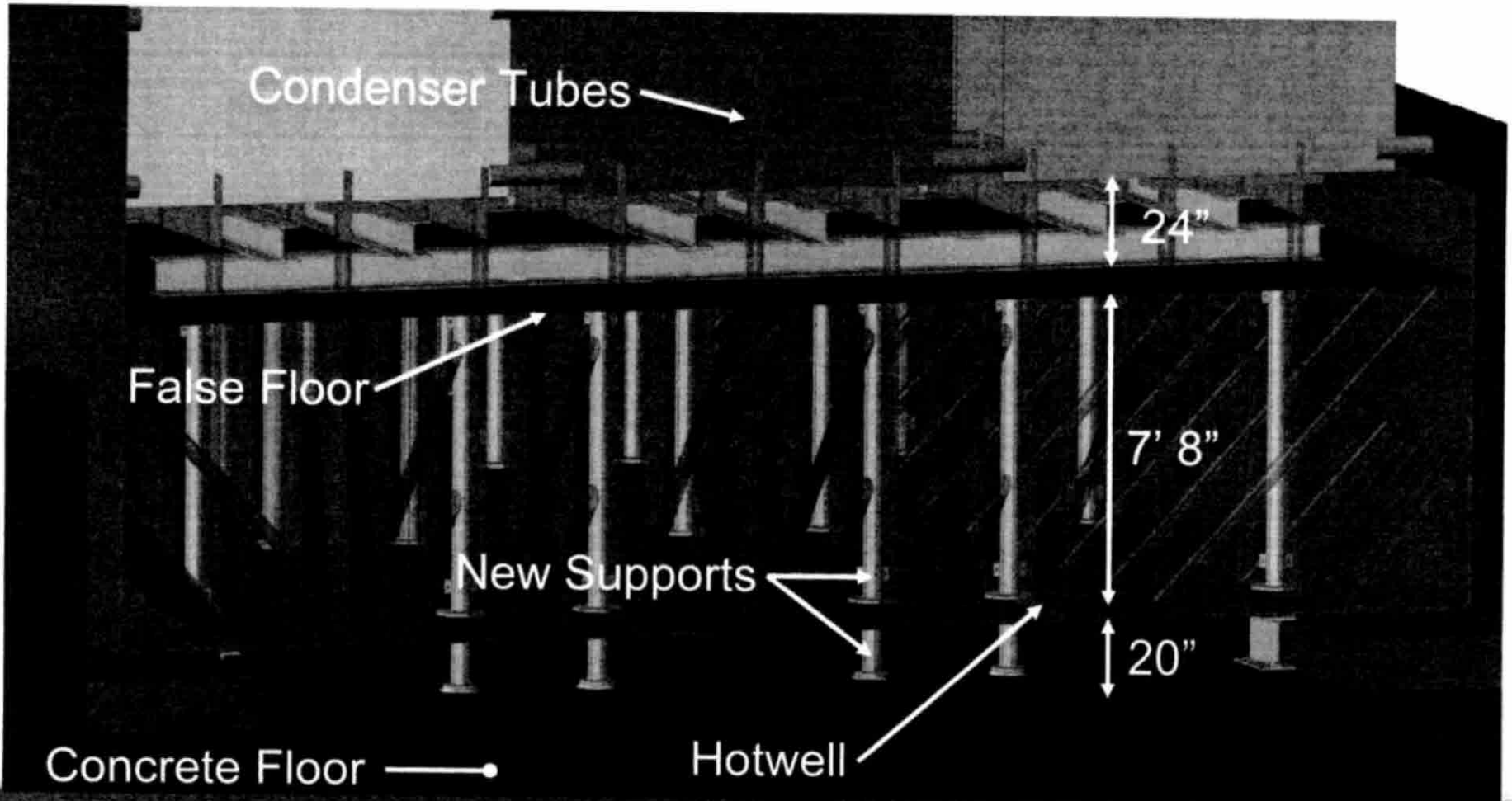
Sketch of a Typical Support

Decon Hotwell



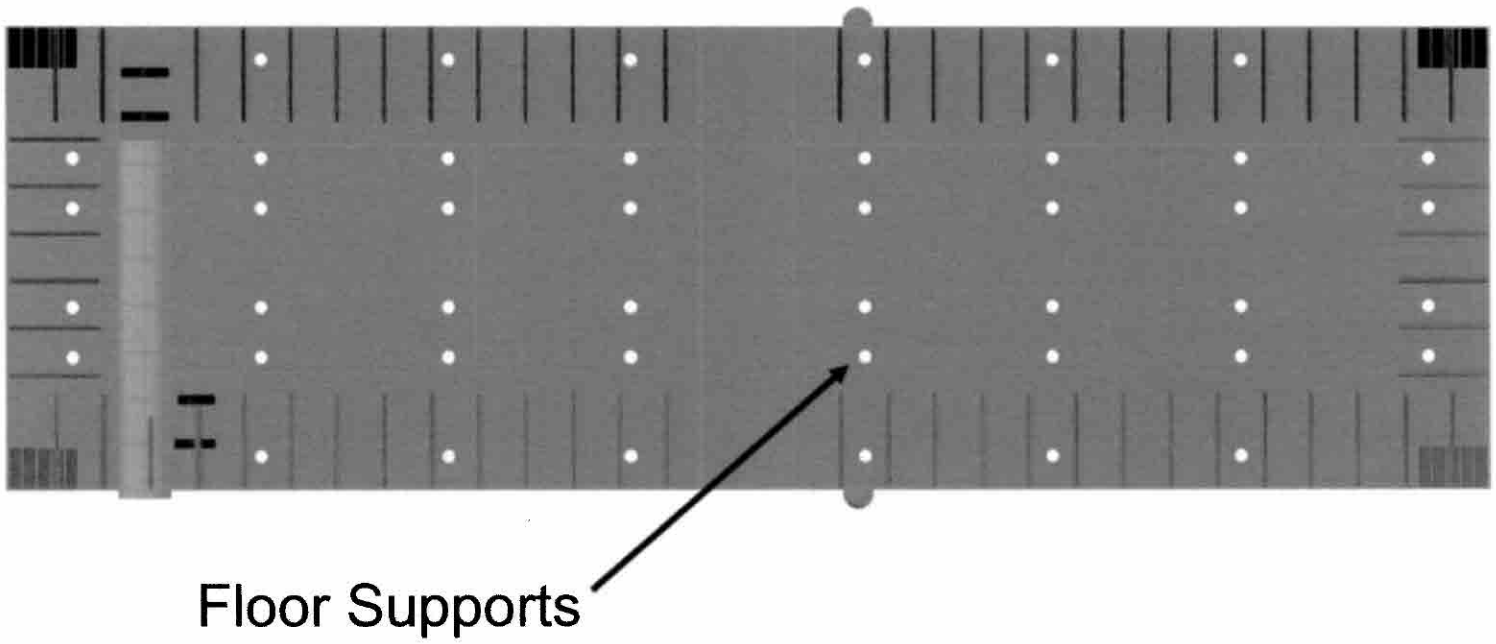
ENERGY NORTHWEST

R-19 Work – Installation of Module Rail Supports



ENERGY NORTHWEST

R-19 Work – Installation of Module Rail supports

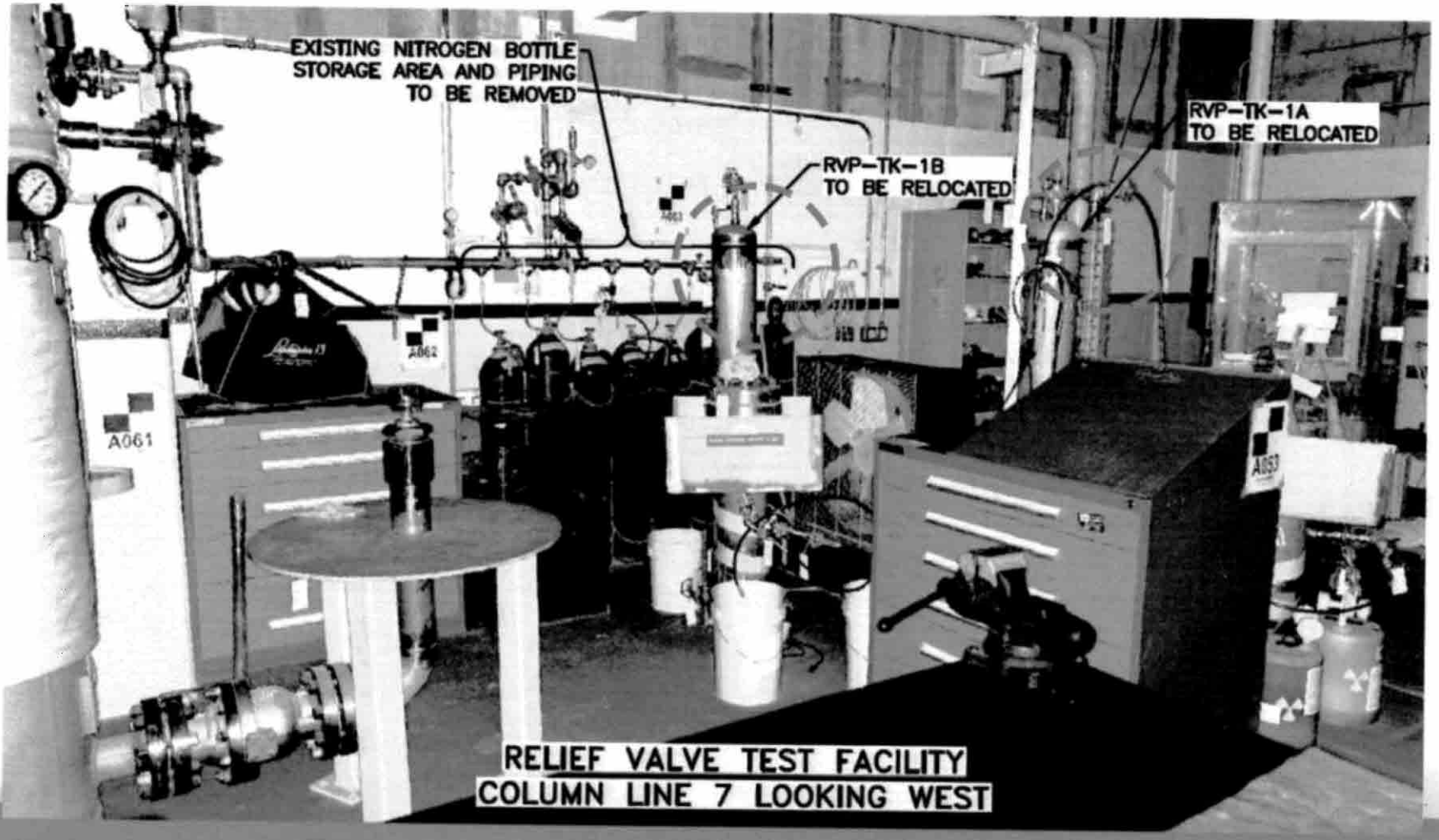


ENERGY NORTHWEST

R-19 Work –Relocate Scaffolding

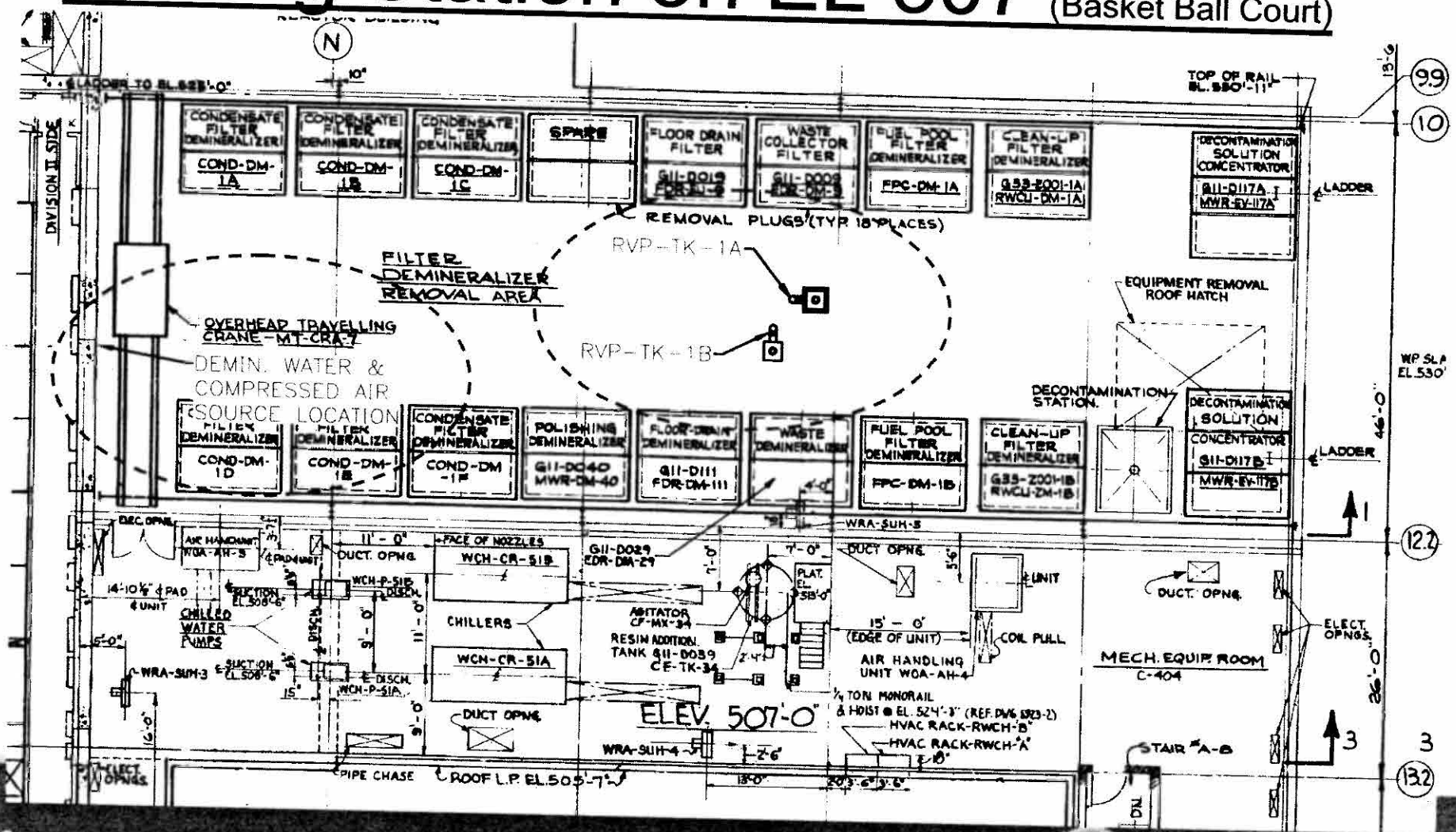
ENERGY NORTHWEST

R-19 Work- Relocation of Valve Testing Station



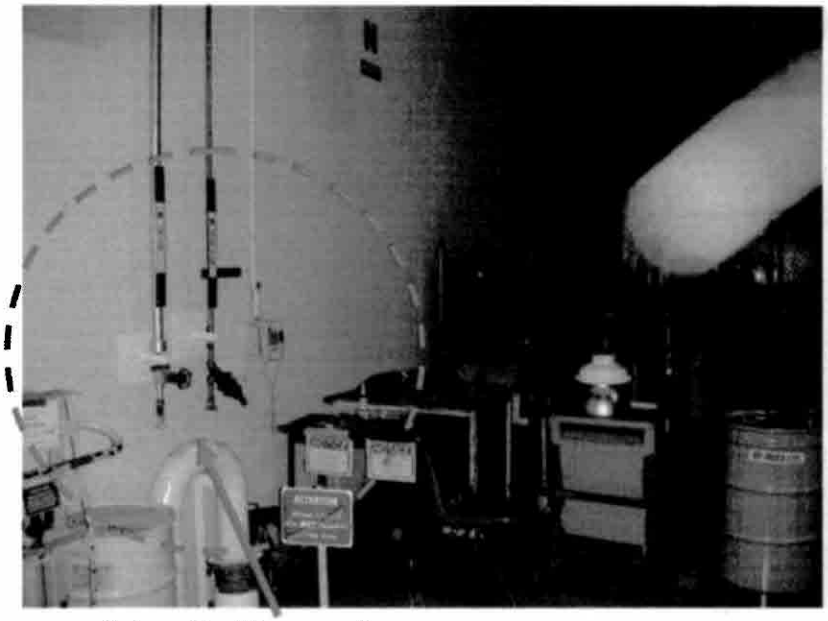
ENERGY NORTHWEST

R-19 Work- Relocation of MOV Testing Station on EL 507' (Basket Ball Court)

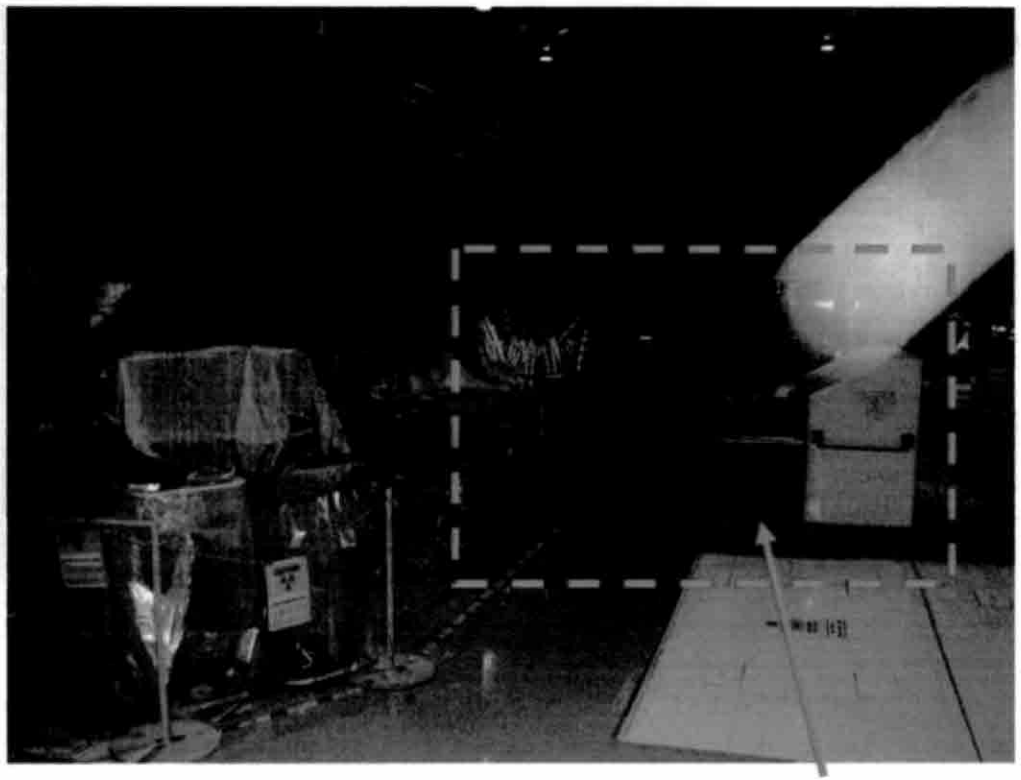


ENERGY NORTHWEST

R-19 Work- Relocation of MOV Testing Station on EL 507'

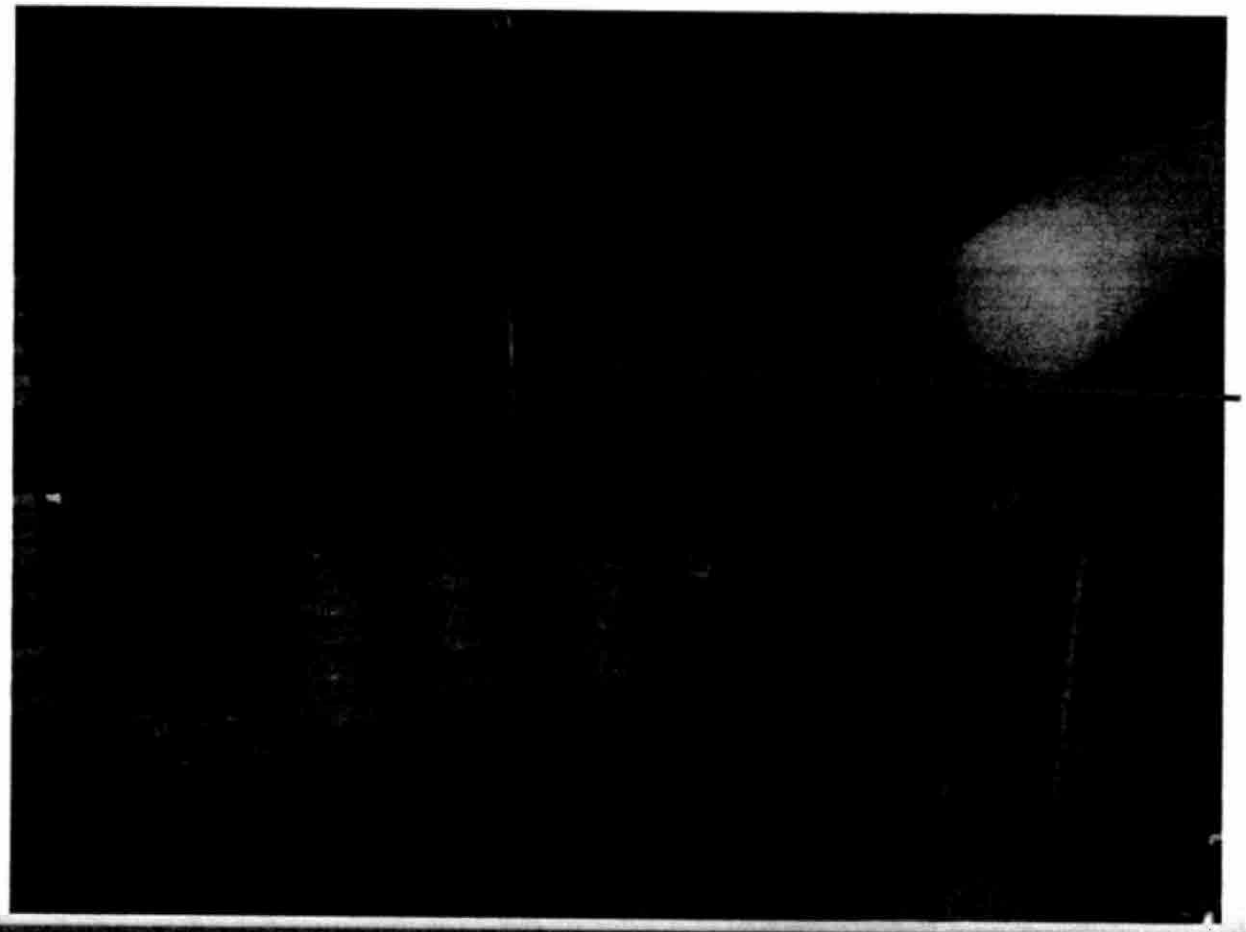


Air & Demin.
Water Supply



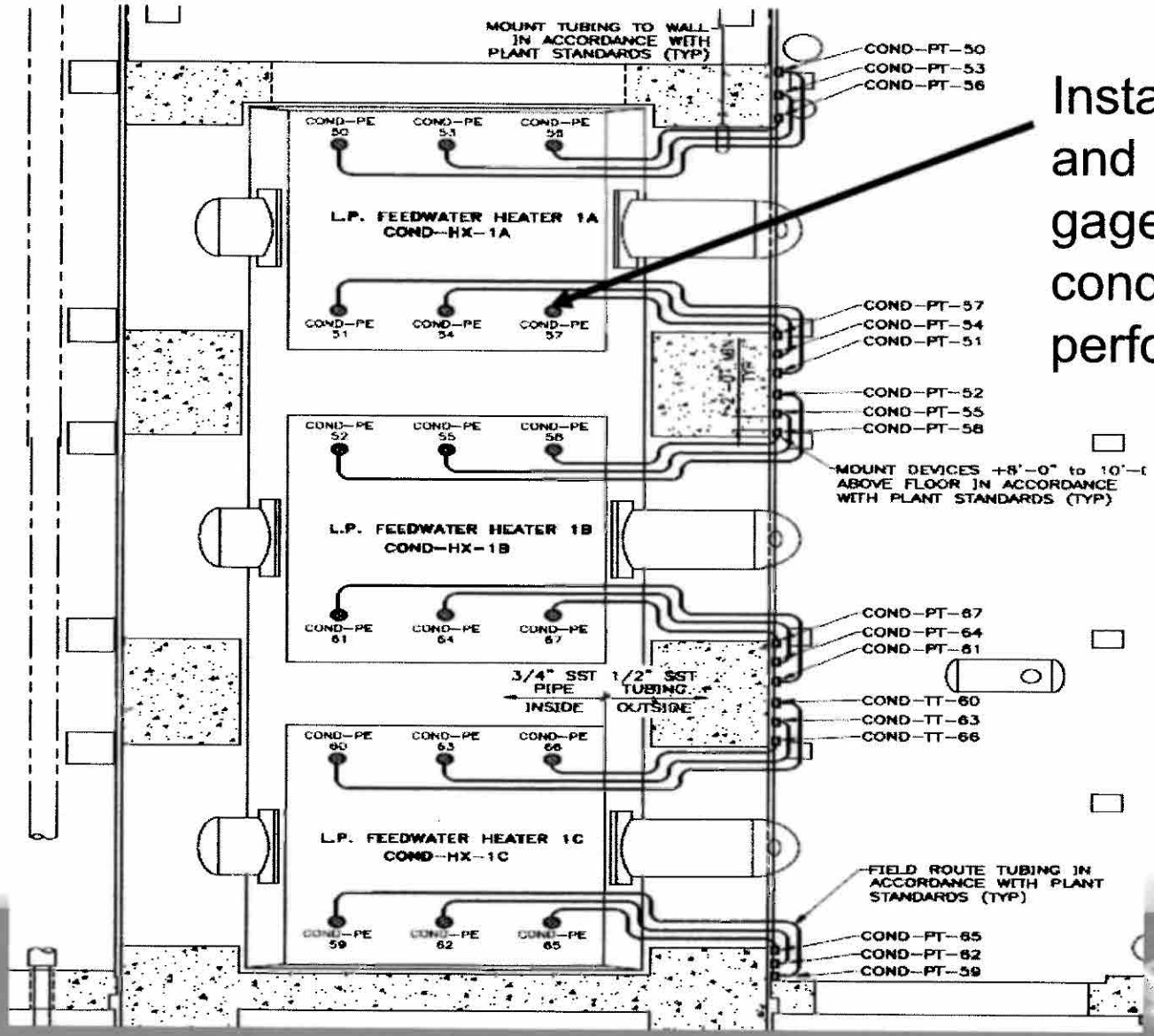
Approx location of test stations

R-19 Work- Relocation of MOV Testing Station on EL 507'



Relocation of scaffolding may be required

R-19 Work- Install Performance Instruments



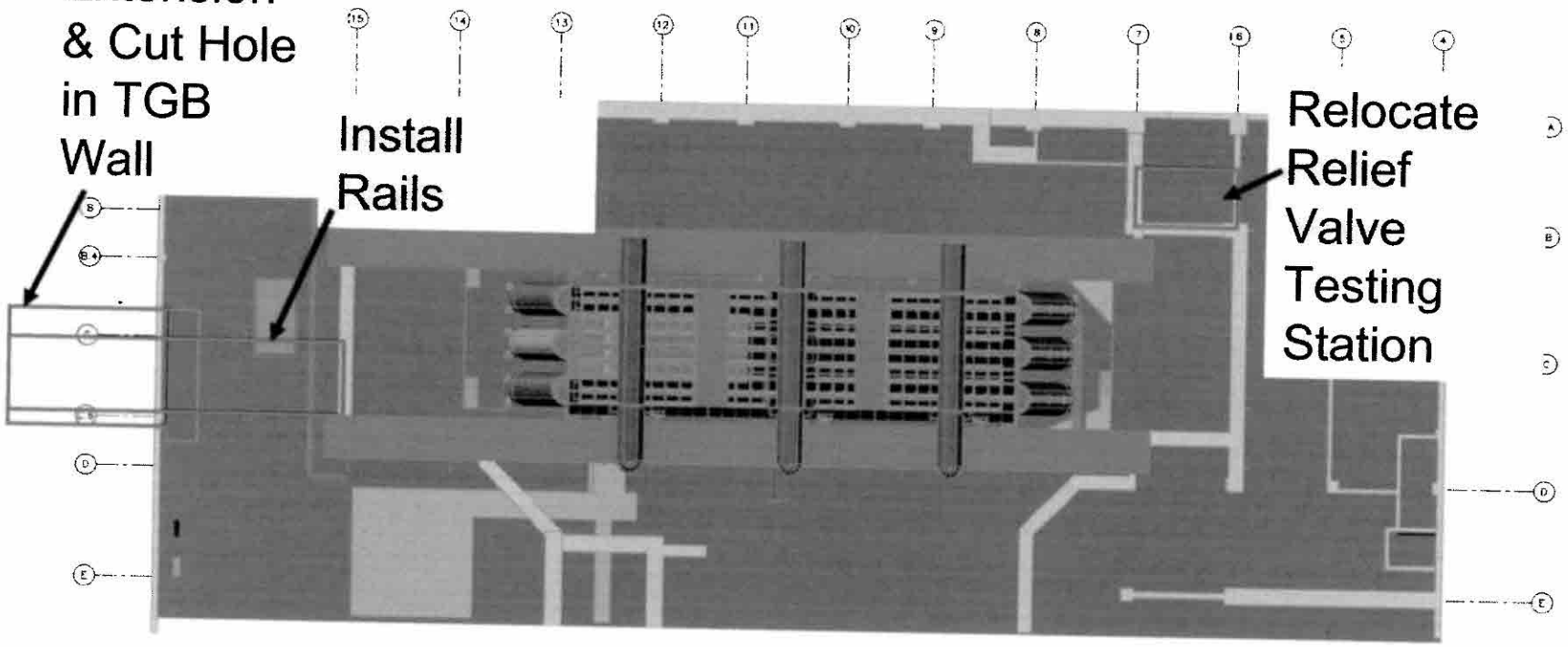
Install temperature and pressure gages to monitor condenser performance

ENERGY NORTHWEST

Cycle 20 Work

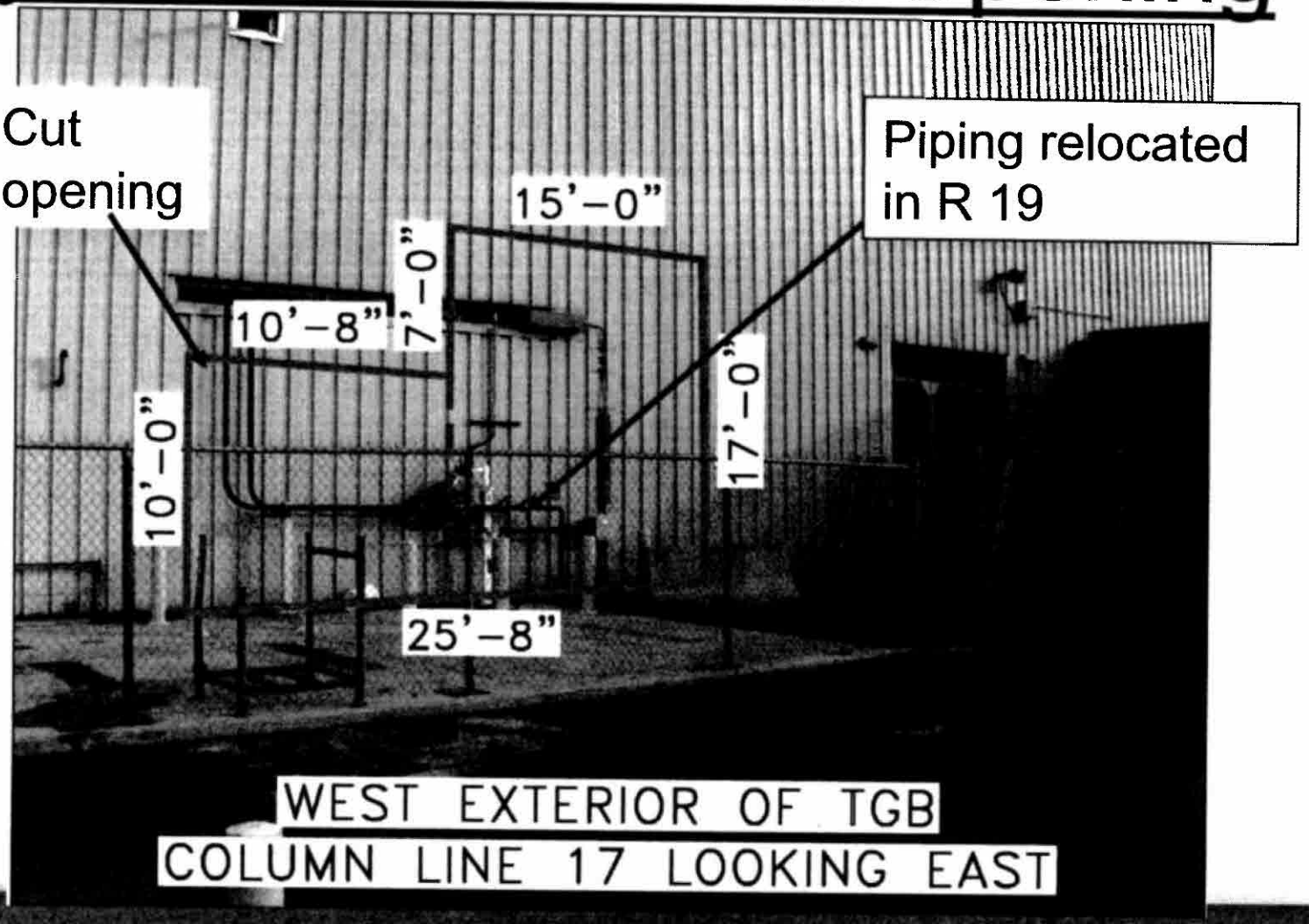
- Installation of RCA extension
- Installation of rails
- Installation of exterior facilities
- Modify security boundaries
- Relocation of relief valve testing station
- Cut hole in wall column line 17 (O/S West TGB)

Affected Areas of Plant for Cycle- 20



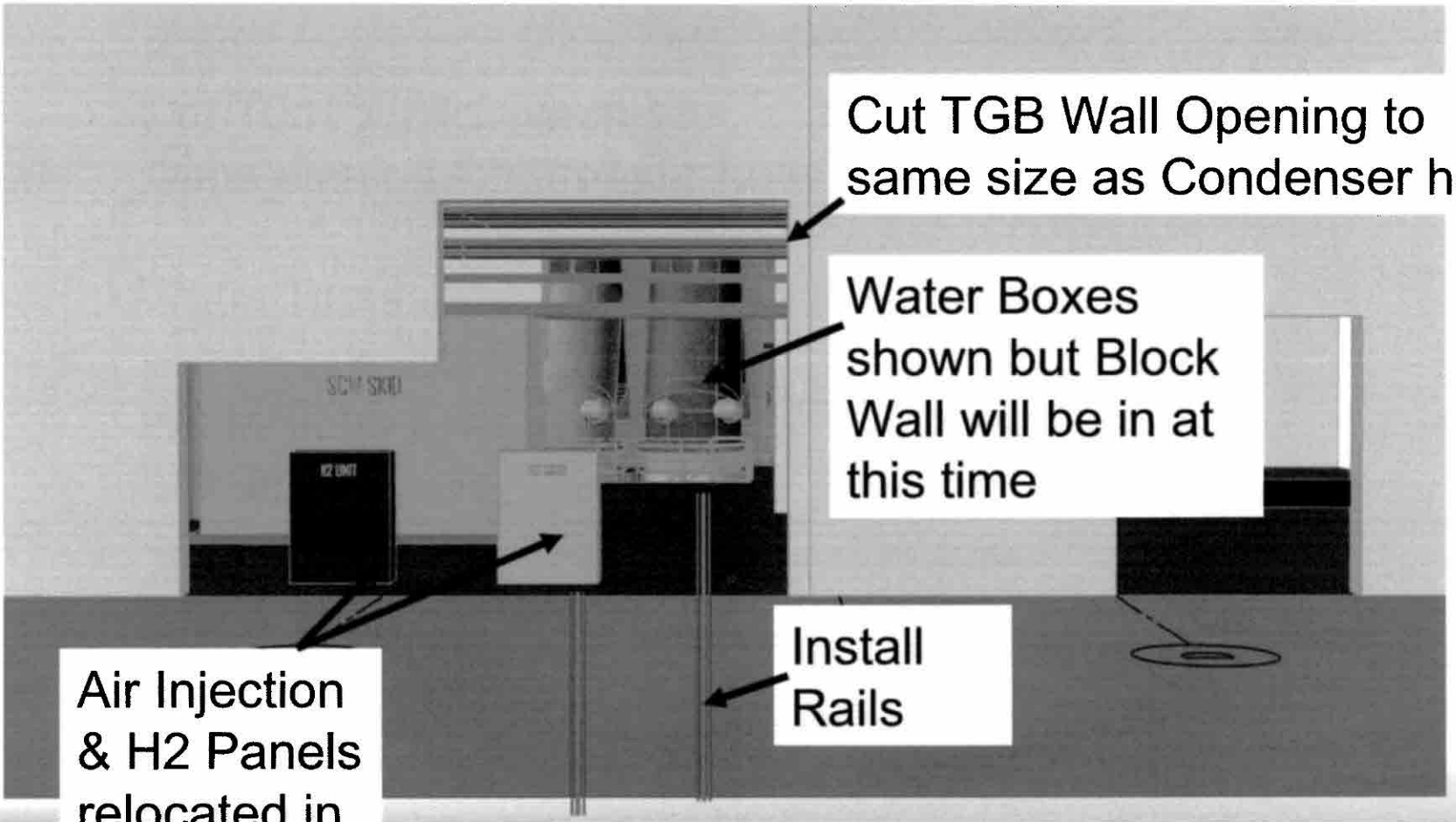
ENERGY NORTHWEST

Cycle 20 Work – Cut Opening



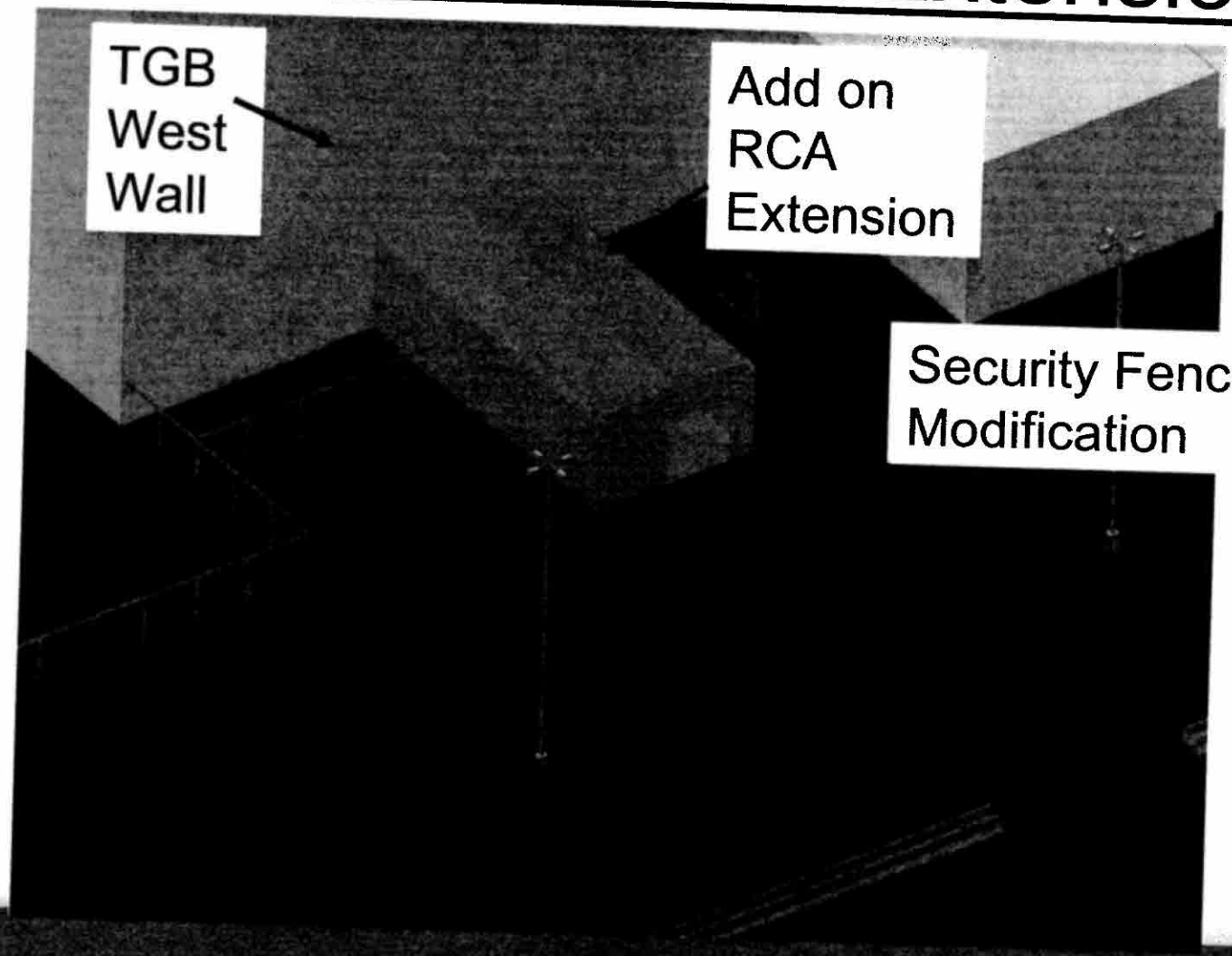
ENERGY NORTHWEST

Cycle 20 Work – Cut Hole in TGB West Wall



ENERGY NORTHWEST

Cycle 20 Work – RCA Extension

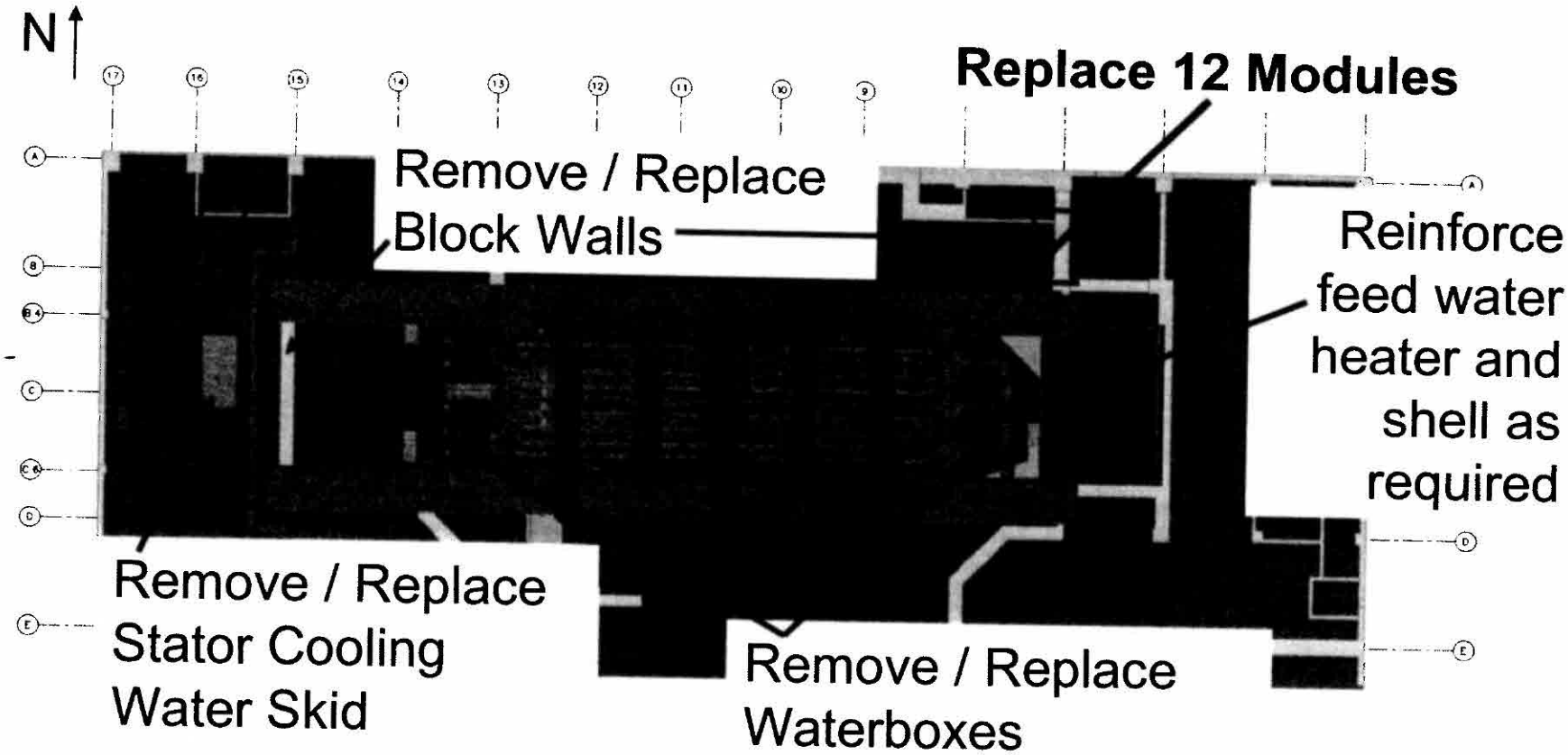


ENERGY NORTHWEST

R-20 Work

- Remove/Replace Block Wall Column lines #7 & #15
- Relocate/re-install Stator Cooling Water Skid
- Remove/Relocate/re-install Water Boxes
- Remove/re-install pathway interferences
- Install / Remove Module Rails and special rigging in the Condenser area
- Remove Old Condenser Modules
- Install New Condenser Modules

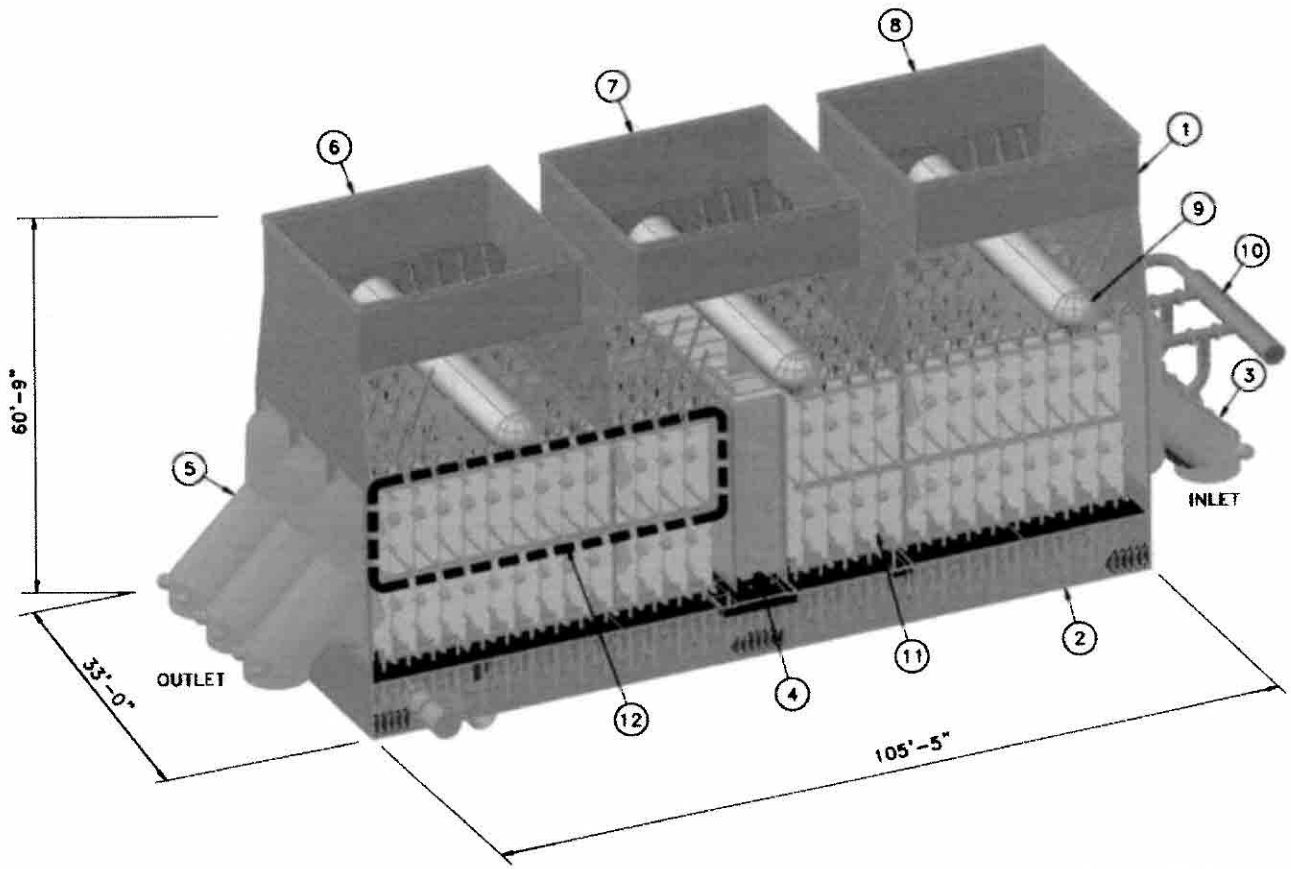
Affected Areas of Plant for R-20



ENERGY NORTHWEST

R-20 Work - Modules

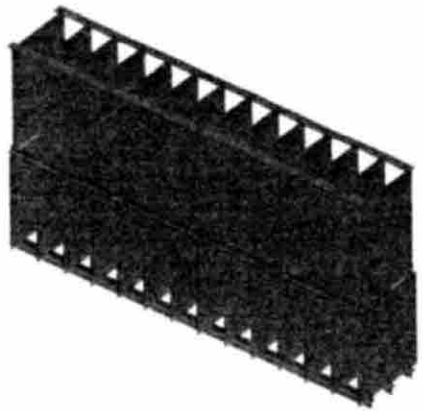
MAIN CONDENSER



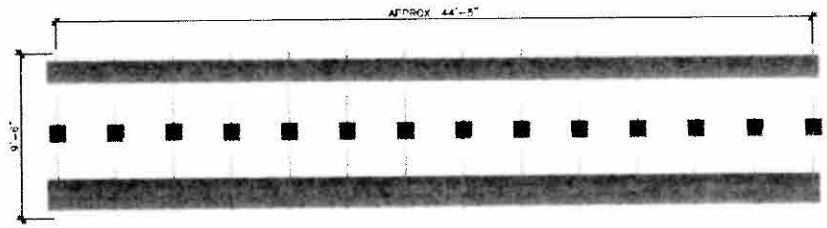
1. CONDENSER SHELL
2. HOTWELL
3. INLET WATERBOXES
4. INTERMEDIATE WATERBOXES
5. OUTLET WATERBOXES
6. L.P. TURBINE EXHAUST NECK 1-C
7. L.P. TURBINE EXHAUST NECK 1-B
8. L.P. TURBINE EXHAUST NECK 1-A
9. FEEDWATER HEATER 1-A
10. AIR REMOVAL PIPING
11. TUBE SUPPORT PLATE
12. CONDENSER MODULE (1 OF 12)

ENERGY NORTHWEST

R-20 Work – 12 Modules

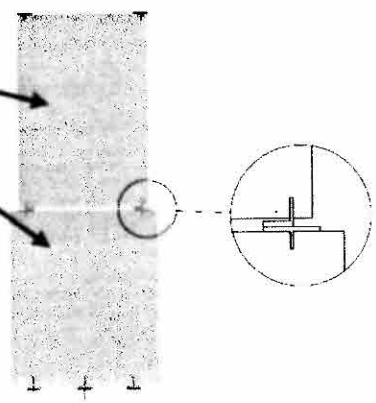


ISOMETRIC VIEW
NOT TO SCALE

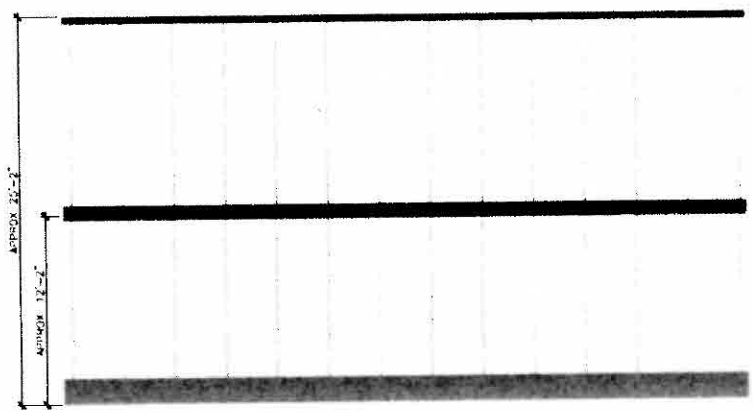


TOP VIEW
NOT TO SCALE

Separated for removal



END VIEW
NOT TO SCALE



SIDE VIEW
NOT TO SCALE

ENERGY NORTHWEST

Cycle 21 Work

- Dispose/Recycle/store (interim) existing modules
- Restore West outside Turbine wall #17
- Remove RCA Extension outside of the West Turbine wall #17
- Remove Temporary Housing
- Complete Work Order closeout
- De-mobilize Contractor
- Close and complete Project

LRP Budget

Input for HURON on 02-01-08 for CGS Condenser Project Business Case						
	Modular Titanium FY08$K					
Description	2008	2009	2010	2011	2012	Total
Procurement						
Procurement of Condenser	$ -	$ 18,000	$ 19,000	$ 2,060	$ -	$ 39,060
Installation						$ -
Internal Labor	$ 650	$ 1,000	$ 800	$ 1,400	$ 200	$ 4,050
External Labor	$ 300	$ 8,200	$ 2,600	$ 17,000		$ 28,100
Design and Project Support						$ -
Security Mods	$ 238	$ 1,917	$ 1,300	$ 1,550	$ -	$ 5,005
Design Packages	$ 2,820	$ 2,200	$ 726	$ 1,880	$ -	$ 7,626
Facilities	$ -	$ 1,250	$ 1,000	$ 1,000	$ -	$ 3,250
In-Processing		$ 1,000		$ 2,250	$ -	$ 3,250
Project Closeout						$ -
Decon/Disposal	$ -	$ -	$ -	$ -	$ 7,000	$ 7,000
Demob and Closeout	$ -	$ -	$ -	$ 757	$ 247	$ 1,004
Taxes						$ -
Washington State	$ 302	$ 2,931	$ 2,216	$ 2,385	$ 652	$ 8,487
Total	$4,310	$ 36,498	$ 27,642	$ 30,282	$ 8,099	$ 108,832
Management Contingency		$ 8,000				

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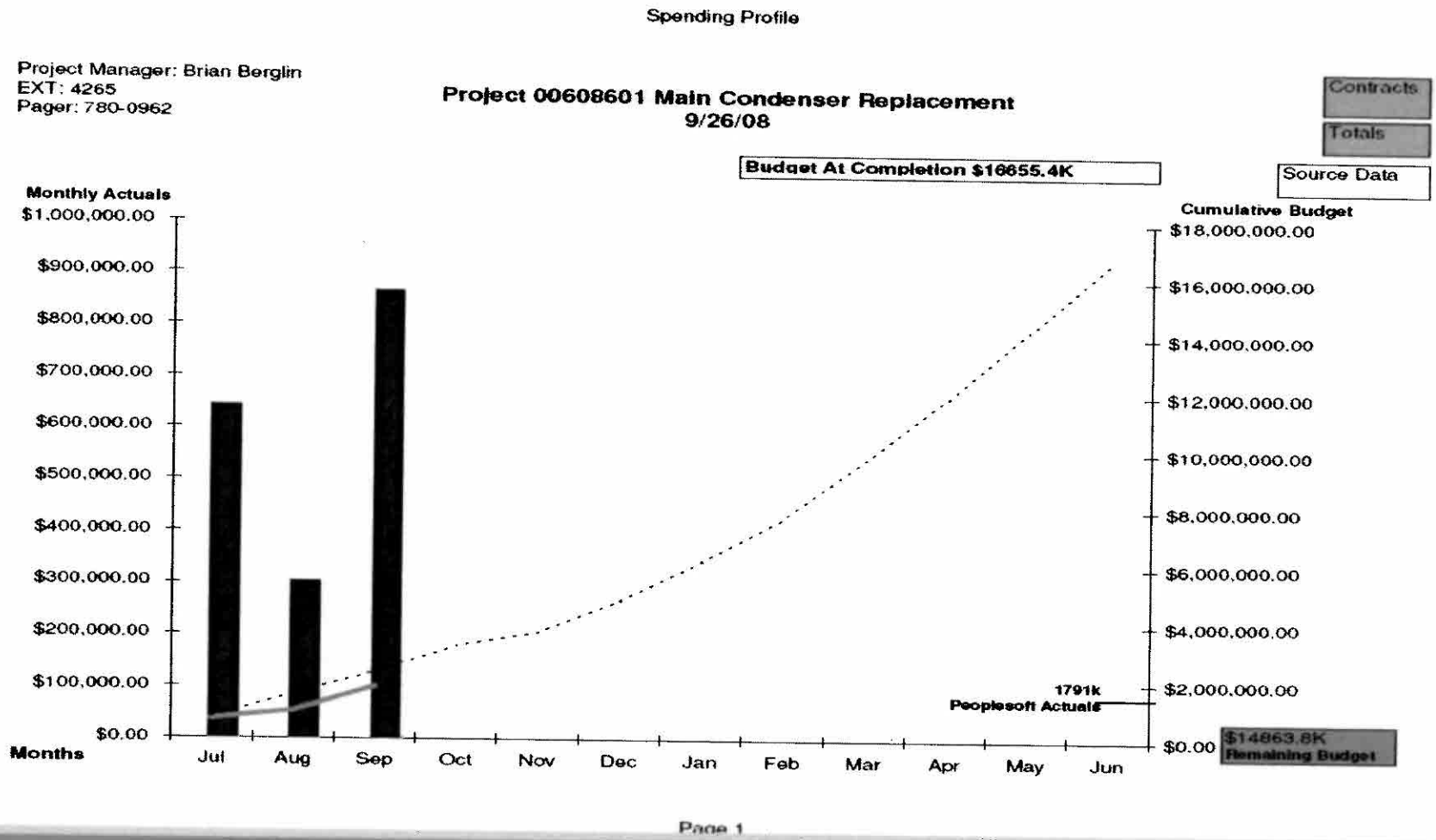
FY09 Cost & Budget



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Project Information Updates

- 30% Design Review for R-19 Performance Monitoring Instrumentation (PDC 6692) completed by WEC on schedule. On track to complete 70% review
- 70% Design review for Condenser Travel Path Interference inside TGB (PDC 6693) on track to complete
- 70% Design for R-19 Condenser Mods to support rail system support & access (PDC 6834) is one week behind schedule. 100% Design is still on track to complete on time
- Relocation of Building 80 warehouse material completed so construction of ½ of the building can commence for the new Fabrication Shop facility
- Project Team benchmarked Laguna Verde Condenser replacement project
- R-19 Outage Project Work Orders are 18% planned

Contract Procurement Status

Activity	Estimated Dates Module	Installer
Issue Request of Proposal	Complete	Complete
Pre-bid Conference	Complete	Complete
Proposals Due	Complete	Complete
Visit Vendors	Complete	
Offeror's Presentations		Complete
Info Memo to the Board	Complete	Complete
Issue Best & Final Offer	Complete	Complete
Best & Final Offer	10-07-08	10-07-08
Issue Limited Notice to Proceed	10-24-08	10-16-08
Action Memo to the Board	11-22-08	10-24-08
Contract Execution	11-25-08	10-30-08

Module Scope -12 Modules w/ requested delivery in 07-2010
Installer Scope - R-19 Implementation, R-20 Pre-outage Design & Install, R-20 Implementation. Mobilization 11-30-08 following Contract Execution.

CGS Main Condenser Upgrade Project

Summary - Energy Northwest has been considering options regarding replacement of Columbia's main condenser. The options include tube material selection, re-tube or modular replacement methodology, and selection of an outage year and outage duration for this effort.

Technical Study: - EN hired consultants Sargent & Lundy (S&L) to identify and evaluate options for repair of the CGS condenser which has been experiencing an increased frequency of leaks. S&L's initial draft was determined lacking by EN in the Oct. – Nov. 2006 time frame, and S&L was requested to improve their report in a number of areas. The report was issued in mid December 2006

Business Case – Six combinations of the above mentioned options were analyzed with total costs ranging from $26M to $81M. A "do-nothing" option was not analyzed although a replacement delay option was included at BPA's request.

Project Approval Process – The S&L report was reviewed by EN staff. EN also prepared several business case analyses based on the results of the report. The project was brought before the Plant Health Committee (PHC), consisting of the Plant Manager and the Department Managers, for action. Option 3, re-tubing with titanium, was selected and recommended. The Executive Authorization Committee (EAC) consisting of the CEO and Vice Presidents reviewed the recommendation on 1/31/07 and approved proceeding with option 3.

EN has not yet notified the Executive Board of this decision – they probably will in the February meeting.

Where Do We Stand? – The main condenser upgrade project has been approved by EAC for the option to re-tube using titanium material for a total estimated cost of $30.6M. At this point the project has not been formally presented to or approved by the Energy Northwest Board. They will probably notify the Board in the February meeting. Board approval will probably occur in the context of Board approval of the FY-08 budget in April, as the project will be listed in the budget and dollars included for it.

According to Vic, INPO again mentioned the need for EN to do something about the condenser (implied replacement). Vic, Dale and Scott all believe that condenser replacement is a reliability issue and a radiation exposure issue that needs to solved now, without delay.

BPA Involvement – BPA's involvement has been limited by Energy Northwest. We have not been allowed to any input in the Sergeant and Lundy scoping report. Our request to attend review meetings with senior managers was denied. We did have two good meetings with the Project Manager and his support team, and a third meeting to discuss the business case analysis. We also attended the PHC and EAC meetings described above. We are still looking at the information and the cost benefit analysis.

BPA PGC position – We agree that at some point, the condenser will have to be replaced. But, serious consideration should be given to reconsideration of the delay option (6 to 8 yrs) following the 1) condenser eddy current testing and condition assessment; and the 2) fuel inspections, scheduled for the upcoming outage. A delay of the retubing option would help assure that the new condenser would last until 2043 (with life extension). It would also postpone the expenditure of significant dollars in this rate case (historically, EN's major project estimates have been optimistic).

PGC is preparing a letter to EN with a list of questions that we would like formal answers to, in order to ensure we understand the basis of EN's decision and ensure we have EN's official company position relative to the questions. Answers to these questions will help validate our current thinking.

BPA has not yet been asked to provide an approval or non-disapproval of the project. We could ask for an official letter requesting our approval, or take our non-disapproval action via the FY-08 budget action as the project will be listed in the budget and dollars included for it.

Option Summary – Pros versus Cons.

PRO	CON
Delay Re-tubing for 6 years (until 2013) $30.6M	
• Would help ensure new tubes last until end of plant life (2043 assuming life extension). • Full eddy current test and tube plugging scheduled for the May outage – should result in a 'tight' condenser. • EN has significantly improved it's ability to find and repair tube leaks if they occur.	• Could experience several down powers per year to plug leaking tubes results in lost generation to BPA and increased radiation exposure to EN employees. • Would result in increased friction between EN staff and Executive Board with BPA. • Would result in lower performance rating of CGS by Industry peer groups, i.e. INPO, WANO.
Re-Tube vs. Modular Replacement $80.9M	
• Modular replacement would increase generation current generation by 91,000 MWH at present power levels through increased efficiency. • Modular replacement could support an extended power up-rate. • Fewer tube sheet technical issues to deal with as compared to re-tubing and it removes more copper from the system versus re-tubing (removing copper tube sheet 1% gain).	• Modular replacement capital costs are $50M higher than re-tube. • Modular replacement results in a significantly longer outage to install (120 days vs. 68 days for re-tube). • As part of a future power up-rate, other plant modifications could be explored to reduce the amount of de-rate associated with re-tubing.
Re-tubing with Titanium $30.6M	
• Better efficiency than stainless steel, less de-rate. • Titanium supports current testing technology for leaks. SS is difficult to test. • Lower capital cost than modular replacement and shorter outage time.	• Some de-rate at current power levels (< 1 FPD/yr) as compared to modular replacement. • Some tube sheet issues to deal with, i.e., cathodic protection, sealing the tube sheet joint, increased annual inspection of tube sheet coating, extra down powers for repairs.

Oct 7, 2004
EN News

The AST submittal was a key milestone for a Plant Top Priority regarding "Completeness and Accuracy of Staff Work." Commenting on this accomplishment, Robin Feuerbacher, Manager, Reactor/Fuels Engineering, said: "In 30 years, this is the toughest challenge I have seen placed on a project team to complete complicated analyses under the utmost quality and demanding schedule requirements. The individual efforts by all of the AST project team members and external contractors were tremendous. Many thanks to all who supported this effort, including internal and external experts involved with the reviews."

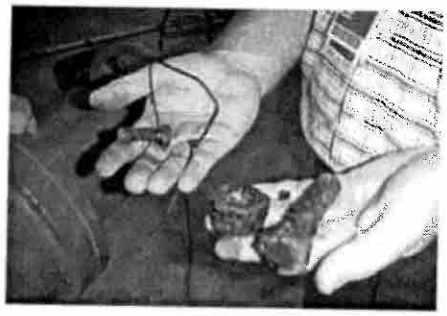
Condenser tube leaks and the Circ Water System

Matthew Hummer, System Engineer

In the past, when you have heard about tube leaks in the main condenser that resulted in plant downpowers or shutdowns, did you think of the Circulating Water System (CWS)? Even now do you think that most of the recent tube leaks might have been caused by foreign material wearing through the tubes rather than by steam damage to tubes? If you have answered "NO" to both of these questions then you are not alone.

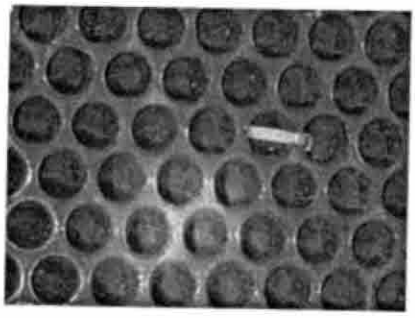
A root cause analysis was performed under PER 204-0811 for the most recent downpower (May 2004) to repair a condenser tube leak on-line. The root cause for this tube leak was determined to be fretting wear on the tube due to foreign material. When you think of foreign material you probably think of our FME practices employed with opening up of normally closed piping systems or other plant components during maintenance activities.

What you may not realize is that with all its piping the CWS is an open system. The cooling towers, CW Pump basin outside the Wind River Building, and some openings inside the Wind River Building, are all points of entry for foreign material that are not necessarily associated with maintenance activities. What this means is that anything dropped in these locations has the potential of ending up in the main condenser and challenging the integrity of the condenser tubes.



Tumbleweeds, caution tape, plastic bags, cooling tower components, hammers, and even a duckbill have all been found in the condenser. Screens are installed at the suction of the CW Pumps, but gaps in the screens were found during the recent forced outage. The gaps were repaired before starting up and the screens are inspected and repaired during every refueling outage. This will prevent large items (such as a duck) from entering the condenser.

Very small (less than ½") items can eventually work through the screens. If you compare the image of a hammer banging around on the condenser tube sheet to the image of something small like a tie wrap, you would probably conclude that the hammer would cause more damage. That is not the case! The tie wrap is almost guaranteed to cause a tube leak while the hammer will cause little or no damage to the tubes. How can this be? The tie wrap will become lodged in the area between two tubes (called the ligament) and CW flow will cause it to wiggle around. That wiggling plastic tie wrap will wear through a metal tube. Analysis of a tie wrap that caused a tube leak showed that the plastic tip picked up metal particles from the tube during this rubbing or fretting. The result was that the tip of the tie wrap hardened. This turned the tie



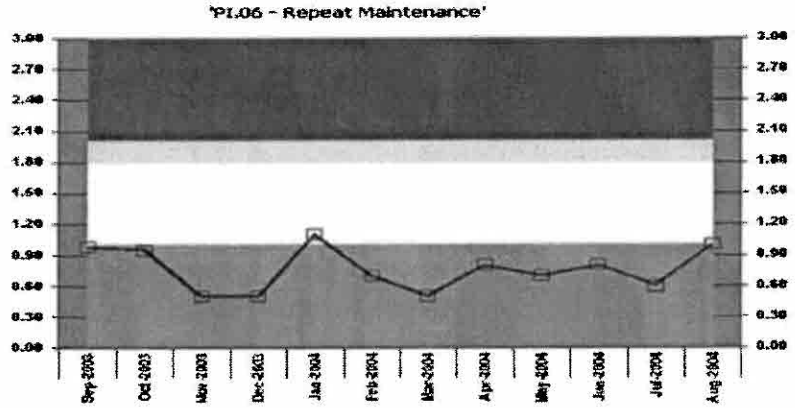
wrap into a miniature chisel that wore through the tube which is a softer metal (brass).

The Foreign Material Program is evaluating FME controls for the CWS, Wind River Building, and cooling towers as part of corrective actions for Root Cause 204-0811. The FME controls will result in changes like Work Order precautions, and signage changes to the Wind River Building and Cooling Towers to help remind people to be aware of FME controls for the CWS.

If you go out to visit the cooling towers you should be aware that anything you drop will eventually end up on the screens or in the condenser. Even though you are physically removed from the plant an errant tie wrap could shut it down. Please use appropriate caution around the cooling towers and Wind River Building to keep these tie wraps and other objects (including ducks) from challenging the integrity of the main condenser tubes.

Repeat Maintenance

- **Excellence = Less than 1% of total maintenance needs to be re-performed within 12 months of being returned to service.**



- **GAP = None**
- Enhancements:
  - Security Upgrades (microwave, CPUs, x-ray & explosive detectors) will eliminate 20%
  - CR 2-04-05389 will evaluate methods to reduce leaks after maintenance activities, an 8% contributor

Station rework indicator shows success

Don Merhar, Maintenance Support Manager

Performance indicators at Columbia Generating Station are usually brought up to demonstrate where performance improvements are necessary. The station rework indicator is a little appreciated or understood success story.

Maintenance Instruction 1.9.1 defines Rework as work that has to be redone on a system component due to a failure in the work process, personnel error, testing, or results in system component failure within 12 months of becoming operable following maintenance. Rework and Repeat Maintenance are synonymous terms.

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Condenser Replacement Project Review

Project No. 00608601

June 23, 2008

Brian Berglin

Agenda

Welcome	Berglin / Gambhir	10 min
Introductions	All	15 min
Business Case	Indall	10 min
Conceptual Study	Grier	10 min
Benchmarking	Berglin	5 min
3-D Animation	Berglin	10 min
Project Big Picture	Berglin	10 min
Break		10 min
Project Controls	Jordan	10 min
Module Procurement	Woods	10 min
Design Changes	Grier	15 min
Condenser HIT / Scope R-19	Lovejoy	10 min
RP / ALARA	Garza	10 min
Procurement Overview	Whelan	10 min
Facilities	Berglin	10 min
Risks	Berglin	10 min
Lunch		30 min
Questions / Answers	All / Team	45 min

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Purpose and Take Aways

- Communicate Project
  - Scope
  - Status
  - Risks
- Take Aways
  - Station awareness
  - Your Support (How you can help)
  - R-20 Implementation (It's Happening!)

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Business Case: Issues and Observations

Five major issue areas are impacted by Main Condenser performance.

Issue Areas	Summary Observations
Fuel Integrity	• Copper content in the existing condenser tubes poses a continuing risk of fuel cladding damage and fuel failure events.
Radiation Exposure	• Copper from the condenser contributes to increased plant radiation exposure. • Plant downpower evolutions to repair leaking condenser tubes increase radiation exposure. • Copper from the condenser contributes to additional decontamination activities and increases costs. • Potential future litigation due to radiation exposure to workers.
Operational Reliability	• Recurring condenser tube leaks have impacted plant operation and output by forcing downpower evolutions to repair tube leaks.
Financial Implications	• A result of downpower evolutions, forced outages, increased dose, additional decontamination activities, and lost plant generation CGS costs have been adversely impacted.
Industry Perspective	• The potential for fuel damage resulting from copper corrosion is a high interest issue within the nuclear industry and CGS is lagging the industry in this area.

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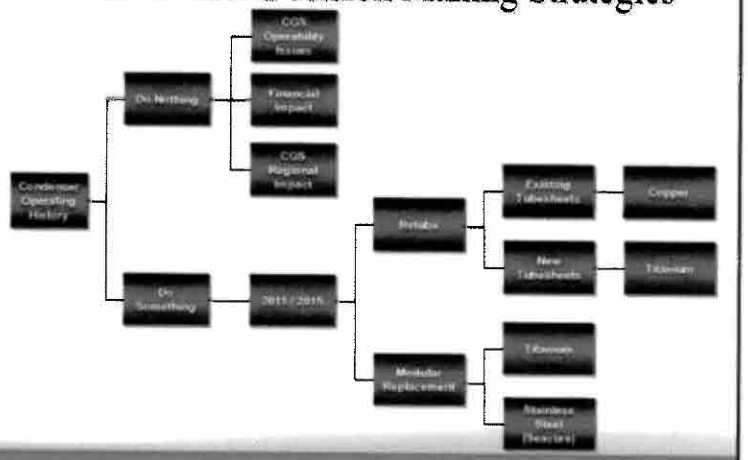
Condenser Decision Making Strategies



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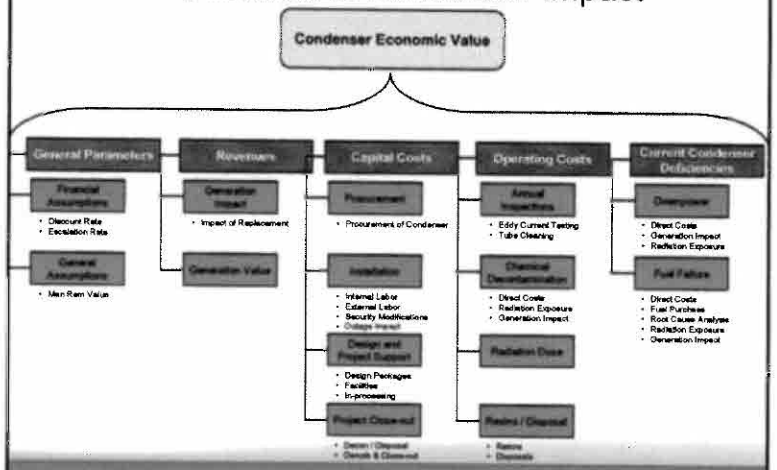
Overview of Condenser Impact



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Do Nothing Strategy

The "Do Nothing" strategy is not considered viable for the following reasons:

- CGS operability issues:
  - The continued risk of fuel damage.
  - Loss of generation due to tube leaks and design problems.
  - Unacceptable radiation exposure.
- Financial impact
  - Continuing cost impacts estimated at $162 million (2008$) over the 2008 to 2024 timeframe.
- Regional impact
  - If CGS is not operable, the region would need to replace approximately 1,200MWe of generation capacity

In lieu of the above, CGS has to do "something" with its Main Condenser.

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Strategies Not Considered Viable

Two of the four identified strategies were not considered viable:

- Copper Retube using Existing Tubesheets:
  - Substantial costs associated with the addition of deep bed demineralizers, and;
  - Condenser design issues are not corrected.
- Stainless Steel (Seacure) Modular Replacement
  - Stainless steel tube defects are difficult to detect during the manufacturing process,
  - In-service Non Destructive Evaluation (NDE) methods are inadequate to detect tube cracking,
  - Stainless steel introduces tramp cobalt into the system, increasing radiation;
  - Annual inspection and cleaning costs are significantly higher.

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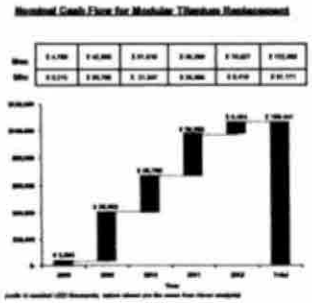
Titanium Modular Replacement in 2011



	Titanium Retube w/ New Tubesheets 2011	Modular Titanium 2011	Delta between cases
Generation Value	$ (12,800)	$ 118,300	$ 131,100
Project Costs	$ (76,708)	$ (93,891)	$ (17,183)
Operating Costs	$ (14,201)	$ (18,800)	$ (4,599)
RPW & RWCU	$ 13,143	$ 13,143	N/A
NPV	$ (90,564)	$ 18,852	$ 109,216

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Business Case Conclusions

- Technical, economic, and regional impact factors drive the need to replace the Main Condenser by 2015.
- The Main Condenser has a direct and significant bearing upon the operability of CGS.
  - Based upon analysis performed on the current condenser, reliable operation after 2015 is uncertain.
  - If the issue is not addressed in a timely manner, the region will need to replace approximately 1,200 MWe of CGS generation capacity with some other resource.
- Pursuing a Main Condenser strategy in 2011 is financially more advantageous than doing so in 2015.
- There are two viable strategies for condenser replacement:
  - Titanium Retube with New Tubesheets
  - Modular Titanium Replacement

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Business Case Conclusions (continued)

- Several technical and operational benefits favor Modular Titanium Replacement over the Titanium Retube with New Tubesheets.
- On a Net Present Value (NPV) basis, the value of the Modular Titanium strategy in 2011 is approximately $109 million more favorable than the Titanium Retube with New Tubesheets strategy in 2011.
- On a stand-alone basis the Modular Titanium strategy results an NPV of $18.7 million.
- The best technical alternative is also the best financial alternative.

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Main Condenser Conceptual Study

- Evaluate potential options associated with modular bundle replacement and identify issues requiring further action
- Issues identified
  - Security
    - Main road additional access lanes at security check point
    - Expand site access facilities (PAP/PAAP) to accommodate the additional ~400 personnel
    - Additional blast resistant enclosure (BRE's)
  - Modular or demolition/removal of the existing condenser modules
  - Single or double stacked module installation (removal)
  - Temporary RCA structure on west side of Turbine Building needed for contamination control

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Conceptual Study (continued)

- Issues identified (continued)
  - Is sand blasting and coating of the water boxes needed?
  - Do the east end water boxes need to be removed from the Turbine Building?
  - To what degree does the Stator Cooling Water (SCW) skid need to be relocated?
  - Will existing condenser modules be recycling or disposal of?
  - The MOV rebuild station (R19 & R20) and the Relief Valve test facility (Cycle 20) must be relocated
  - Selection of the new condenser module vendor ASAP
  - Selection of the installation contractor ASAP
  - Fabrication facilities required for the installation contractor (location, size, content)

yes, will come this o provide space.

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Benchmarking

- Peach Bottom Nuclear Plant (BWR) — 1991 - Corp did BWR that this ~5? days
- Ft Calhoun Nuclear Plant (PWR)
- ValTimet (Titanium Tube supplier)
- TEi (Module Fabricator)
- YUBA (Module Fabricator)
- Ameritie (Titanium Tube supplier)

Laguna Verde replacing their condenser this year → will benchmark their project.

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3-D Animation

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Big Picture

- Project Team
  - Steering Committee
  - Project Management Organization
  - Condenser HIT Team
  - Communication Plan
  - Weekly Project Status Report
  - Weekly Project Action List
  - Monthly News Articles
  - Monthly Meetings with Steering Committee
  - Condenser website (external communication)
- Risk Management (example)

Org chart

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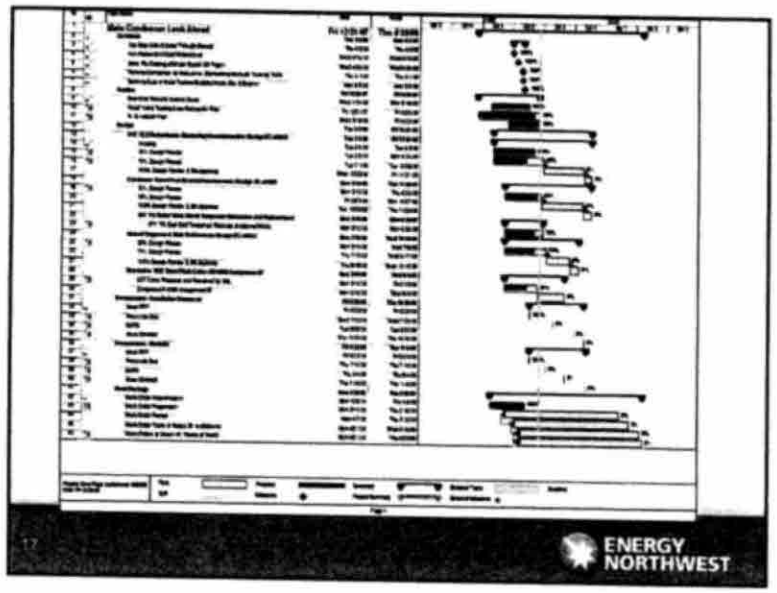
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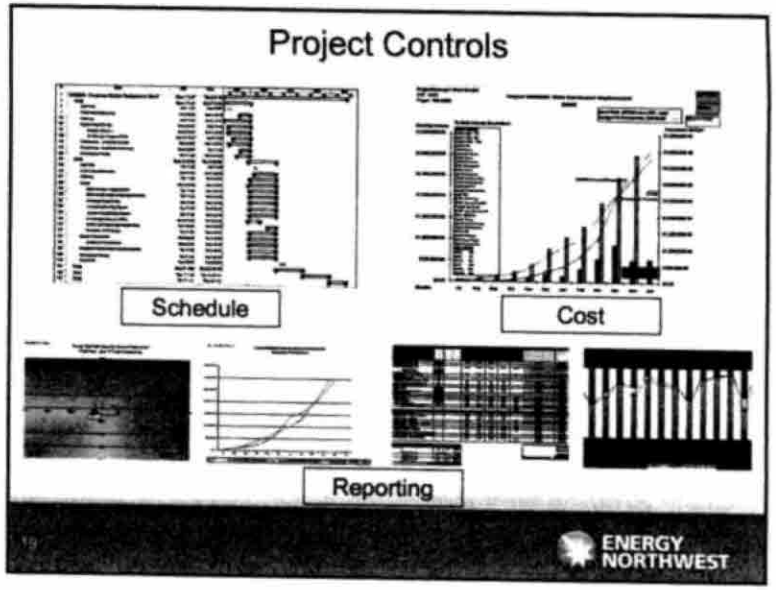
Project Controls
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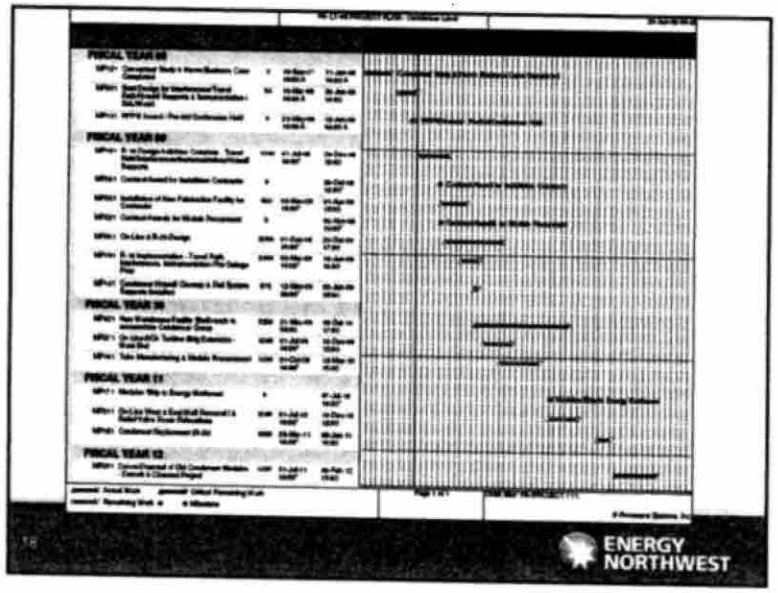
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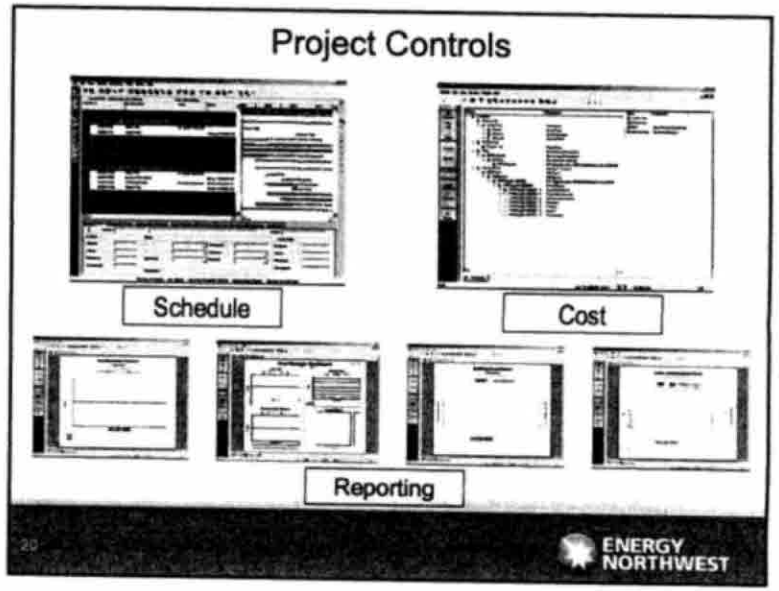
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Levi Woods

Condenser Module Procurement Goal

- 60 Year Design Life
- Achieve 85% or greater Condenser Cleanliness
- Minimize Subcooling
- Minimize Backpressure

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Twelve (12) Condenser Module Design

- **Minimize Turbine back-pressure**
- **Maximum condenser thermal performance**
- **Minimize air blanketing of the tubes and to maximize removal of noncondensable gases**
- **Ensure the condensate temperature depression during operation is no greater than 3 deg F below the saturation temperature in the High Pressure compartment**

— don't want condensate too cold.

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Module Supplier's Main Scope Of Work

- **The Suppliers are responsible for the design, analysis, fabrication and delivery of:**
  - **Twelve (12) factory assembled Condenser Modular Bundles**
  - **Three (3) Intermediate Waterboxes**

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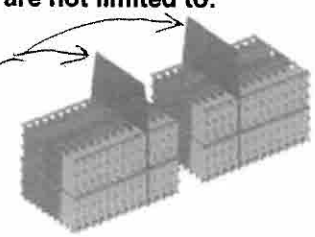
Twelve (12) Condenser Modular Bundles

Module components include, but are not limited to:

- **Welded Titanium tubes**
- **Solid Titanium Tubesheets**
- **Support Plates**
- **Partition Plates**
- **Modular Frame**
- **Reheat Hardware**
- **Internal air removal piping**
- **Cathodic Protection System**
- **Baffle plates and Other impingement protection**



Partition Plates one for LP turbine zones

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some will need to be moved
" " " " " replaced.

Three (3) Intermediate Waterboxes

- Possible Shortening of Waterboxes to increase effective tube length (Shell modification required) → of FWH
- Internal epoxy coating
- Additional Sparger line for train B
- Safety Pad Eyes — on intermediate water boxes.
- FW Heater Support Framing

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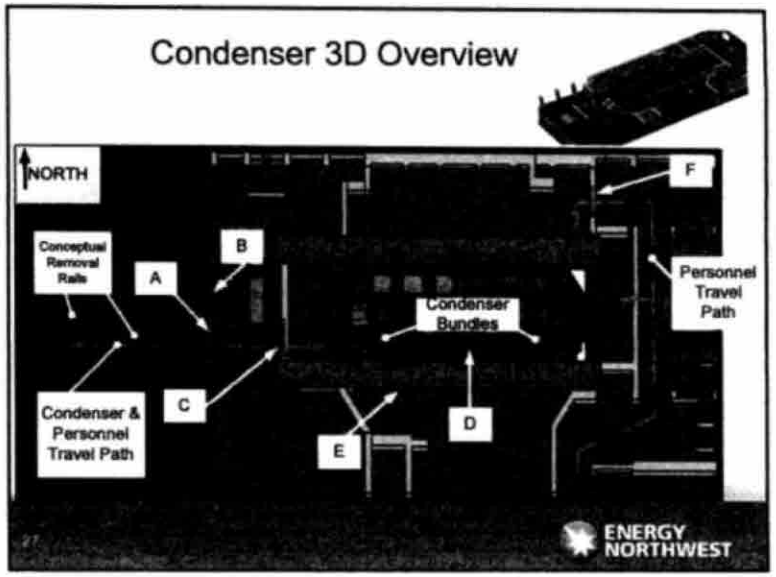
Condenser 3D Overview



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Craig Erier

Design Changes

- R19 Plant Design Changes
  - PDC 6692: Performance Monitoring Instrumentation
  - PDC 6693: Removal of travel path interferences within the TGB
  - PDC 6834: Permanent modifications within the Main Condenser
  - Action Request (AR) Evaluation 6086-07: Evaluation of the travel path exterior to the TGB
- Cycle 20 Engineering Changes
  - Cut access in RV Test shop West wall
  - Relocate Relief Valve Test shop for R20 access
  - Cut access in TG Building west wall
  - Install TB RCA with Temporary building for processing Modules
  - Modify IDS and Security Fencing for module travel
- R20 Engineering Changes
  - Air Removal system modification
  - Module Corrosion Protection (Cathodic Protection)
  - Condenser Module Replacement

Brand new

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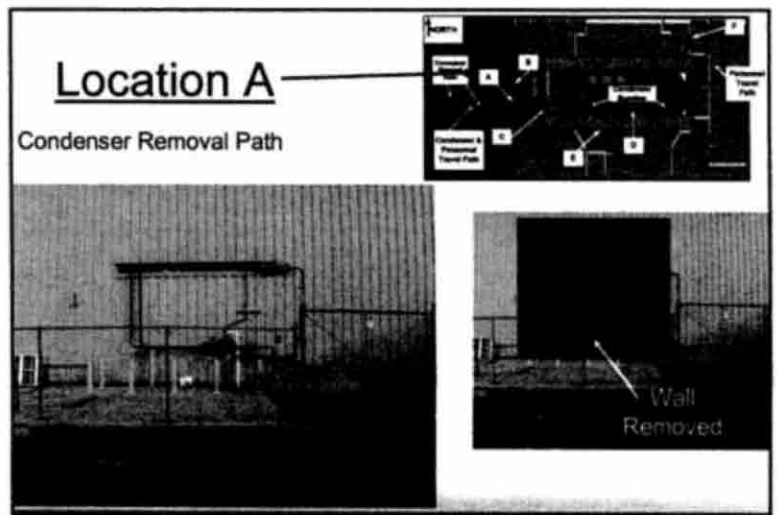
Location A

Condenser Removal Path



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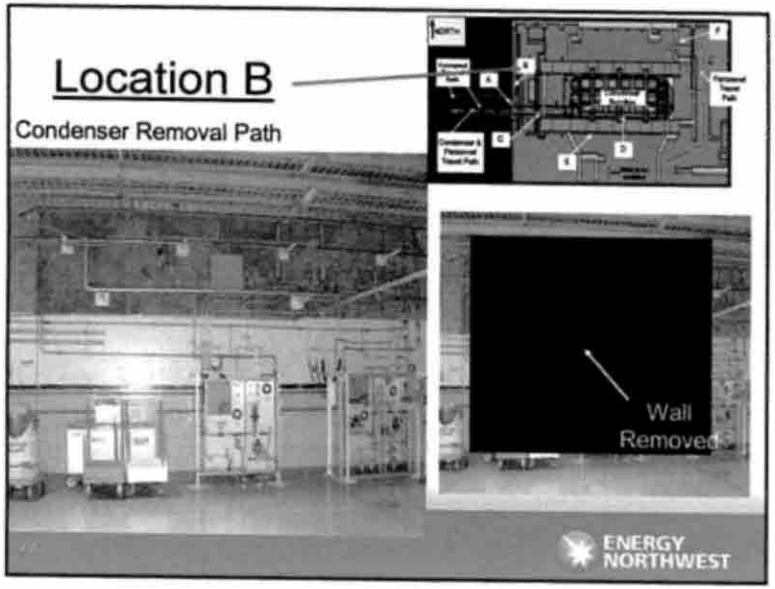
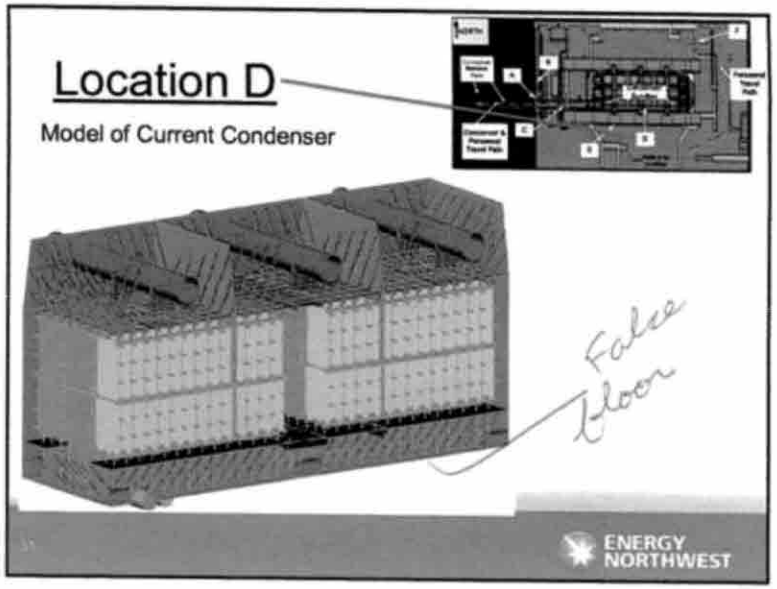
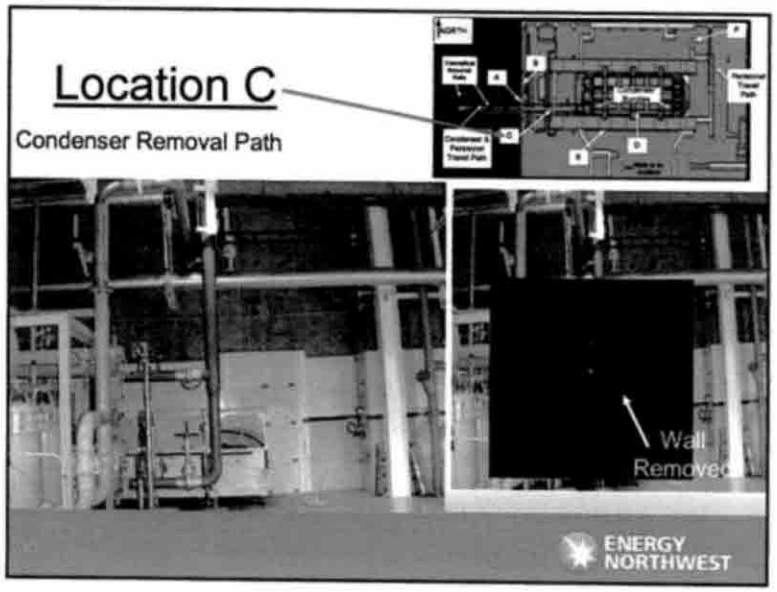
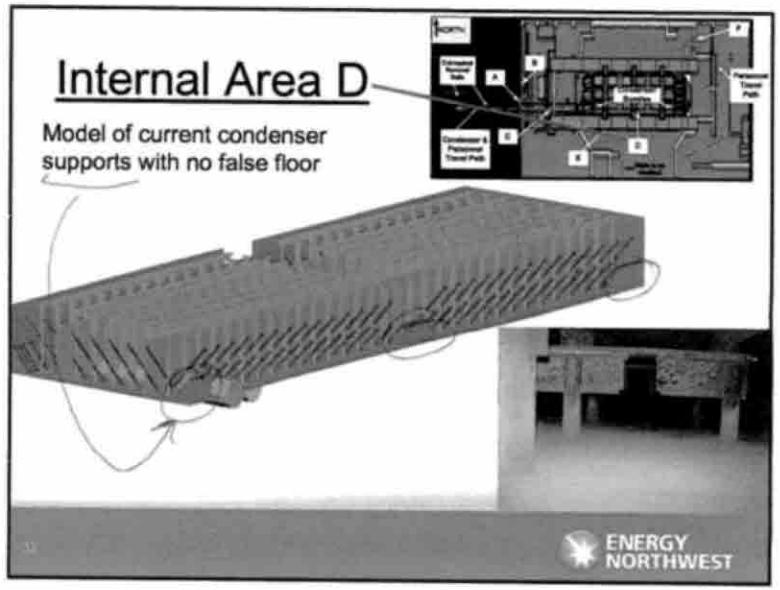




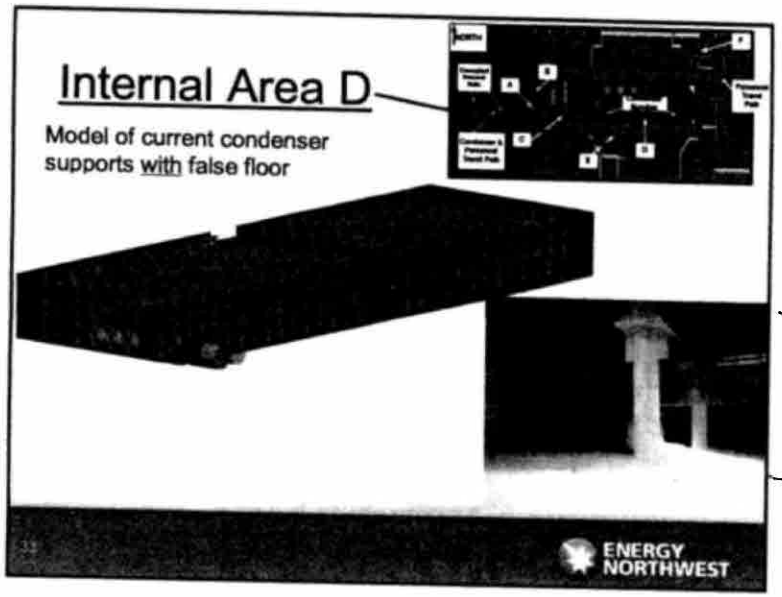
modules



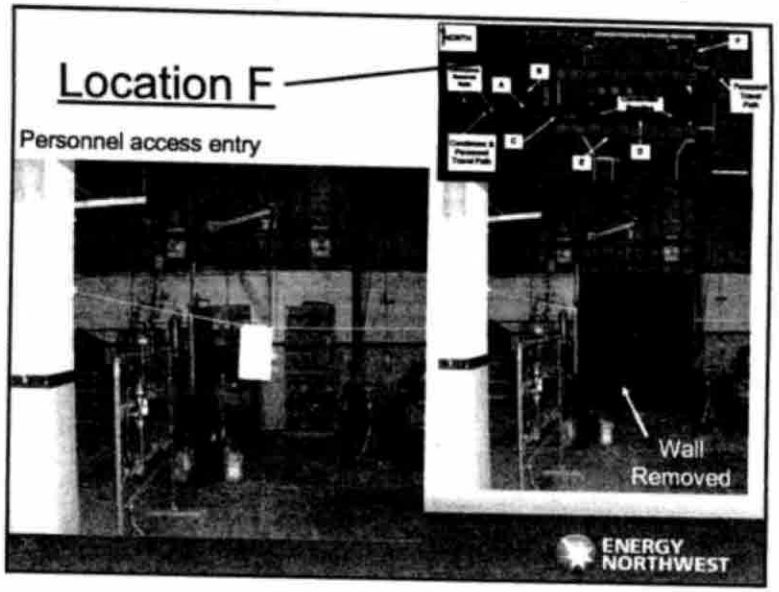


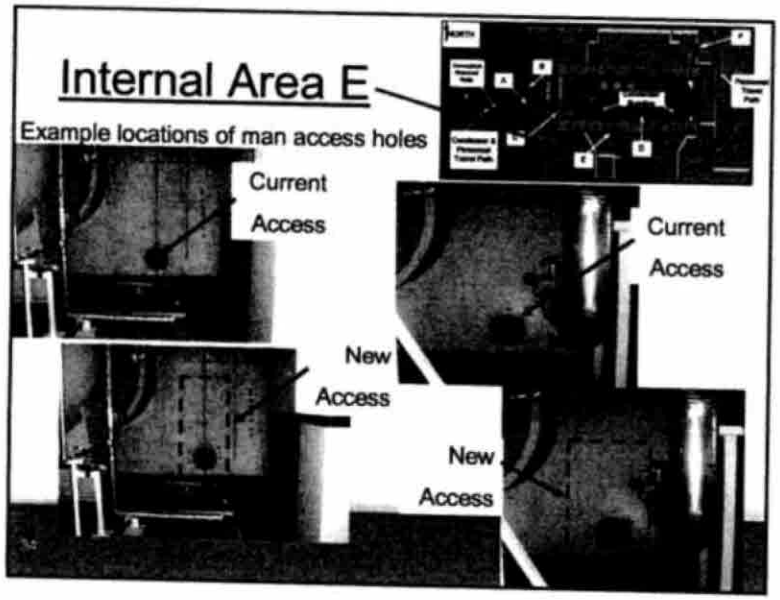
≈ 48 columns to put in.

Relief Valve test shop



2 1/2





Performance Monitoring

- **PDC 6692:** Performance Monitoring instrumentation for the main condenser (ASME PTC 12.2 requirements).
  - R19 Electrical Scope as follows:
    - Condenser Pressure Monitors (18 wireless)
    - Accuracy Improvements (replace 6 existing RTDs)
    - CT Riser Temperatures (12 new RTDs)
    - Sub-cooling RTDs (replace 2 existing RTDs)
    - Install wireless base radios (4 required)
    - Install 1 RTD and 1 Ultrasonic Flow meter to 30"TSW(2)-1
  - R20 Electrical Scope as follows:
    - Condenser Fouling Monitors (60 transmitters)
    - Wireless base radio
    - Data retrieval software

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will be able to monitor these individual tubes.

4 additional projects

~$3M

— John Lovejoy

208 of tubes in R-19

— PM that's Due

Optional Condenser HIT / Scope R-19

Project #	Project Description	Project Summary	Work Orders	Link to Work Instructions / Procedures
102201	Condenser Eddy Current Testing	Provide support to NDE Personnel to Clean, Test and Plug Condenser Tubes. Approved scope includes @ 9600 tubes.	01151702	
1168001	Replace Flexible Seal (Cond-Hx-9 - Dog Bone)	Replace flexible seal between turbine and Condenser located in Condenser at 471 level. Replace seal on COND-HX-1A,1B,1C	01107391	
1811901	Bleed Steam LP Expansion Joint / Condensate Bellows - Removal & Installation	Machine/Grind to remove expansion joints (bellows) for each condenser bay. Install new EJ. Weld per WR 2-10058.	01136212	
1413001	Slop Drain Piping	Replace piping on all 6 slop drains with Schedule 160 pipe inside the main condenser	01136581	
	Outage Incremental WO's	See Listed Below		
Outagr19	Hanger Installation for Hood Spray		01136575	
	Repair Loose U-Bolt		01136577	
	Weld buildup on Piping Inside the main Condenser		01140596	
	Cond-HX-9 Missing Unistrut Clamps on BS Extraction Lines		01136021	

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R19 Outage Work

- Work area setup and controls
- Engineering controls/equipment needs
- Hotwell cleanup
- Hotwell structural modifications
- Temporary shielding for concrete wall removal

Need to get it as clean as possible. This will be key to keeping dose low.

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~~Dave Garza~~ Steve Brush

Project RP Focus Areas

- Interface with EN RP Dept and Vendor
- Contamination controls
  - Reduce the number of PCE's
  - Minimize airborne hazards
- Personnel ingress/egress
- Contaminated equipment handling
- Rad material storage and disposal
- Adequate HP staffing and equipment availability

— low dose but lots of man-hours

↳ IPM-8s HEPA units

inside is all contaminated

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get a 2% right now for work packages

R20 Outage Work

- Ventilation Plan
- Temporary RCA Extension
- Hotwell structural modifications
- Large work force/contamination work

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Kathy Wheelan

Procurement Overview

- Condenser Modules
  - Conducted under Negotiated Competition Statute (exception to Sealed Bidding)
  - Fixed Price contract with milestone payments
  - Price adjustment based on condenser performance
  - Liquidated damages for late delivery
- Design and Installation
  - Conducted under Negotiated Competition Statute (exception to Sealed Bidding)
  - Time-and-Material with Target Pricing
  - Potential for sharing of cost savings associated with cost and schedule efficiencies

measured post installation. heat rate? No leaks? what performance?

cost and schedule

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Facilities – Brian

- Fabrication Shop – Need a new one. – existing one too small.
- East Side Access – working on facility master plan
- New Module Storage
- Old Module Interim Storage – $4.3m worth of brass. Vendor interested in this
- TG Bldg RCA Extension

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Contract Procurement Schedules

Activity	Estimated Dates: Module	Estimated Dates: Installer
Issue Request of Proposal	Complete	Complete
Pre-bid Conference	Complete	Complete
Proposals Due	07-10-08	07-30-08
Visit Vendors (TBD)	08-08	
Offeror's Presentations		08-05-08
Best & Final Offer	09-11-08	09-30-08
Issue Limited Notice to Proceed	10-06-08	10-10-08
Contract Execution	11-06-08	10-30-08

Module Scope -12 Modules
Installer Scope - R-19 Implementation, R-20 Pre-outage Design & Install, R-20 Implementation

each will bring in a team

date oct, early Nov.

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Columbia Generating Station Site Map

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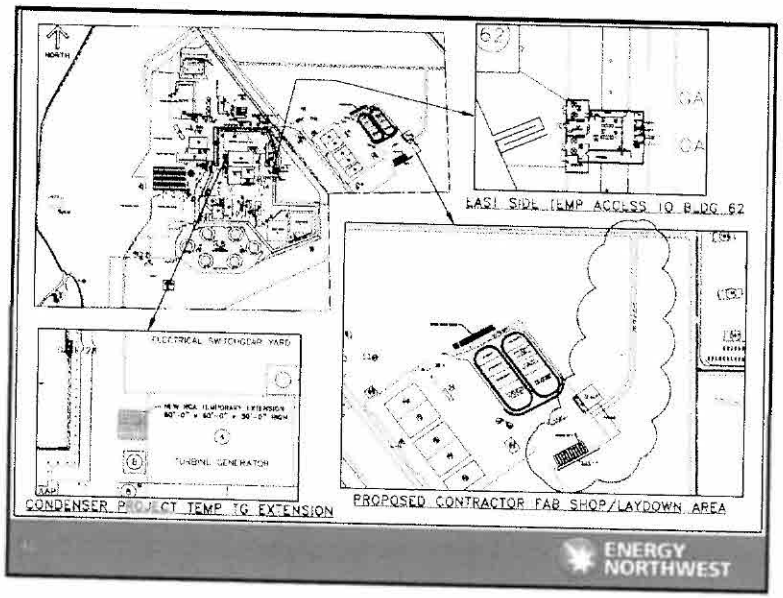

Questions /Answers

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Risks

- Temporary Power — will be a lot more than in the past.
- Facilities
  - East side access
  - Fabrication shop
- Existing Module Disposal — would like to get offsite ASAP.
- Handling/storage/disposal for large volumes of rad materials and equipment
- Contract Award Schedule — just increased time by one month
- Labor Force — will look at doing a labor
  - new NRC 72 hr work rule
  - fatigue rule now
- Project Staffing — staff continuity important
- Air Removal Modification
- Cathodic Protection — don't know what it takes yet.
- Condenser Shell Integrity
- R-20 Design Issues yet to be identified

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condenser bottom?
— integrity?

FINDINGS OF FACT
CONTRACT RELEASE 28
CONTRACT 319873
ENGINEERING DESIGN SUPPORT SERVICES
MAIN CONDENSER REPLACEMENT PROJECT

BACKGROUND/SCOPE

Engineering services are required to provide design change packages for R19 in support of the Main Condenser Replacement Project, currently scheduled for completion in R20. Specifically, services are required to complete the following work:

- Plant Design Change (PDC) 6693 – Identify and design for interferences associated with the transport of the main condenser tube bundles and west/east-end water boxes.
- PDC 6834 – Provide for permanent main condenser modifications to support condenser tube bundle replacement.
- AR Evaluation 6086_Assignment 07 – Provide an evaluation of the travel path of the main condenser tube bundles and west-end water boxes exterior to the Turbine Generator Building.

Sargent & Lundy was selected to perform this work based on the Technical Representative's determination that Sargent & Lundy's on site experience and intimate knowledge of the changes required (gained through their work on the Main Condenser Conceptual Study) makes them the Contractor best able to meet the established milestones to design, plan and schedule work for successful completion.

REQUEST FOR PROPOSAL

Sargent & Lundy has provided the following time-and-materials proposals for the above work:

Task	Price
PDC 6693	$1,160,000
PDC 6834	331,000
AR Evaluation 6086_Assignment 07	145,500
TOTAL	$1,636,500

EVALUATION

The Sargent & Lundy proposals have been evaluated and found to be technically acceptable. This work will be awarded to Sargent & Lundy via Contract Release 28 under current Contract 319873, a master agreement for engineering services that was awarded on a competitive basis. The work under this Release will be performed on a Time-and-Materials basis in accordance with rates established under Contract 319873.

All terms and conditions are in accordance with the blanket master agreement.

FUNDING STATEMENT

Contract Requisition 650971 in the amount of $1,636,500 was approved by S. K. Gambhir, VP Technical Services, on March 10, 2008.

RECOMMENDATION

Based on the foregoing discussion, award of Contract Release 28 under Contract 319873 to Sargent & Lundy in the not-to-exceed amount of $1,636,500 for design engineering services in support of the Main Condenser Replacement Project is recommended, contingent upon receipt of Executive Board approval, BPA nondisapproval and the rights of the Participants Review Board.

APPROVALS

Prepared by: K.A. Whelan 3/11/08
K. A. Whelan, Pr. Contracting Officer

Approved:

M L Wilson
M. L. Wilson, Purchasing/Contracts Supervisor

Angel Rains 11 March 2008
A. D. Rains, Staff Attorney

M L Wilson acting for 3/11/08
L. A. Pagel, Manager, Supply Chain Services

03-11-08

Brian G. Berglin, Condenser Replacement Project Manager

(acting for) 3-12-08

A. E. Mouncer, VP, Corp. Services/General Counsel/CFO

Add a status quo case

Cost comparison of condenser up grade alternatives

	Retube with CuNi 70-30	Retube with Sea-Cure 22BWG	Retube with Titanium 22BWG	Modular bundle Sea-Cure 22BWG	Modular bundle Titanium 22BWG
Capitol cost of the change From report	**$20,000,000**	**$18,748,000**	**$23,050,000**	**$55,250,000**	**$71,250,000**
Installation man rem Estimated ALARA budget (based on .2 to .4 mR/hr)	**8 to 16 man Rem**	**8 to 16 man Rem**	**8 to 16 man Rem**	**40 to 80 man Rem**	**40 to 80 man Rem** John hopes it'd be closer to 40
Outage duration	**60 days Same as retube with SS or titanium coating tube sheet is required**	**68 days Retubeco estimate 6 day weeks-(2) 12-hr shifts** 56 days HEI 7day weeks –(2) 12-hr shifts	**68 days Retubeco estimate 6 day weeks-(2) 12-hr shifts** 56 days HEI 7day weeks –(2) 12-hr shifts	**120 days Retubeco estimate 6 day weeks-(2) 12-hr shifts** 112 days HES estimate 7 day weeks-(2) 12-hr shifts	**120 days Retubeco estimate 6 day weeks-(2) 12-hr shifts** 112 days HES estimate 7 day weeks-(2) 12-hr shifts
FY of the implementation	**2009 R-19**	**2009 R-19**	**2009 R-19**	**2009 R-19** – iffy	**2009 R-19** – iffy
Eddy Current Testing Differential costs	**48,636 tubes Base**	**48,636 tubes $10,000/outage R-19 $75,000 initial install**	**48,636 tubes base**	**116,594 tubes $220,000/outage R-19 $370,000/at initial install**	**116,594 tubes $200,000/outage R-19 $300,000 at initial install**
Scrap recovery (price on 12/14, 2006 $3.04/pound) (1.7 million pounds)	**Not estimated**	**Not estimated**	**Not estimated**	**Not estimated**	**Not estimated**
Duration of forced	**base**	**Base**	**Base**	**Base**	**Base**

due to FME – all the same

Gauge
22 .028
24 .022

	Retube with CuNi 70-30	Retube with Sea-Cure 22BWG	Retube with Titanium 22BWG	Modular bundle Sea-Cure 22BWG	Modular bundle Titanium 22BWG
outage due to FME					
Based on NO tubes plugged Summer derate total MWe Hrs based on 130F max. hotwell temp. and 0 plugged tubes	**0**	**32.0 (June 21.3, July 10.5)**	**5.5 (June only)**	**0**	**0**
problem with sprate in summer Available annual output compared to design at 0 tubes plugged gain (loss)	**base**	**(27,818 MWe)** per year just based on design	**(17,133 MWe)**	**82,362 MWe**	**87,048 MWe** ← driving now
Maintaining the cleanliness factor >90% Potential gain compared to CF @ 60% (indicates sensitivity to fouling)	**Not evaluated**	**Not evaluated**	**23.9 MWe**	**Not evaluated**	**8.6 MWe** lot more tubes so not as sensitive to cleanliness.
Cost reduction if outage duration is reduced 30 days (rebundle) Sensitivity analysis only	**Not evaluated**	**Not evaluated**	**Not evaluated**	**90 days** Assume they could get to 90 days	**90 days** Assume.
Sales tax 8.3%					
Deep bed demineralizer	**$20-30 million**	**Not required**	**Not required**	**Not required**	**Not required**

Experience with leak repairs

levi will get better info on this

Assumptions
Use Sargent and Lundy cost estimates that are in 2006 dollars
Use Sargent and Lundy outage time estimates
Scrap recovery costs are not included at this time

Existing brass tubed condenser condition assessment

1. Six reduced power or shutdown conditions have occurred since 2004. The direct costs to Columbia averages $350,000 per outage. The lost MW-hrs and costs are displayed below. The total dose for these six events totals 12 ManR.

all from Dave Krieg

	lost power MW-hrs	Power Worth @ $32.45/MWhr
1/24/2004 Main Condenser Tube Leak	35310	$1,145,809.50
5/25/04 to Main Condenser Tube Leak Repair	17777	$ 576,863.65
11/5/2005 Down power to locate and repair condenser	23561.2	$ 764,560.83
1/5/2006 t Down power to locate and repair condenser	28994	$ 940,855.30
2/15/2006 Down power to locate and repair condenser	41244	$1,338,367.80
3/28/2006 Down power to locate and repair condenser	29995	$ 973,337.75
TOTAL	176881.2	$5,739,794.83

Condenser in leakage is due to chronic small leaks will continue as the condenser ages and will eventually require condenser retubing.

2. Condenser in leakage is the major factor which challenges reactor water chemistry at Columbia.
The existing condenser with the brass tubing adds soluble and insoluble copper to the reactor water. The Noble metals and hydrogen addition to the reactor causes the copper in the reactor water to plate out on the reactor surfaces. The presence of significant amounts of copper constitutes a substantial increase in the risk of fuel failure should a fuel corrosion event occur. Fuel corrosion has been responsible for fuel failures at other Plants in the late 1970's and 1980's. Recent fuel failures have been attributed to cladding corrosion from heavy crud corrosion. At most stations, the corrosion failure mechanism was mitigated by improvement of the nodular corrosion resistance of the fuel cladding, and in many of the cases by removal of the copper source (by replacement of brass condenser tubing or with improved condensate treatment technologies.
Following Cycle 15 Columbia experienced a case of enhanced cladding nodular corrosion, but with out cladding failure. The

? Shawn

industry and INPO have urged the plants to meet the water chemistry goals from BWRVIP-130. Vermont Yankee and Columbia are the last two US nuclear plants with out a deep bed demineralizer that have copper condenser tubing. The Probability that copper in the feed water, at present concentrations will result in fuel failure is unknown. This risk has a severe outcome if it does result in fuel failure. Experience from other plants that have fuel failures would result in the following costs to Columbia; the failed fuel would be examined to perform crud analysis/corrosion thickness analysis and root cause for about $4,000,000, and then an emergency procurement of 100 fuel bundles @$250,000 each. The plant would be in outage for approximately 2 months and the reactor would be defueled to remove the damaged fuel and then refueled with the new fuel. The direct costs for the outage would be $?????. The estimated dose for defueling-refueling is 17 Man R. Long term affects would last for several years in the form of higher dose and contamination.

3. The presence of copper in the reactor water negates the benefits of zinc injection for dose reduction. The shutdown dose rates for Columbia are the highest in the BWR fleet and are showing an increasing trend. The dose estimate increase is approximately 50 man R each outage.

4. Columbia's brass tubed condenser has a useful life of about 30 years. Retubing with brass will provide a condenser that can run Columbia until 2043. The existing Brass condenser could be retubed with outage duration the same as Sea-Cure or Titanium since coating the tube sheet is required to assure a leak tight joint. The tube plugging of 2017 tubes in the condenser was due to; poor chemistry control, FME, factory tubing inspection by the fabricator that accepted tubes that were not suitable for quality performance demanded for today's nuclear plants, and tubes at the top of the condenser need to be shielded from mechanical damage, steam and water impingement.

5. A deep bed demineralizer is required if brass/copper tubes are selected to remain in the condenser. The Sargent and Lundy report did not estimate the cost to engineer and install a deep bed demineralizer system. An order of magnitude would be $20,000,000 to 30,000,000. If the addition is to the south of the Radwaste Building, another blast resistant enclosure is required for $500,000 and 5 additional security personnel needs to be hired to man the BRE.

Department of Energy

Bonneville Power Administration
Mail Drop 1399
P.O. Box 968
Richland, Washington 99352-0968

POWER SERVICES

April 7, 2008

In reply refer to: PGC/Richland

Mr. S. K. Gambhir, Vice President
Technical Services
Energy Northwest M/D PE04
P. O. Box 968
Richland, WA 99352-0968

Dear Mr. Gambhir:

In reference to your letter "Energy Northwest Agreement 319873 Contract Release 28 Main Condenser Project Design Support," dated March 24, 2008, and received on April 1, 2008, the Bonneville Power Administration does not disapprove the execution of the proposed purchase action.

The proposed action would authorize Energy Northwest to execute Contract Release 28 to Agreement 319873 with Sargent & Lundy LLC, in an amount not to exceed $1,636,500 for design and engineering services in support of the Main Condenser Replacement Project.

Sincerely,

Andrew J. Rapacz, Manager
Contract Generating Resources

cc:
Ms. Lynne A. Pagel, Energy Northwest - PE10
Mr. Michael L. Wilson, Energy Northwest - PE10

bcc:
Official File – PGC (PM-14-23) (Columbia)
ERMS: http://bpaweb/services/erms/PM/14/23/PGC%20Records/Forms/AllItems.aspx

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Reviewed: DR for PES 4/7/08
PES / date

BONNEVILLE POWER ADMINISTRATION
CONTRACT GENERATING RESOURCES (PGC)
Briefing Paper, Columbia Generating Station (CGS)
Energy Northwest Agreement 319873 Contract Release 28
Main Condenser Project Design Support

REFERENCE: Energy Northwest letter to A. J. Rapacz, "Energy Northwest Agreement 319873 Contract Release 28 Main Condenser Project Design Support," dated March 24, 2008, and received on April 1, 2008.

CONTRACT: Energy Northwest Agreement 319873 Contract Release 28 Main Condenser Project Design Support.

ACTION TOPIC: Energy Northwest has requested BPA's non-disapproval for execution of Energy Northwest Agreement 319873 Contract Release 28 Main Condenser Project Design Support with Sargent & Lundy LLC, in an amount not to exceed $1,636,500, for design and engineering services in support of the Main Condenser Replacement Project.

DISCUSSION: The purpose of this contract is to purchase design engineering services for activities related to replacement of the main condenser. This contract is part of a larger overall effort executed as a phased approached to replace the main condenser tubing and supports with pre-fabricated titanium modular bundles. Sargent & Lundy will design and plan work to be done in R-19, to remove interferences to module replacement, modify the condenser floor to support module weight during replacement and to do detailed analysis of the expected module removal path.

The following discussion is referenced from Energy Northwest studies and presentations. The current progress of the main condenser replacement project is summarized as follows:

- Main condenser upgrade scoping study performed in September 2006
- Recommended titanium re-tube of the condenser to the Board of Directors on March 21, 2007
- Joint pull-out test conducted by Retubeco was unsatisfactory – May 2007
- All re-tubing options using existing tube sheets were eliminated due to failure of the pull-out test
- Conceptual study evaluating the removal and installation of tube bundles (Draft complete December 3, 2007)
- Project plan in progress

The overall condenser replacement project is planned as a phased approach as follows during FY 2008 to FY 2012:

FY 2008 (non-outage year)

- Complete conceptual study "Project Plan"
- Complete independent business case by Huron
- Commence R-19 design changes (Electrical, Mechanical, Civil)
- Information Memorandum for full project funding
- Action Memorandum for full project funding
- Complete modular tube bundle Material Procurement Specification and award contract

FY 2009 (R-19 outage year)

- Complete R-19 design modifications and work order planning
- Complete turn-key contract process / award contract
- Implement R-19 design modifications
- Begin turn-key contractor mobilization

FY 2010 (non-outage year)

- Complete on-line design modifications
- Complete R-20 design changes

FY 2011 (R-20 outage year)

- Receive main condenser modules on-site
- Implement R-20 design modifications
- Condenser module replacement

FY 2012 (non-outage year)

- Post outage demobilization and disposal

The main condenser is a critical component and is required for operation of CGS. Sustained poor maintenance and inadequate foreign material exclusion control has created a situation of condenser tube failure and resulting unplanned plant down powers for tube leak repairs. Additional concerns related to high levels of copper (Admiralty Brass) contained in the current condenser tube material challenge reliable operation and minimization of radiation dose to employees. Reliable operation of this system is a high priority for CGS. The maintenance and repairs performed during the last refueling outage R-18 have proven effective with no measurable tube leaks to date. Energy Northwest does anticipate however, that new tube leaks will develop at some point in the future. With the extensive tube plugging in R-18, it is hoped that CGS can run until R-19 with no leaks or minimal leaks. As stated by the Energy Northwest VP of Technical Services at the March 2008 Board of Directors meeting, the continued operation of the main condenser is not a nuclear safety issue.

Additional drivers for main condenser replacement include:

1. High copper levels that impact:
   - Reactor Vessel Internals Program
   - Increased potential for fuel failure
   - Elevated drywell dose rates
   - Require chemical decontamination at $5M per outage required until copper condenser is replaced
2. Industry perspective:
   - INPO specifically noted material condition as contributing factors for failing to meet BWR Vessel Inspection Program guidance
   - CNSRB has noted concerns that are similar to INPO concerns
3. Performance issues
   - Unplanned down powers due to tube leaks
   - Seven power reductions or shutdowns since 2003
   - Condenser end-of-life is currently projected to be 2018

Several business cases and cost benefit analyses were completed to determine the options, risks, and costs for main condenser replacement:

- Base Case FY 2019 (R-24) – Delay condenser project until predicted end of life 2018 – retube with titanium and new tubesheets
- Option 1: FY 2019 (R-24) – Same as Base Case except – Replace condenser with titanium modular bundles
- Option 2: FY 2011 (R-20) – Replace condenser with modular tube bundles in FY 2011 – SeaCure (Stainless steel tube bundles)
- Option 3: FY 2011 (R-20) – Replace condenser with modular tube bundles in FY 2011 – Titanium tube bundles
- Option 4: FY 2011 (R-20) – Retube with titanium tubes and new tubesheets in FY 2011

The estimated capital costs and lifecycle costs Net Present Value (NPV) of the above options relative to the base case are as follows:

	FY08 $M (+ or - 25%)				
	Base Case FY19 Retube Titanium	Option 1 FY19 Modular Titanium	Option 2 FY11 Modular SeaCure	**Option 3 FY11 Modular Titanium**	Option 4 FY11 Retube Titanium
Total Capital Costs	$ 67.8	$ 89.4	$ 79.4	$ 89.4	$ 67.8
Installation Risk	**High**	**Moderate**	**Moderate**	**Moderate**	**High**
Operation Risk	**High**	**High**	**High**	**Low**	**Moderate**
Generation Impact	**Negative**	**Negative**	**Positive**	**Positive**	**Negative**
NPV versus Base Case	**$0.0**	**$ 39.7**	**$ 77.6**	**$ 103.9**	**$ 31.4**
Recommended Option					

Included in the cost benefit analyses are lost generation during the extended R-20 outage for implementation, increased generation efficiency for modular replacement, radiation dose savings, resin purchase and disposal savings, chemical decontamination cost savings, and annual inspection and eddy current testing and tube cleaning savings. Option 3 was selected as the most cost effect with a positive NPV of $103.9M. The following summarizes the conclusions of the main condenser replacement project:

1. All re-tubing options utilizing existing tube sheets are eliminated
2. Replacing tubes with titanium tubes and sheets utilizing the same baffles:
   - High installation risk
   - High potential to extend outage duration
   - Lower plant thermal performance
3. Titanium modular replacement results in a higher initial cost but offer:
   - The best NPV
   - Lowest installation risk
   - Better thermal performance
   - Retain the option for future power up-rate

FUNDING: Funding for this contract is included in the FY 2008 Budget.

ISSUES: None with this action.

ACTION: BPA agrees replacing the main condenser tubing will improve the system reliability and significantly addresses reliability concerns. PGC staff will prepare a letter of non-disapproval.

bcc: Official File – PGC (PM-14-23) (Columbia)
ERMS: http://bpaweb/services/erms/PM/14/23/PGC%20Records/Forms/AllItems.aspx

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Reviewed: PES 4/7/08 AJR 4/7/08
PES / date AJR / date

ENERGY NORTHWEST

Sudesh K. Gambhir
Vice President, Technical Services
P.O. Box 968, PE04
Richland, WA 99352-0968
Ph. 509 377 8313 | F. 509 377 2354
sgambhir@energy-northwest.com

March 24, 2008

BPA
APR 1 2008
RICHLAND

Mr. Andrew J. Rapacz, M/D 1399
Manager Contract Generating Resources
Bonneville Power Administration
U.S. Department of Energy
c/o Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

Dear Mr. Rapacz:

Subject: **ENERGY NORTHWEST AGREEMENT 319873**
CONTRACT RELEASE 28
MAIN CONDENSER PROJECT DESIGN SUPPORT

Energy Northwest intends to execute Contract Release 28 to Agreement 319873 with Sargent & Lundy LLC in the not-to-exceed amount of $1,636,500 for design engineering services in support of the Main Condenser Replacement Project.

This contract action is subject to the right of the Administrator, Bonneville Power Administration, to disapprove pursuant to the Project Agreement.

Complete details of the aforementioned transaction are on file in Supply Chain Services and can be made available to you upon request.

Respectfully,

S.K. Gambhir
Vice President, Technical Services

/kaw

ENERGY NORTHWEST

P.O. Box 968
Richland, WA 99352-0968

ACTION MEMORANDUM NO. 1050

DESIGN ENGINEERING SUPPORT SERVICES

PURPOSE

The purpose of this Action Memorandum is to obtain Executive Board approval for the award of Contract Release 28 under Contract 319873 to Sargent & Lundy for design engineering support services.

BACKGROUND

Engineering services are required to provide design change packages for R19 in support of the Main Condenser Replacement Project, which is currently scheduled for completion in R20. Services include designing, planning and scheduling work associated with (1) interferences associated with the transport of the main condenser tube bundles and west/east end water boxes; (2) permanent main condenser modifications to support condenser tube bundle replacement; and (3) an evaluation of the travel path of the main condenser tube bundles and west-end water boxes exterior to the Turbine Generator Building.

DISCUSSION

Energy Northwest has made the determination that Sargent & Lundy is the contractor best able to provide the required expertise to design, plan and schedule this work for successful completion in R19. The work will be awarded to Sargent & Lundy via a contract release under a current master agreement for engineering services that was awarded on a competitive basis. All work under the release will be performed in accordance with the rates and terms of the master agreement, Contract 319873.

RECOMMENDATION

It is recommended that the Executive Board authorize the award of Contract Release 28 under Contract 319873 to Sargent & Lundy in the amount of $1,636,500. This action is subject to the contractual rights of Bonneville Power Administration and the Participants' Review Board.

JW Baker for J.V. Parrish — 3/13/05

Office of the Chief Executive Officer — Date

DRAFT

EXECUTIVE BOARD

RESOLUTION NO. 1539

A RESOLUTION AUTHORIZING THE EXECUTION OF RELEASE NO. 28 TO CONTRACT NO. 319873 WITH SARGENT & LUNDY LLC FOR DESIGN ENGINEERING SUPPORT SERVICES RELATING TO THE MAIN CONDENSER REPLACEMENT PROJECT – COLUMBIA GENERATING STATION

The Chief Executive Officer reports that engineering services are required to provide design change packages for the R-19 outage in support of the Main Condenser Replacement Project, which is currently scheduled for completion during the R-20 outage, and

The Chief Executive Officer further reports that in order to complete the design engineering support services necessary to replace the Main Condenser, services of a design engineering support firm are needed, and

The Chief Executive Officer further reports that Energy Northwest previously awarded two design engineering support blanket contracts to Enercon Services, Inc. and Sargent & Lundy LLC through a competitive process authorized under Chapter 39.80 of the Revised Code of Washington, that specific services provided by the two firms are procured through contract releases, and that a proposal was requested from Sargent & Lundy LLC based upon its previous involvement in producing the conceptual study of the Main Condenser Replacement Project, proven on-site experience, and extensive knowledge of the changes required. Upon evaluation of the proposal, the staff determined that Sargent & Lundy LLC was qualified for this type of service and the staff was able to negotiate a fair and reasonable price for the service; and

Having reviewed the foregoing, the Executive Board finds that the execution of Contract Release No. 28 to Contract No. 319873 with Sargent & Lundy LLC, in an amount not to exceed $1,636,500 for design engineering support services relating to the Main Condenser Replacement Project, is advantageous to Energy Northwest and is in the best interests of Energy Northwest and the electric ratepayers of the Pacific Northwest; NOW, THEREFORE,

IT IS RESOLVED that the Chief Executive Officer, or his designee, is hereby authorized to execute Release No. 28 to Contract No. 319873 with Sargent & Lundy LLC in an amount not to exceed $1,636,500 for the procurement of design engineering support services relating to the Main Condenser Replacement Project, subject only to the contractual rights of the Bonneville Power Administration and the Participants' Review Board.

ADOPTED by the Executive Board of Energy Northwest this 27th day of March, 2008.

Chairman

ATTEST:

Secretary

APPROVED AS TO FORM
AND LEGALITY:

Counsel

Project Costs	FY08	FY09	FY10	FY11	FY12
Procurement					
Procurement of Condenser	-	18,630	18,630	4,140	-
Installation					
Internal Labor	600	1,000	800	1,400	200
External Labor	280	8,400	2,520	16,800	-
Design and Project Support					
Security Modifications	250	2,000	1,250	1,500	-
Design Packages	2,625	2,250	750	1,875	-
Facilities	-	1,346	1,009	1,009	-
In-processing	-	1,009	-	2,355	-
Project Close-out					
Decon / Disposal	-	-	-	-	7,980
Demob and Closeout	-	-	-	829	276
Taxes					
Washington State	236	2,000	1,835	632	-
Project Cost Cash Flow	**$ 3,991**	**$ 36,635**	**$ 26,794**	**$ 30,540**	**$ 8,456**
Generation				71,756	
Radiation				521	
Project Cost	$ 3,991	$ 36,635	$ 26,794	$ 102,817	$ 8,456
TOTAL	$ 178,693				

ENERGY NORTHWEST

Condenser Replacement Project Update

Project No. 00608601

Executive Board
December 12, 2007
Sudesh Gambhir

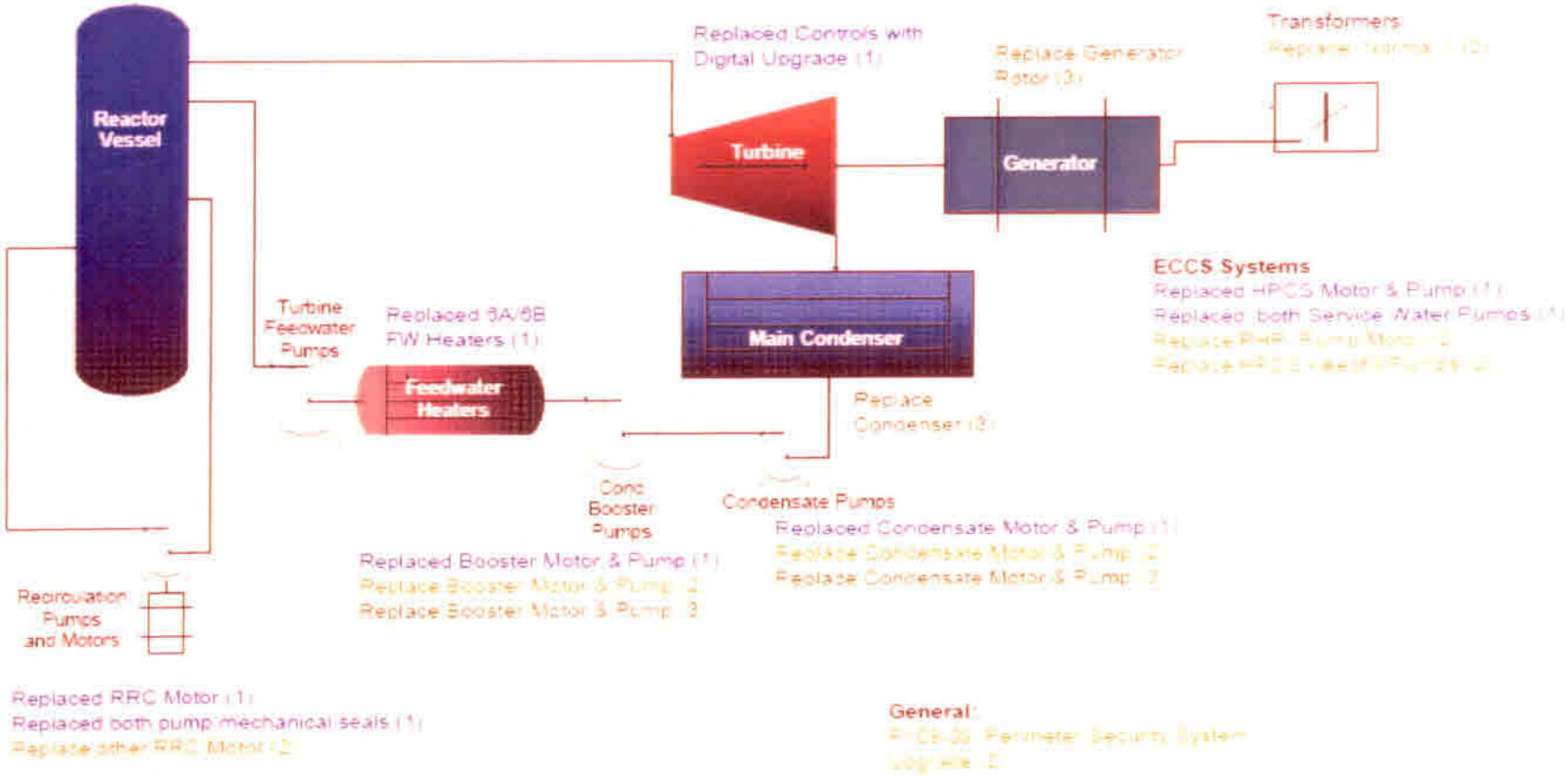
Presentation Outline: Condenser Replacement

Vision	Gambhir
Project Background	Gambhir
Drivers for Condenser Replacement	Gambhir
Condenser Replacement Progress	Gambhir
Business Case	Ridge
Conceptual Plan for Condenser Replacement	Berglin
Industry Experience and Path Forward	Gambhir

CGS VISION

- To achieve operational excellence at Columbia Generating Station as reflected by performance in the top-quartile of nuclear plants nationwide based on the WANO Performance Indicators and the INPO Performance Indicator Index.

Columbia Generating Station
Plant Reliability Improvements



Note:
Some of the planned projects are subject to change based on plant priorities, as-found equipment condition and emergent plant issues.

Legend
In BLUE, project is complete (1)
In Orange, project planned to be done by end of next outage (2)
In GREEN, project planned to be completed past next outage (3)

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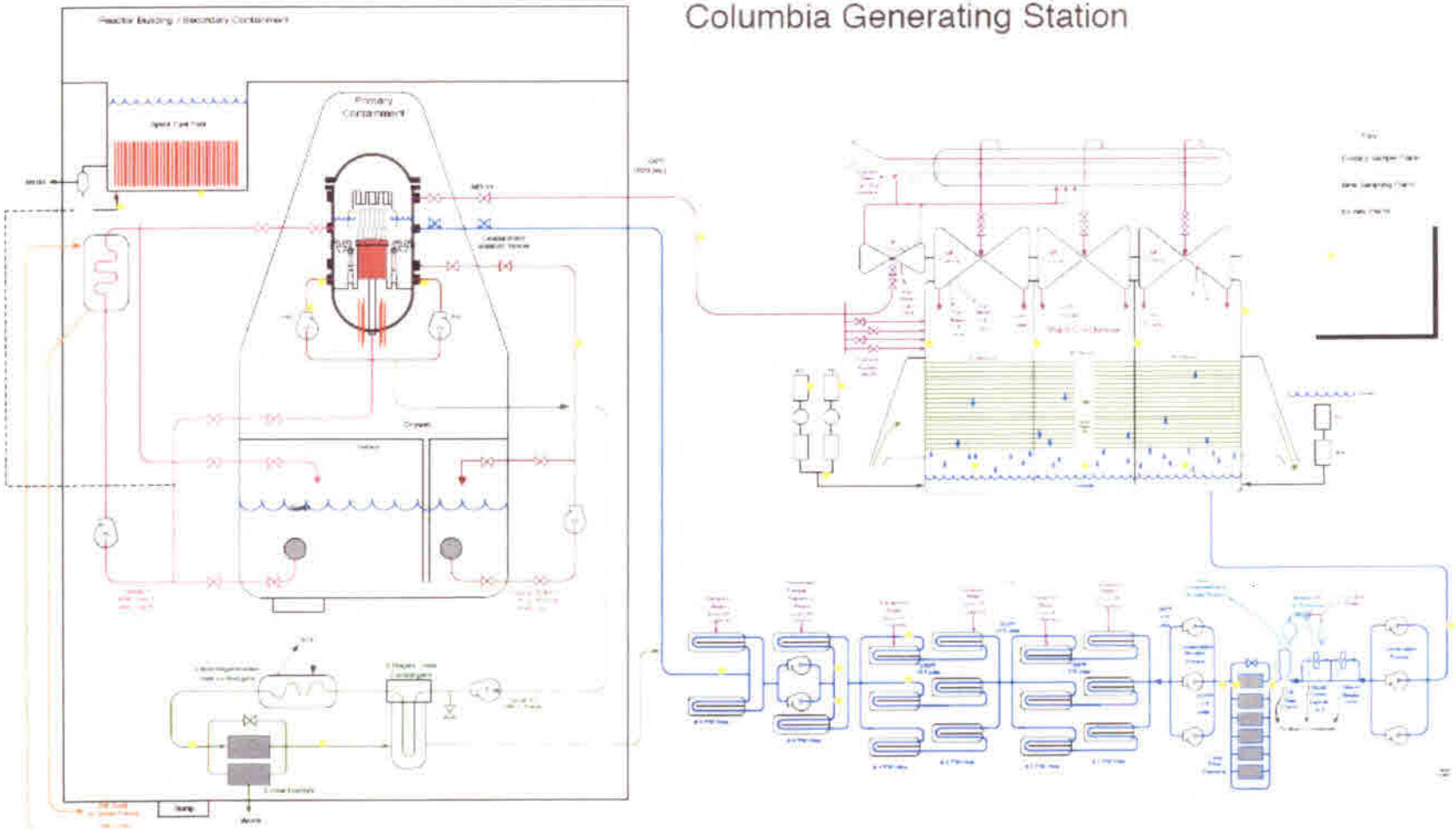
Main Condenser: Plant Steam Cycle

Columbia Generating Station



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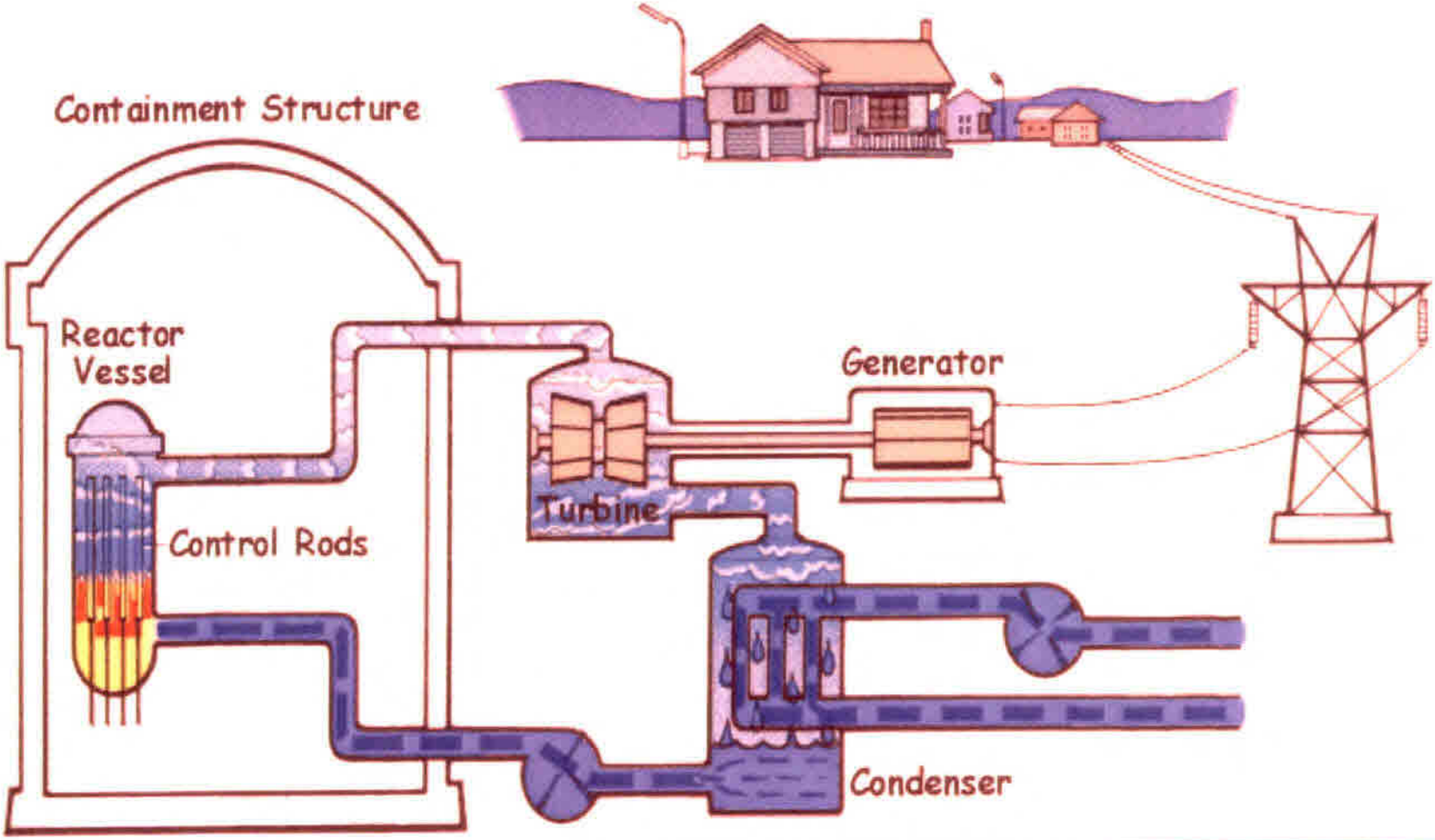
BWR Steam Cycle



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Drivers for Condenser Replacement

- High Copper Level Impacts
  - Rx Vessel Internals Program
  - Increased potential for fuel failure
  - Elevated drywell dose rates
  - Decon at $5M per outage required until copper replaced
- Industry Perspective
  - INPO specifically noted material condition as contributing factors for failing to meet BWR Vessel Inspection Program (BWRVIP) guidance.
  - CNSRB has noted concerns that are similar to INPO concerns
- Performance Issues
  - Down powers due to tube leaks
  - Seven power reductions or S/D's since 2003
  - End of life is currently projected to be 2018

Condenser Replacement Progress

- Main Condenser Upgrade Scoping Study Performed in September 2006
- Recommended titanium re-tube of the condenser to the Board on 03-21-07
- Joint pull out test conducted by Retubeco was unsatisfactory-May 2007
- All re-tubing options using existing tube sheets were eliminated due to failure of the pull out test
- Conceptual Study evaluating the removal and installation of tube bundles (Draft comp. 12-3-07)
- Project Plan in progress

Business Case Revisions

- Request by BPA to evaluate condenser option for component end of life replacement incorporated into the Business Case
- Business Case Revision draft completed

Options Considered

- **Base Case FY19 (R-24)** – Delay condenser project until predicted end of life 2018 – retube with titanium and new tubesheets
- **Option 1 FY19 (R-24)** – Same as Base Case except – Replace condenser with titanium modular bundles
- **Option 2 FY11 (R-20)** – Replace condenser with modular tube bundles in FY11 – SeaCure (Stainless steel tube bundles)
- **Option 3 FY11 (R-20)** – Replace condenser with modular tube bundles in FY11 – Titanium tube bundles
- **Option 4 FY11 (R-20)** – Retube with titanium tubes and new tubesheets in FY11

Recommended Option

- **Option 3 FY11 (R-20)** – Replace condenser with modular tube bundles in FY11 – Titanium tube bundles

Estimated Capital Costs and Lifecycle Costs Net Present Value (NPV) of Options versus Base Case

	FY08 $M (+ or - 25%)				
	Base Case FY19 Retube Titanium	Option 1 FY19 Modular Titanium	Option 2 FY11 Modular SeaCure	**Option 3 FY11 Modular Titanium**	Option 4 FY11 Retube Titanium
Total Capital Costs	$ 67.8	$ 89.4	$ 79.4	$ 89.4	$ 67.8
Installation Risk	High	Moderate	Moderate	Moderate	High
Operation Risk	High	High	High	Low	Moderate
Generation Impact	Negative	Negative	Positive	Positive	Negative
NPV versus Base Case	$0.0	$ 39.7	$ 77.6	$ 103.9	$ 31.4

Recommended Option

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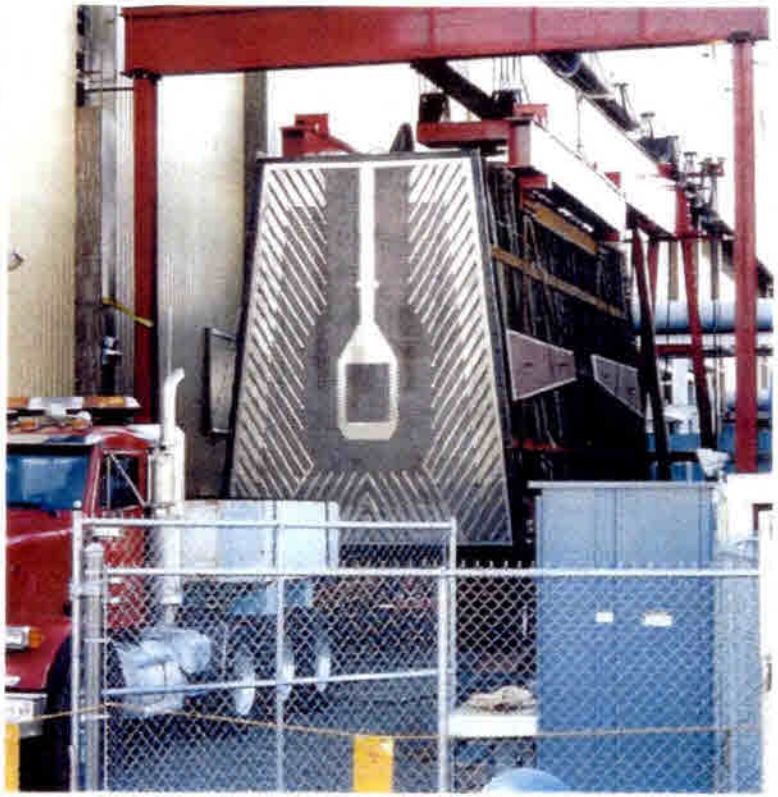
Condenser Replacement Conclusions

- All re-tubing options utilizing existing tube sheets eliminated
- Replacing tubes with titanium tubes & sheets utilizing the same baffles
  - High installation risk
  - High potential to extend Outage duration
  - Lower plant thermal performance
- Titanium modular replacement results in a higher initial cost but offer:
  - The best NPV
  - Lowest installation risk
  - Better thermal performance
  - Retain the option for power up-rate

Main Condenser Modules



Main Condenser Module

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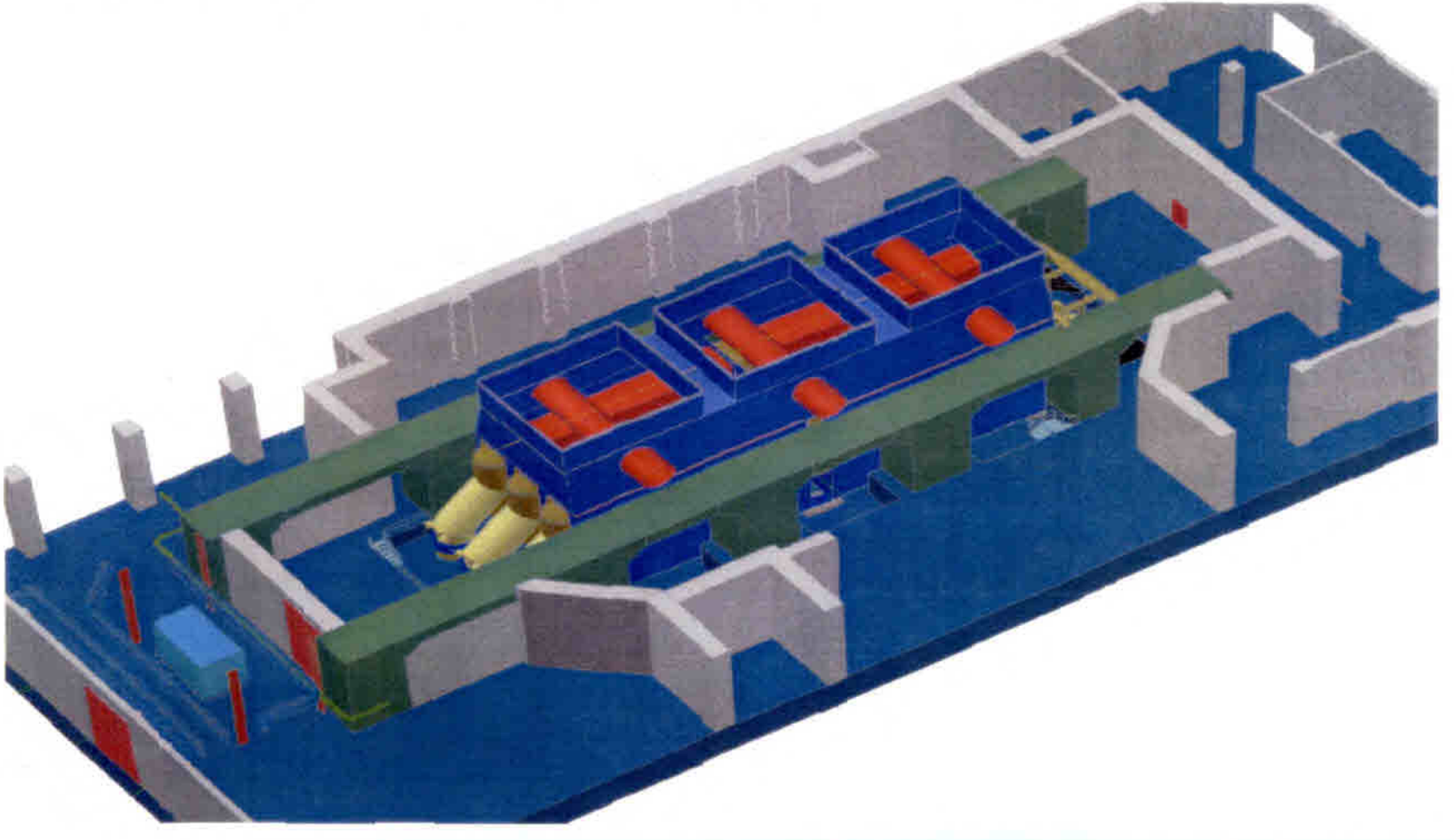
Main Condenser Project: 3D overview



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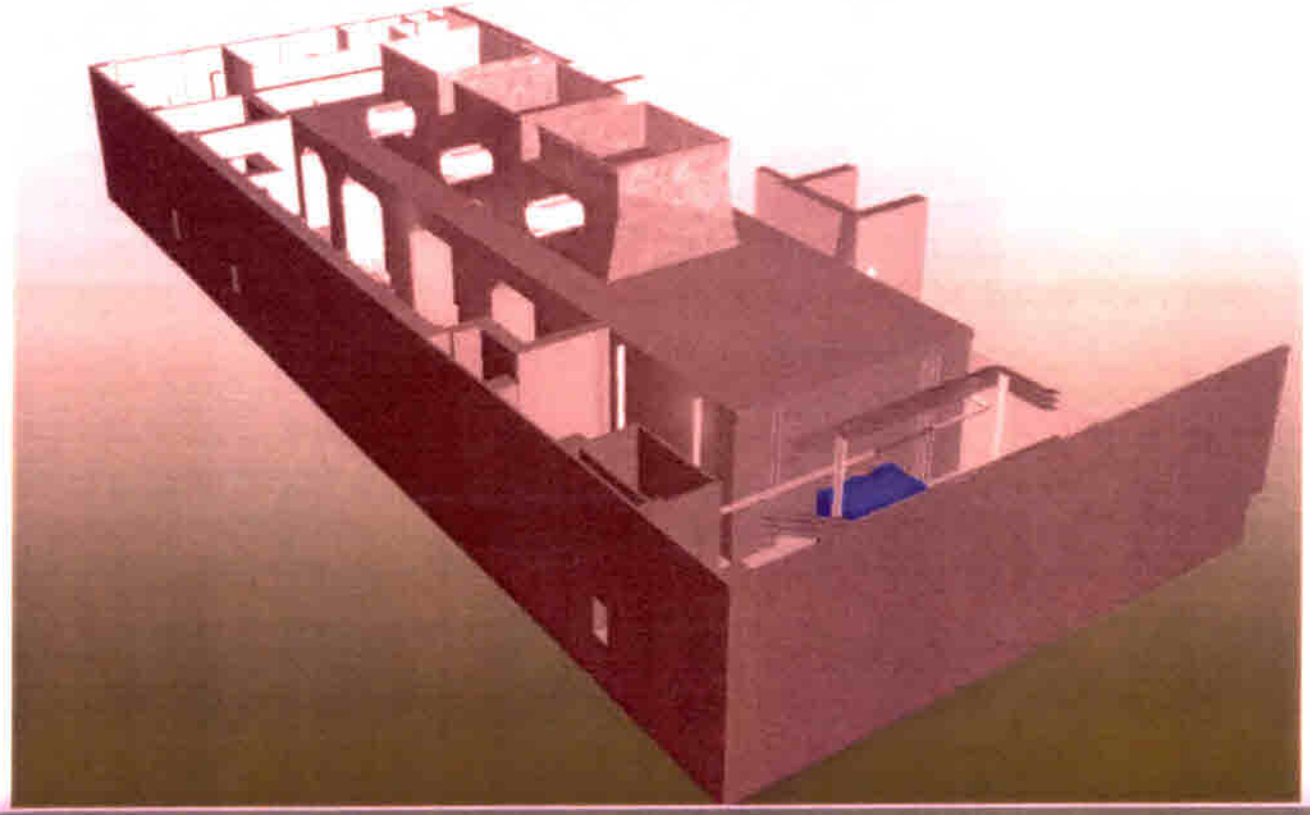
Main Condenser Project: Animation



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Condenser Replacement Update

PWR (non-contaminated) Tube Removal (video)

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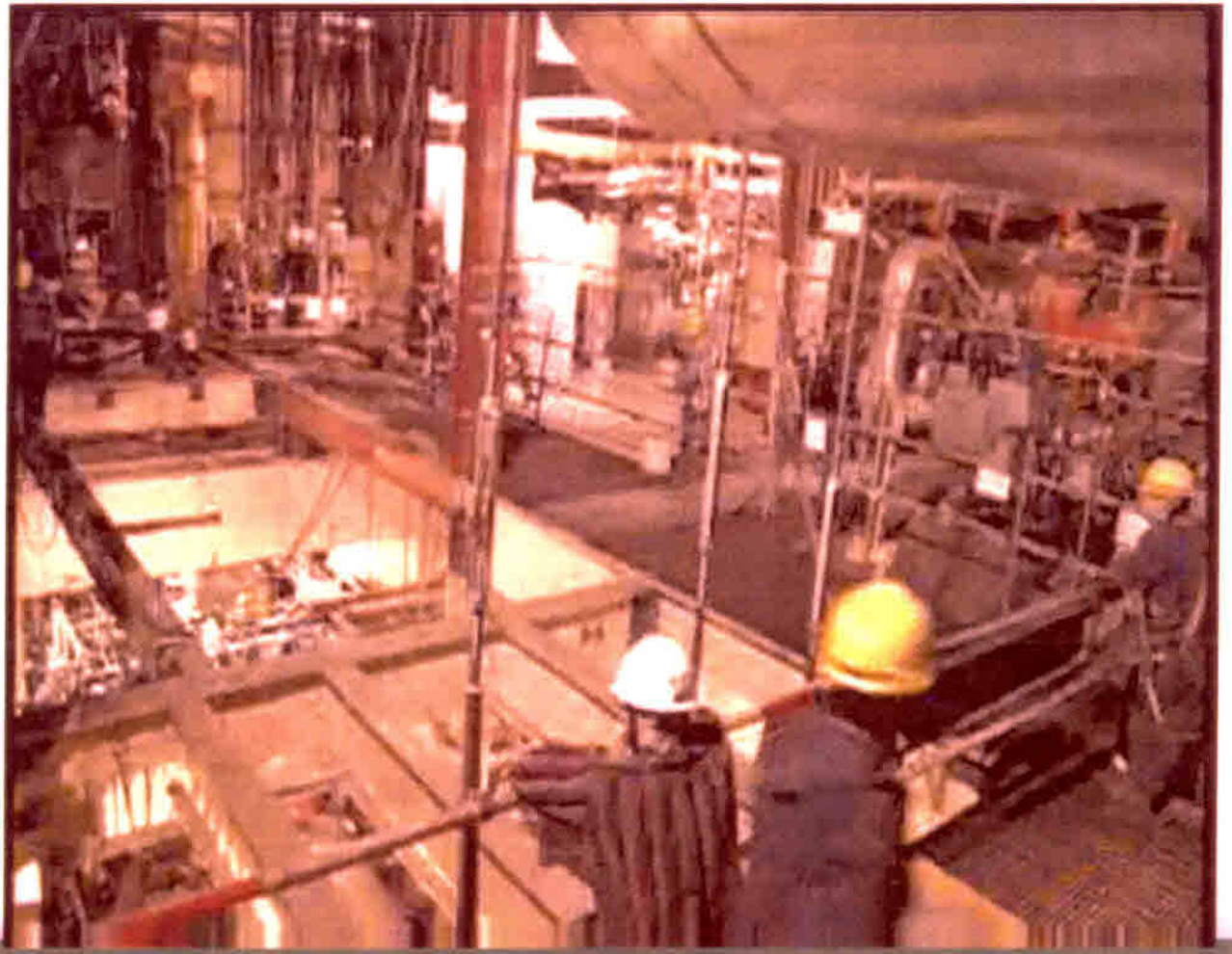
Condenser Replacement Ft. Calhoun

Modular Replacement (time lapse)



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Condenser Replacement Schedule

- FY-08 Path Forward
  - Complete Conceptual Study "Project Plan"
  - Complete independent Business Case by Huron
  - Commence R-19 Design Changes (Elect, Mech, Civil)
  - Information Memorandum for full project funding
  - Action Memorandum for full Project funding
  - Complete modular tube bundle Material Procurement Specification and award contract

- FY-09 Path Forward
  - Complete R-19 design modifications
  - Complete Turn-Key Contract process / award contract
  - Implement R-19 design modifications
  - Begin Turn-Key Contractor mobilization

Condenser Replacement Schedule

- FY10 Path Forward
  - Complete on-line design modifications
  - Complete R-20 Design Changes
- FY11 Path Forward
  - Receive Main Condenser modules on-site
  - Implement R-20 design modifications
  - Condenser module replacement
- FY-12
  - Post Outage Demob & Disposal

1/26/06

EXECUTIVE BOARD
RESOLUTION NO. 1423

A RESOLUTION APPROVING THE 2006 ENERGY NORTHWEST REFUNDING PLAN FOR PROJECT 1, COLUMBIA GENERATING STATION, AND PROJECT 3 AND EXTENDING COLUMBIA GENERATING STATION DEBT

The Chief Executive Officer reports that by Executive Board Resolution No. 1207, adopted September 27, 2001, the Executive Board approved the Energy Northwest September 2001 Refinancing Program, comprised of the refinancing of Project 1, Columbia Generating Station (Columbia), and Project 3 Bonds, and delegated certain responsibilities to Energy Northwest's Chief Executive Officer and Chief Financial Officer in connection with that program, and

The Chief Executive Officer further reports that the September 2001 Refinancing Program detailed the goals and objectives of the Refinancing Program implemented by Energy Northwest and the Bonneville Power Administration (BPA). That Refinancing Program contains the historical debt service savings goals and objectives for Callable Refunding Candidate Bonds and also contains the Debt Optimization Program description and objectives. The 2006 Refunding Plan reaffirms the above sections and proposes that the final maturity of Columbia debt be extended from 2018 to 2024, and

Based upon the recommendation of the staff and the Chief Executive Officer, the Executive Board finds that approval of the 2006 Refunding Plan, the reaffirmation of the authorities granted in Executive Board Resolution No. 1207, and the proposal that the final maturity of Columbia debt be extended from 2018 to 2024 are in the best interests of Energy Northwest and the electric ratepayers of the Pacific Northwest; NOW, THEREFORE,

IT IS RESOLVED that the Executive Board approves the 2006 Refunding Plan, reaffirms the authorities granted in Executive Board Resolution No. 1207, and approves the proposal that the final maturity of Columbia debt be extended from 2018 to 2024 in the following circumstances:

1. For new capital investments to their useful life up to 2024;

2. For the Columbia Debt Optimization Program debt in Fiscal Year 2006 of $105 million; and

3. For the Columbia callable/advance refundable debt in Fiscal Year 2006 of $350 million.

It is further resolved that the above approval is subject to the following conditions:

1. That adequate funding for Columbia license extension be provided for in the 2007-2009 BPA rate proposal as agreed to by Energy Northwest management;

2. That a joint BPA-Energy Northwest taskforce be created to address deferred maintenance issues for Columbia. A plan shall be prepared which addresses the implementation of necessary equipment upgrades and replacements, including but not limited to condenser replacement, feedwater heaters, and the digital electro hydraulic control system. The plan shall include a goal to minimize impacts to ratepayers both near and long-term. Such plan shall rely first on savings achieved by Energy Northwest activities and may include long-term debt financing if necessary; and

3. The taskforce shall proceed immediately and finalize its report to the Executive Board and other interested parties as soon as possible;

and the Chief Executive Officer, or his designee, is authorized and directed to take such actions as necessary to implement these actions, subject only to the contractual rights of the Bonneville Power Administration and the Participants' Review Board.

ADOPTED by the Executive Board of Energy Northwest this 26th day of January, 2006.

Chairman

ATTEST:

Secretary

APPROVED AS TO FORM AND LEGALITY:

Counsel

1/7/09

ENERGY NORTHWEST

Condenser Tube Size 00608601
Business Case

$2.1M decision

EAC Meeting
January 7, 2009
Dave Swank

EAC voted 1" to go with tube size

Today's Objective for EAC

- Present the 7/8" and 1" Condenser tube size options and associated Business Case
- Obtain an EAC decision based on the Business Case, Long Range Plan Commitments, and competing business needs

Team at Yuba right now ironing out the details

Assumptions

- YUBA will be the Condenser Module vendor — CGS is at 1¼" now.
- The vendor projected condenser back pressure difference between 7/8" and 1" tubes will be achieved (value is 2.37" Hg verses 2.40" Hg, or 0.03" Hg) — difference

base at 78°F circ water temp.

- Power production difference of 0.916MWe — based on best
- Debris caused tube clogging will be about the same for either size tube — so not a factor
- Tube plugging will be infrequent and thus will not impact the tube size decision. Smaller tubes, more tubes so plugging impact is less.

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Business Case Assumptions

- Cost of Power - $50/MWHr
- Plant Capacity Factor – 0.9
- MWH/Yr – 7,222
- Cost - $2,128,000.
- Escalation Rate – 3.5%
- Discount Rate – 6.5%
- Payment Period FY09 - 25%, FY10 – 50%, FY11 – 25%

Δ in cost 1" to 7/8"

still negotiating w/ Yuba on this.

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Business Case Results

- There is an 8-year payback period for the cost associated with the going from 1" to 7/8" tubes from YUBA

Recommendation

- Since the Condenser Project budget of $106.8M will be challenged by the project scope of work, and since the Long Range Plan targets for FY09, FY10, and FY11 are all being challenged by the scope of work identified for Columbia, go with the 1" tubes.

Yuba ~~getting~~ giving a better design

EAC voted to approve going with 1".

tube wall thickness the same.

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Condenser Replacement Project/ Project No. 00608601

EAC Meeting

January 31, 2007

Joe Frisco

Purpose of Presentation

- Present status of S&L Condenser study and business case
- Approval of recommended path
  - Options are dramatically different both in cost and installation
  - Path forward for this FY and next require option decision to proceed further

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Background

- Sargent and Lundy Main Condenser Upgrade Scoping Study completed in Dec of 2006
  - Condition assessment
  - Copper reduction options
  - Thermal performance analysis
  - Installation options and considerations
  - Budgetary estimates
  - Dose and fuel impacts
- Recommendations Summary
  - Do nothing option not a realistic option
  - Recommend replacement at earliest opportunity
    - Modular with Sea Cure or Titanium
    - Retube with Sea Cure or Titanium
    - Conduct cost benefit to determine most appropriate path

Vic message this morning from ANPO — fix your condenser.

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Executive Summary

PHC Project Ranking 16
Project Type Capital

Summary Cost Estimate

	FY07 $K					
	Base Case	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Current Estimated Capital Costs	$ 30,586	$ 54,512	$ 25,897	$ 30,586	$ 63,493	$ 80,933
PHC/EAC Approval						

Options Considered

Base Case - Delay condenser retube approximately 6 years to FY13 and then use Alternative 3
Option 1 - Retube with copper in FY09 and install deep-bed deminerlizers in FY11
Option 2 - Retube with stainless steel (Sea-Cure) in FY09
Option 3 - Retube with titanium in FY09
Option 4 - Retube with modular stainless steel bundles (Sea-Cure) in FY11
Option 5 - Retube with modular titanium bundles in FY11
Option 6 - Retube over 2 outages with titanium - not considered viable due to 1) outage penalties would double, 2) thermal expansion differences from different materials

drives you to 12-20

Recommended Option

Option 3 - Retube with titanium in FY09

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Cost Benefit Analysis – Results

Present Value Details - Magnitude and Sensitivity of Input Assumptions

	FY07 $M NPV					
Impact/Description	**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Installation Costs	$ (24.9)	$ (49.0)	$ (24.0)	$ (28.4)	$ (55.3)	$ (70.5)
Installation Outage Impacts/ Incl Dose	$ (24.6)	$ (24.9)	$ (32.7)	$ (32.7)	$ (85.0)	$ (85.0)
Chem Decon (incl dose)	$ (11.7)	$ (8.0)	$ (8.0)	$ (8.0)	$ (11.7)	$ (11.7)
Fuel Failure Risk	$ (5.8)	$ (3.0)	$ -	$ -	$ (3.0)	$ (3.0)
Projected Downpowers for Tube Leaks	$ (10.2)	$ -	$ -	$ -	$ (5.3)	$ (5.3)
Reduced Dose	$ 17.5	$ 19.4	$ 19.4	$ 19.4	$ 17.5	$ 17.5
(Derate)/ Increased Generation	$ (13.6)	$ -	$ (25.6)	$ (15.8)	$ 69.6	$ 69.6
Added ongoing Inspection Costs for Modular	$ -	$ -	$ -	$ -	$ (1.8)	$ (1.7)
Total	**$ (73.2)**	**$ (65.4)**	**$ (71.0)**	**$ (65.5)**	**$ (74.9)**	**$ (90.0)**

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Discussion of Options Considered

- **"Note: No Perfect Solution"**

- Base Case – Delays replacing copper and lowering dose
- Option 1 – Re-tube with copper in FY09 and install Deep beds in FY11 – does not seem reasonable to install this much capital equipment
- Option 2 – Technically very doable but difficult to monitor and inspect tube integrity with sea-cure material
- *Option 3 – Technically very doable - Recommended option*
- Option 4 – Technically extremely complex installation and Inability to monitor and inspect tubes integrity with sea-cure material
- Option 5 - Technically extremely complex installation

→ the best

PHC, 1½ hr discussion

Able; PT. Calhoun did modular - much similar condenser.

Chem. manager integrated in modular.

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Recommended Options

They put out a detailed memo.

- Sea Cure material selection NOT recommended by our materials engineers
  - Tube processing consideration – ability to find defects/complex material mix
  - Future inspection challenges – ability to find defects
  - Titanium proven performer in many more installations

There are people out there who are happy w/ Sea-cure.

Option 3 – pro's and con's relative to modular replacement

- Pros
  - Relatively Low Capital Costs
  - Easier Installation – can be accomplished in FY09
  - Technical and Installation risk - Lower then modular
  - Gets copper out of the plant the quickest
    - Getting dose reduction ASAP

Peach Bottom: only Boiler what done Modular.

- Cons
  - Summer Derate possible now and with Extended Power Uprate
    - Due to unknowns uprate not considered in business case
    - If/When EPUR occurs evaluate further for other mods to gain back potential losses
  - Muntz Metal tube sheet
    - Pullout testing recommended this FY
    - Validates our configuration and determines implementation strategy

10-15K → what kind of joint strength do you get. map want to machine to increase strength mock-up

Joe;
Power Uprate: he talked with
1.) difficult to predict amount.
2. when would you do it?
3.) there are things you could do to recover derates

⇒ So don't/didn't consider uprate - it was tabled

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Milestones

- **Near Term**
  - 2/15/07 – Determine FY07 and FY08 funding needs
    - Tube sheet pull out test
    - Engineering effort estimated by S&L $500K-1M
  - 4/20/07 – Develop bid specification for engineering effort
  - R18 – Re-tubing vendor walk downs
  - 7/1/07 – Award engineering contract

- **FY08**
  - 9/1/07 – Develop procurement specification
  - 2/1/08 – Place material order
  - 2/1/08 – Engineering complete

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Cost Benefit Analysis - Key Financial and Economic Considerations

- Total Capital Costs
- Outage Duration
- Value of Lost Generation
- Value of Increased Generation
- Uprate Capability
- Fuel Failure Risk
- ALARA

Key Assumptions/Qualifications

Note: All alternatives will result in condenser retube

Discount Rate		6.5%
Escalation		3.0%
Man-rem exposure costs $K/man-rem	$	25
FY09 Outage w/o Condenser (days)		35

validate

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Cost Benefit Analysis – Specific Assumptions

Other Cost Impacts Assumptions		FY07 $K					
		Base Case	Option 1	Option 2	Option 3	Option 4	Option 5
Radiation							
Radiation Impacts Retubing (man-rems)		12	12	12	12	60	60
Cost per Man-rem (FY07$K)		$ 25	$ 25	$ 25	$ 25	$ 25	$ 25
Total Radiation Impacts (FY07$K)		$ 300	$ 300	$ 300	$ 300	$ 1,500	$ 1,500
Installation Outage Impacts							
Incremental Outage Impact (Days)		33	25	33	33	85	85
Lost MWH from Outage Impact	1107	876,744	664,200	876,744	876,744	2,258,280	2,258,280
Annual Derate/Increase							
Lost MWH from Summer Derate		17,133	-	27,818	17,133	-	-
Increased Generation (MWH)						91,542	91,542
Additional Annual Inspection Costs							
Per Outage (FY07$K)		$ -	$ -	$ -	$ -	$ 220	$ 200
Chemical Decon		$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367
Radiation Impacts from Decon (man-rems)		15	15	15	15	15	15
Radiation Benefits for Copper Removal							
Man-rems Saved		50	50	50	50	50	50
Value of Man-rems saved (FY07 $K)		$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250
Fuel Failure Risk from copper							
Probability of failure Annually prior to retube post FY09		0.05	0.05			0.05	0.05
Cost of a failure							
Direct Cost (FY07$K)		$ 4,000	$ 4,000			$ 4,000	$ 4,000
Fuel Purchase (FY07$K)		$ 25,000	$ 25,000			$ 25,000	$ 25,000
Root Cause Analysis (FY07$K)		$ 4,000	$ 4,000			$ 4,000	$ 4,000
Radiation Costs of a failure (FY07$K)		$ 425	$ 425			$ 425	$ 425
Total Fuel Failure Costs (FY07$K)		$ 33,425	$ 33,425			$ 33,425	$ 33,425
Annualized Cost for Fuel Failure Risk (FY07$K)		$ 1,671	$ 1,671			$ 1,671	$ 1,671
Downpowers for Condenser Problems Post FY09							
Direct Costs (FY07$K)		$ 605				$ 605	$ 605
Annual Average Lost Generati	40	$ 2,358	Based upon 6 in the last 3 years due to condenser tube leaks			$ 2,358	$ 2,358
Total Downpowers Loss and Cost (FY07$K)		$ 2,963				$ 2,963	$ 2,963

No leaks projected?

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ESTIMATED COSTS BREAKDOWN

		FY07 $K					
		Base Case	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Capital Costs by Work							
Retube Condenser/Includes Disposal Costs		$ 28,061	$ 25,011	$ 23,759	$ 28,061	$ 58,250	$ 74,250
Deep Bed Demin		$ -	$ 25,000	$ -	$ -	$ -	$ -
Sales and Use Tax	9%	$ 2,525	$ 4,501	$ 2,138	$ 2,525	$ 5,243	$ 6,683
Total Capital Costs		$ 30,586	$ 54,512	$ 25,897	$ 30,586	$ 63,493	$ 80,933

PHC/EAC Approval

ENERGY NORTHWEST

Condenser Replacement Project
Module Fabrication Procurement

Action Memorandum 1079

October 22, 2008

Brian Berglin

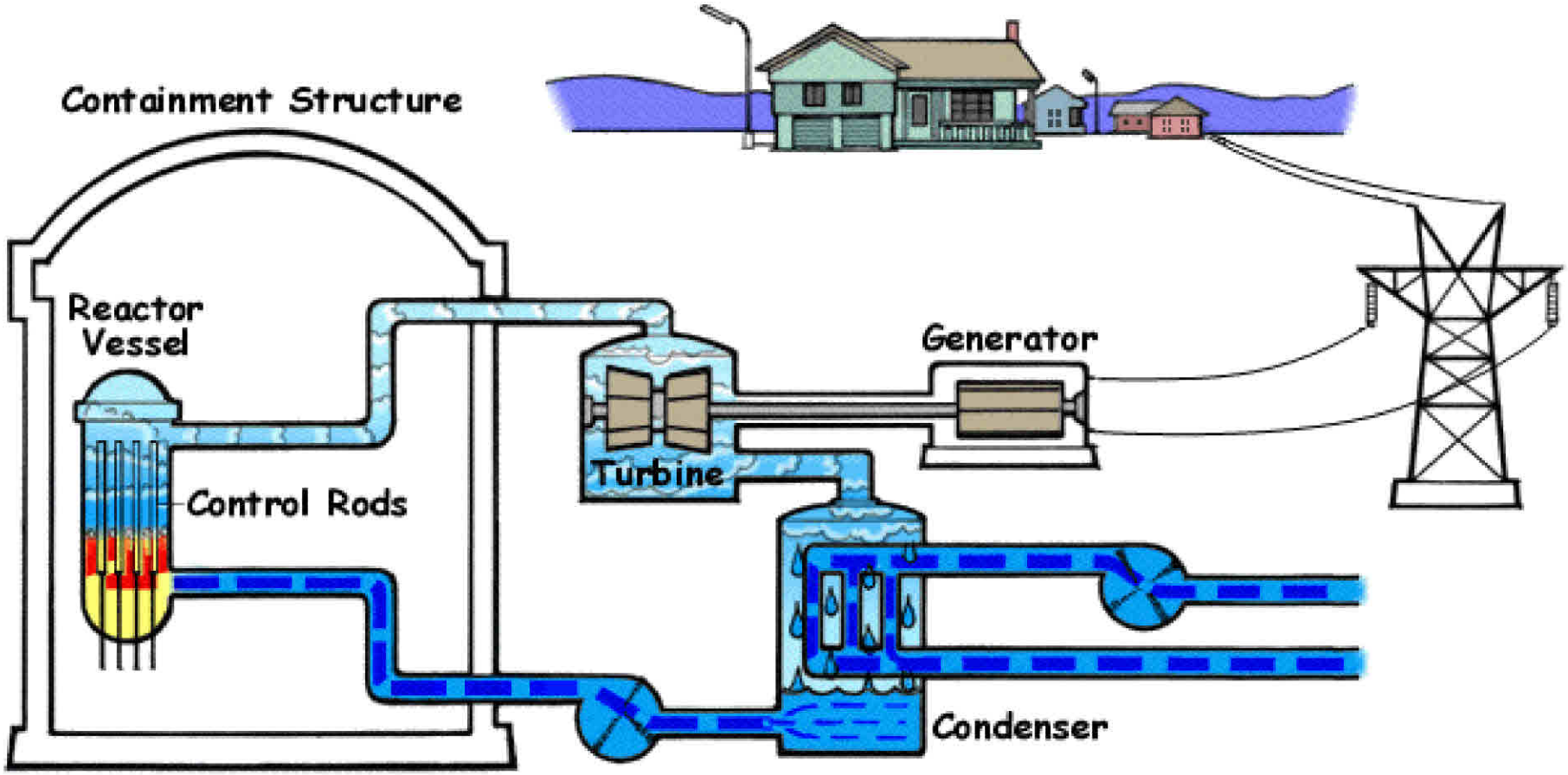
BACKGROUND

- Condenser Replacement Project split into two principal segments:
  - Design, fabrication and delivery of 12 ea replacement condenser modules (Request for Proposal (RFP) 651803)
  - Performance of tasks necessary to remove the existing condenser modules and installation of new condenser modules (RFP 651804)
- This Action Memo only addresses Module Fabrication
- RFP 651803 was issued on 05-23-08

BACKGROUND (continued)

- Initial bids received on 08-06-08
  - Thermal Engineering International (TEI)
  - Yuba Heat Transfer
  - Toshiba (Westinghouse)
- Project team performed plant site visits to all vendors and main sub-contractors
- Best and Final Offer issued on 09-29-08

BWR Steam Cycle

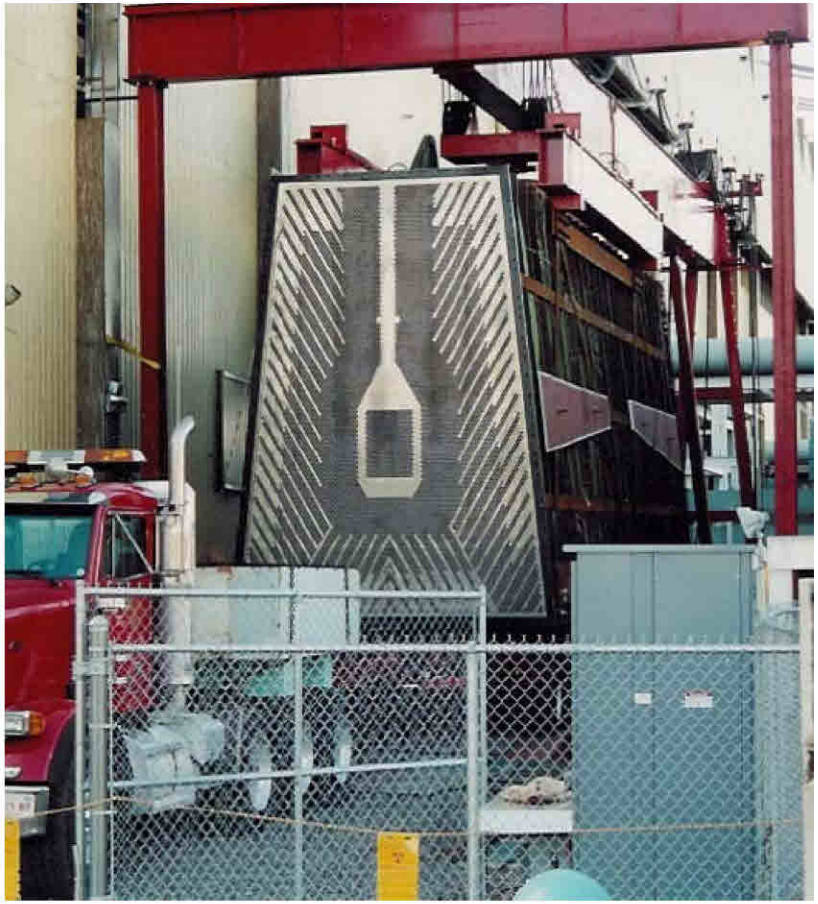


ENERGY NORTHWEST

Condenser Module Description (12 ea)

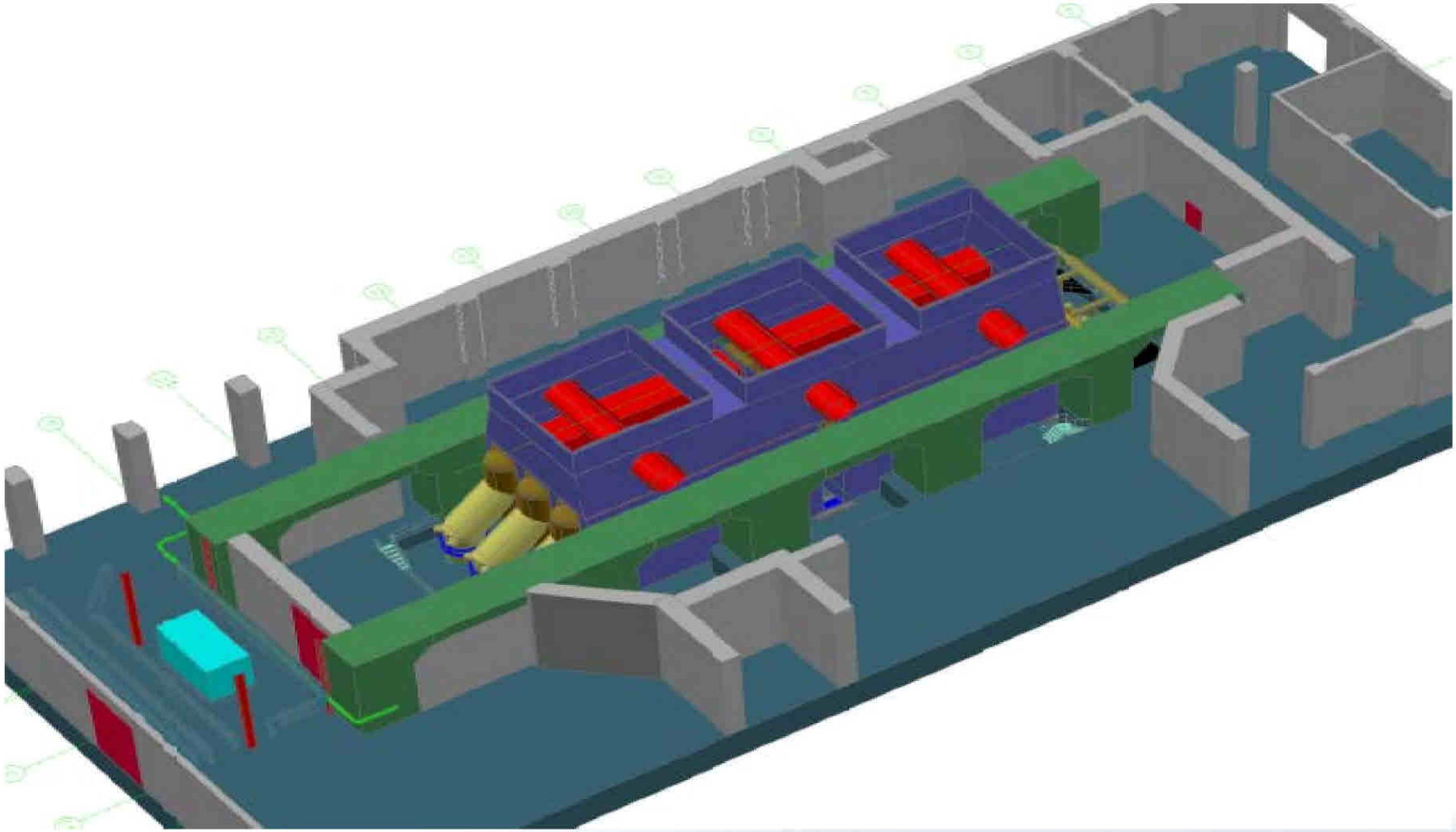
DESCRIPTION	EXISTING	PROPOSED
Surface Area	66,000 ft^2 (792,000 total)	Increased
Tube Material	Admiralty Brass	Titanium
Number of Tubes	4053 (48,636 total)	7166 (86,000 total)
Tube Length	50 feet	50 feet
Tube outside diameter	1-1/4 inches	7/8 inches
Design cleanliness factor	85% (actual 53%)	85%
Width	10 feet	10 feet
Height	12 feet	12 feet
Weight	220,000 pounds	180,000 pounds

One Main Condenser Module



ENERGY NORTHWEST

Main Condenser Project: 3D overview



ENERGY NORTHWEST

Discussion

- Best and Final Offers received on 10-09-08
- Reviewed by Source Evaluation Panel using weighted criteria
- TEI ranked to be the most advantageous both technically and the lowest cost
- Recommendation reviewed and approved by Contract Review Board on 10-15-08

Discussion (cont)

- Award of this contract will assist the Project team in:
  - Eliminating current design unknowns
  - Clarifying installation scope of work tasks needed

Discussion (cont)-module being removed

ENERGY NORTHWEST

Discussion (cont)-condenser interior shell

ENERGY NORTHWEST

Discussion (cont)

- Bids received were
  - TEI-$36.1M
  - Yuba-$36.9M
  - Toshiba-43.6M
- Estimates made on:
  - Performance Bond
  - Shipping

Recommendation

- Award Main Condenser Module Design, Fabrication and delivery RFP 651803 to TEI for $37,000,000.

ENERGY NORTHWEST

Information Memorandum 698
R-20 Installation Contractor
Condenser Replacement Project

Brian Berglin

Background

- Received bids from two Design and Installation Contractors in October 2008
  - Cost was too high and outside the Project's Long Range Plan
  - Contingency and uncertainty too high
- Used Site Support Contractor for R-19 interference removal and re-location work.

Background (Continued)

- Awarded contract to Yuba Heat Transfer to manufacture 12 new condenser modules
  - Delivery begins in May, 2010
  - Delivery ends in July, 2010
- Performed R-19 Design Engineering with Outside Engineering Company

Background (Continued)

- To minimize cost and reduce risk, contract strategy changed:
  - Energy Northwest to perform R-20 Engineering with Outside Engineering Company
  - Condenser Design is performed by the Condenser Module manufacturer Yuba
  - Limited this contract to Condenser Removal and Installation only
  - Multiple discussions with bidding contractors

Discussion

- Sent out Initial Request for Proposal (RFP) to bidders on 03-25-09
- Conducted Pre-proposal Conference with potential bidders on 04-10-09
- Received three bids on 05-08-09
- Two of three bids made the competitive range 05-11-09
- Both bidding contractors spent two days inside Condenser to obtain a first hand look of all the scope of work during the R-19 Outage.

Discussion (continued)

- Project Team met with each bidding contractor for additional discussions to clarify scope and answer bidders questions:
  - 07-09-Met with each contractor in Richland, WA
  - 08-09-Met with each contractor at Bethlehem, PA to discuss Module Manufacturing design and methods for removing the existing modules and installing the new modules.
  - 09-09 – Met with each contractor at Columbia Generating Station.

Discussion (continued)

- Issued Best and Final Offer (BAFO) RFP on 09-28-09
- Continuing to answer bidder questions formally through the Contracting Officer
- On schedule to receive BAFO's from bidding contractors by 11-02-09

Next Step

- Internal review panels to review RFP's and make a recommendation to the Source Selection Official (SSO) for award
- SSO to make final award determination recommendation to CEO and Executive Board
- Issue Action Memorandum recommending approval of selected contractor
- Obtain BPA non-disapproval letter allowing award to selected contractor

Next Step (continued)

- Present Action Memorandum on 11-19-09 to the Executive Board for approval.
- Issue contract or limited notice to proceed by 11-30-09 to selected contractor

Questions/Comments?

Columbia Generating Station Condenser Project Update & Request For Board Approval to Contract for Condenser Modules on RFP 651803

Dave Swank

January 21, 2009

R-19 Design & Planning

- Engineering design packages completed
- Work Order planning in progress and on schedule to be completed in 02-09

R-19 Implementation

- Site Support Contractor (SSC) will be used to perform R-19 interference removal work
- Pre-outage work identified and being scheduled and planned
- Outage work identified and being scheduled and planned

R-20 path forward

- Design and Installation bids
  - Procurement cancelled due to projected costs which are driven by scope uncertainty
- Initiating new Request for Proposal for the Cycle 20 and R-20 installation work only
  - New request may attract more bidders
  - R-20 scope clearly defined by performing module design R-19 walk downs
  - Bids will reflect clear scope and decreased risk
  - Scope restricted to implementation work only

Module Procurement

- Met with top ranked module vendor TEI to discuss final terms and conditions and module performance guarantees
- TEI was not able to provide details of how the modules would meet air removal, condensate inundation of tubes, or subcooling concerns
- TEI stated that the earliest answers could be available is late spring 2009
- Discussions with TEI suspended due to technical and schedule concerns

Module Procurement (Cont)

- Met with second module vendor, Yuba, to discuss terms and conditions and module design details
- Yuba provided satisfactory details of how the modules would meet technical requirements including air removal, condensate inundation of tubes, or subcooling issues
- Terms and conditions agreed upon
- Yuba now considered the top bidder based on a combination of technical and financial considerations

Module Procurement (Cont)

- Previous request to award contract to TEI was for $37,000,000 using 7/8” tubes.
- Business case was developed using Yuba’s design values and costs for 7/8” vs. 1” tubes
- Business case favors using 1” tubes
- EAC evaluated business case on 01-07-09 and decided 1” tubes will be used for the condenser.

Request for Board Approval

- Request for Board approval to award contract RFP 651803 to Yuba Heat Transfer for the condenser modules
- Contract value not to exceed $34.66M

Project Goals

- Keep within the Long Range Plan Budget
- Minimize R-20 Outage duration
- Minimize cost
- Obtain expected increase in electrical output from condenser replacement
- Meet Station Safety & Quality goals
  - No condenser leaks for several cycles
  - No FME problems for several cycles

ENERGY NORTHWEST

Action Memorandum 1109
R-20 Installation Contractor
Condenser Replacement Project

11-18-09

Brian Berglin

Background

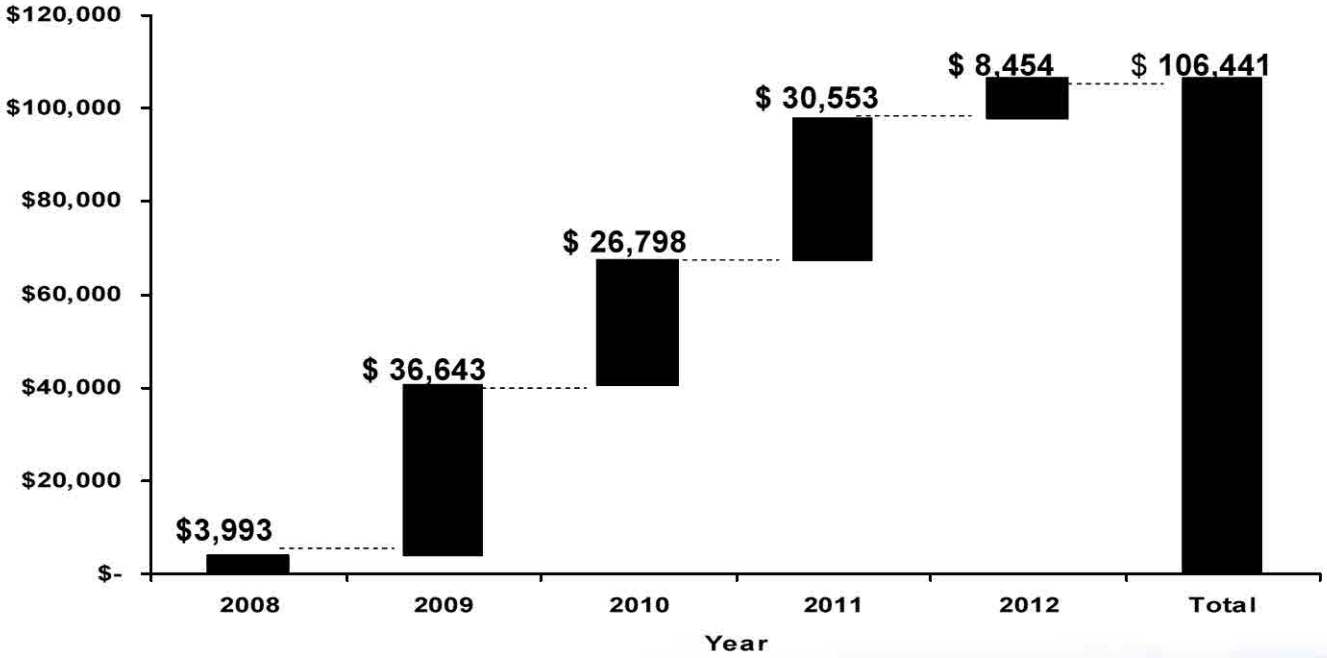
- Received bids from two Design and Installation Contractors in October 2008
  - Cost was too high and outside the Project's Long Range Plan
  - Contingency and uncertainty too high
- Used Site Support Contractor for R-19 interference removal and re-location work.

Background (continued)

Business Case to Executive Board on 03-26-08

Titanium Modular Replacement in 2011

Max	$ 4,769	$ 42,680	$ 31,819	$ 35,260	$ 10,827	$ 122,032
Min	$ 3,212	$ 30,795	$ 21,847	$ 25,685	$ 6,410	$ 91,171



(units in nominal USD thousands; values shown are the mean from Huron analysis)

ENERGY NORTHWEST

Background (Continued)

- Awarded contract to Yuba Heat Transfer to manufacture 12 new condenser modules
  - 1st condenser module 75% complete
  - Delivery scheduled for July 2010
- Performed R-19 Design Engineering with Outside Engineering Company

Background (Continued)

- To minimize cost and reduce risk, contract strategy changed:
  - Energy Northwest to perform R-20 Engineering with Outside Engineering Company
  - Condenser Design is performed by the Condenser Module manufacturer Yuba
  - Limited this contract to Condenser Removal and Installation only
  - Multiple discussions with bidding contractors

Discussion

- Sent out Initial Request for Proposal (RFP) to bidders on 03-25-09
- Conducted Pre-proposal Conference with potential bidders on 04-10-09
- Received three bids on 05-08-09
- Two of three bids made the competitive range 05-11-09
- Both bidding contractors spent two days inside Condenser to obtain a first hand look of all the scope of work during the R-19 Outage.

Discussion (continued)

- Project Team met with each bidding contractor for additional discussions to clarify scope and answer bidders questions
- Issued Best and Final Offer (BAFO) RFP on 09-28-09
- Received BAFO's from Contractors on 11-02-09
- Source Evaluation Panel (SEP) reviewed proposals from 11-03-09 to 11-05-09

Discussion (continued)

- Two bidder teams evaluated were:
  - Babcock and Wilcox
    - Barnhart Crane and Rigging
  - Tetra Tech
    - PCI Energy Services
    - Lampson Crane & Rigging
    - Morsey
    - Williams Industrial Services

Discussion (continued)

- Recommendation made by SEP to the Source Selection Official (SSO) for award to Babcock & Wilcox for the following reasons:
  - Key personnel & staffing plan
  - Very good safety record
  - Alternate bid was credible which included reduced outage duration and cost
  - Lowest R-20 Outage duration schedule
  - Lowest Cost

Discussion (continued)

- Long Range Plan (LRP) Status
  - Lowest bid was above Project Estimate
    - Heater Drain Piping re-routes scope
    - Vertical hot well supports need replacement
  - LRP budget of $106.8M is challenged
  - Outage Duration is shorter than planned
  - Projected results make business case more favorable
  - Project Team working to reduce Project costs

Next Step

- Recommend award of Main Condenser Removal and Installation contract RFP 655678 to Babcock & Wilcox for the fixed price amount of $32,845,734.00
- Issue contract or limited notice to proceed by 11-30-09 to selected contractor

Questions/Comments?

ENERGY NORTHWEST

Columbia Generating Station Condenser Project Update

Brian G. Berglin

December 10, 2008

Module Procurement

- Met with module vendor to discuss terms and conditions and module design details
- Finalizing Terms and Conditions of Contract

R-19 Design & Planning

- Engineering design packages on schedule to be completed next week
- Work Order planning in progress and on schedule to be completed in 02-09

R-19 Implementation

- Site Support Contractor (SSC) will be used to perform R-19 interference removal work
- Pre-outage work identified and being scheduled
- Outage work identified and being scheduled
- Work with module vendor to perform all necessary R-19 condenser work to minimize R-20 outage duration

R-20 path forward

- Current Design and Installation bids
  - Procurement being cancelled due to projected cost which is driven by scope uncertainty
- Initiating new Request for Proposal for the Cycle 20 and R-20 installation work only
  - New request may attract more bidders
  - R-20 scope clearly defined by performing module design and walk downs during R-19 outage
  - Bids will reflect clear scope and decreased risk
  - Scope restricted to implementation work only

R-20 path forward (continued)

- Utilize Columbia existing engineering support for remainder of the engineering work
  - Module Vendor performing all the design of the Condenser module removal/installation
- Pursue disposal cost reductions through recycling of the copper tubes

Project Goals

- Keep within the Long Range Plan Budget
- Minimize R-20 Outage duration
- Obtain expected increase in electrical output from condenser replacement
- Obtain station Safety & Quality goals
  - No condenser leaks for several cycles
  - No FME problems for several cycles

ENERGY NORTHWEST

Information Memo 680
Condenser Replacement Project

Brian Berglin

Purpose

- To inform the Executive Board of the upcoming Action Memorandums
- Provide an overview of the business case
- Provide current status of the project

Overview

- Performed Conceptual Study
- Performed Business case
  - Based upon $106M +/- 25%
  - Results concluded module replacement had greatest Net Present Value (NPV)

Business Case Overview

Brent Ridge

Project Status

- Planning
  - Perform work over two outages
    - R-19 – Remove Interferences
    - R-20 – Replace Modules
  - Separate procurements into two parts
    - Modules – RFP 651803
    - Design & Installation – RFP 651804
  - R-19 Design Engineering started per Action Memorandum 1050

Project Status (Continued)

- Design
  - R-19 Design Engineering 40% complete
    - Interferences
    - Load Path Analysis
  - R-20 Engineering 0% complete – Module vendor input required

Project Status (Continued)

Procurement

Activity	Estimated Dates	
	Module	Installer
Issue Request of Proposal	Complete	Complete
Pre-bid Conference	Complete	Complete
Proposals Due	Complete	Complete
Visit Vendors	09-24-08	
Offeror's Presentations		Complete
Request Best & Final Offer	09-29-08	Complete
Best & Final Offer	10-07-08	10-07-08
Contract Execution	11-25-08	10-30-08

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Project Challenges

- Potential increase in the Design & Installation Cost
- Potential to reduce the R-20 outage duration
- What are we doing
  - Challenging the contractor to reduce cost:
    - Reduce contingency
    - Identify high risk areas for mitigation
    - Provide alternate methods of performing the work more efficiently
  - Project team reducing the scope of the project
  - Revising options in contract to pick and choose scope awarded to achieve the lowest possible cost

Conclusions

- R-19 Design Engineering activities on schedule
- Procurement of Modules is in progress
  - Modules can be delivered on time
  - Modules estimate is consistent with estimate
- Design & Installation cost is a challenge
- Condenser replacement is still a viable option

Questions/Comments?

From: RAPACZ, ANDREW J. <AJRAPACZ@energy-northwest.com>
Sent: Wednesday, May 28, 2008 5:09 PM
To: Rapacz,Andy (BPA) - PGC-RICHLAND
Subject: FW: Main Condenser Scoping Document
Attachments: 05-22-08 Main Condenser Project Scope of Work R1.doc

---

From: BERGLIN, BRIAN G.
Sent: Wednesday, May 28, 2008 5:09:19 PM
To: GAMBHIR, SUDESH; ATKINSON, DALE K.; LYNCH, THOMAS A.;
RAPACZ, ANDREW J.; RIDGE, BRENT; SMALLDRIDGE, BRADLEY A.;
FRISCO JR, JOSEPH M.; PAGEL, LYNNE A.; BEKHAZI, JOHN E.; SWANK, DAVID A.
Cc: BERGLIN, BRIAN G.
Subject: Main Condenser Scoping Document
Auto forwarded by a Rule

This email provides the Main Condenser Scoping Document (attached) requested at the 5-19-08 Steering Committee Meeting.

Brian

From: RAPACZ, ANDREW J. <AJRAPACZ@energy-northwest.com>
Sent: Monday, January 29, 2007 8:29 AM
To: Rapacz,Andy (BPA) - PGC-RICHLAND
Subject: Condenser Replacement 1-30-07 for BPA.xls - Business Case analysis - CBA
Attachments: Condenser Replacement 1-30-07 for BPA.xls

From: INDALL, CHRIS J.
Sent: Monday, January 29, 2007 8:28:57 AM
To: RAPACZ, ANDREW J.; BENTRUP, PAUL E.
Subject: Condenser Replacement 1-30-07 for BPA.xls
Auto forwarded by a Rule

Bear

Would you please share this with others at BPA who need this

Chris

<<Condenser Replacement 1-30-07 for BPA.xls>>

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From: RAPACZ, ANDREW J. <AJRAPACZ@energy-northwest.com>
Sent: Friday, April 25, 2008 9:14 AM
To: Rapacz,Andy (BPA) - PGC-RICHLAND
Subject: FW: Condenser - deep bed alt-01-14-08 Joe Frisco.doc - Follow-up infor.
Attachments: Condenser - deep bed alt-01-14-08 Joe Frisco.doc

---

From: INDALL, CHRIS J.
Sent: Friday, April 25, 2008 9:13:32 AM
To: RAPACZ, ANDREW J.; SMITH, PHILLIP E.; BENTRUP, PAUL E.; SHERMAN, ROBERT N.
Cc: THIEDERMAN, DAVID B.
Subject: Condenser - deep bed alt-01-14-08 Joe Frisco.doc
Auto forwarded by a Rule

Andy/All

Here is some followup information regarding deep-bed demineralizers.

Chris

<<Condenser - deep bed alt-01-14-08 Joe Frisco.doc>>

From: RAPACZ, ANDREW J. <AJRAPACZ@energy-northwest.com>
Sent: Monday, November 27, 2006 7:56 AM
To: Rapacz,Andy (BPA) - PGC-RICHLAND
Subject: FW: Resolution No. 1445 - Plant Life Extension and Equipment Reliability
Attachments: Document.pdf

From: BARWICK, SUSAN L.
Sent: Monday, November 27, 2006 7:56:00 AM
To: RAPACZ, ANDREW J.
Subject: FW: Resolution No. 1445
Auto forwarded by a Rule

Signed copy of Res. 1445 per your request.

Thanksgiving was great; hope yours was too!

Susan L. Barwick
Board Relations Specialist
Energy Northwest
Mail Drop 1040
P.O. Box 968
Richland, WA 99352
(509) 372-5226
(509) 372-5014 (fax)
slbarwick@energy-northwest.com

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From: Smith,Phil (BPA) - PGC-RICHLAND
Sent: Friday, February 23, 2007 1:55 PM
To: 'FRISCO JR, JOSEPH M.'
Cc: Rapacz,Andy (BPA) - PGC-RICHLAND; Sherman,Bob - PGC-RICHLAND; Bentrup,Paul E (BPA) - PGC-RICHLAND
Subject: RE: End of Life Projection For the main condenser

Thanks Joe. We would like to meet and discuss the life issue. We think it would be a worth-while discussion. Our request for a 6 or 8 year delay, the case you guys ran for us, was based on our understanding that we'd reach condenser limits in 8 to 10 years. The HEI chart of condenser life suggests we could go a whole lot longer than that. That gives us a bit of a pause as we do our due diligence on the condenser replacement. If there are 23-years left on the condenser life, no indications of copper effects on fuel cladding, dose reductions primarily from Co reduction and chemical decon, fuel failures and condenser tube failures due to poor FME control, and, if good maintenance and trending of condenser performance continues, I think one has to ask, why assume "something" has to be done right now?

-phil

PHILLIP E. SMITH
Professional Engineer - Nuclear, CM
Bonneville Power Administration
North Power Plant Loop
Richland, WA 99352
509-372-5130 voice
509-372-5766 fax

From: FRISCO JR, JOSEPH M. [mailto:jmfriscojr@energy-northwest.com]
Sent: Friday, February 23, 2007 10:50 AM
To: Smith,Phil - PGC-RICHLAND
Cc: Rapacz,Andy - PGC-RICHLAND
Subject: RE: End of Life Projection For the main condenser

Phil - be more then happy to meet, although I am not sure how this is significant. Recall we ran the business case with a 6 or 8 year deferral at your request. The actual end of life of the condenser in my opinion did not factor in othere then to know that it was coming before end of current license - the conclusion being that we would have to do something, it is a question of when. I still think the drivers of dose, potential downpowers and copper levels are the compelling short term drivers.

Let me know if you still want to meet.

thx - Joe

From: Smith,Phil - PGC-RICHLAND [mailto:pesmith@bpa.gov]
Sent: Thursday, February 22, 2007 3:48 PM
To: FRISCO JR, JOSEPH M.
Cc: Rapacz,Andy - PGC-RICHLAND
Subject: FW: End of Life Projection For the main condenser

Joe,

Given the info below, we would like to setup a meeting with you to discuss how this was incorporated into the business case assumptions. Thanks.

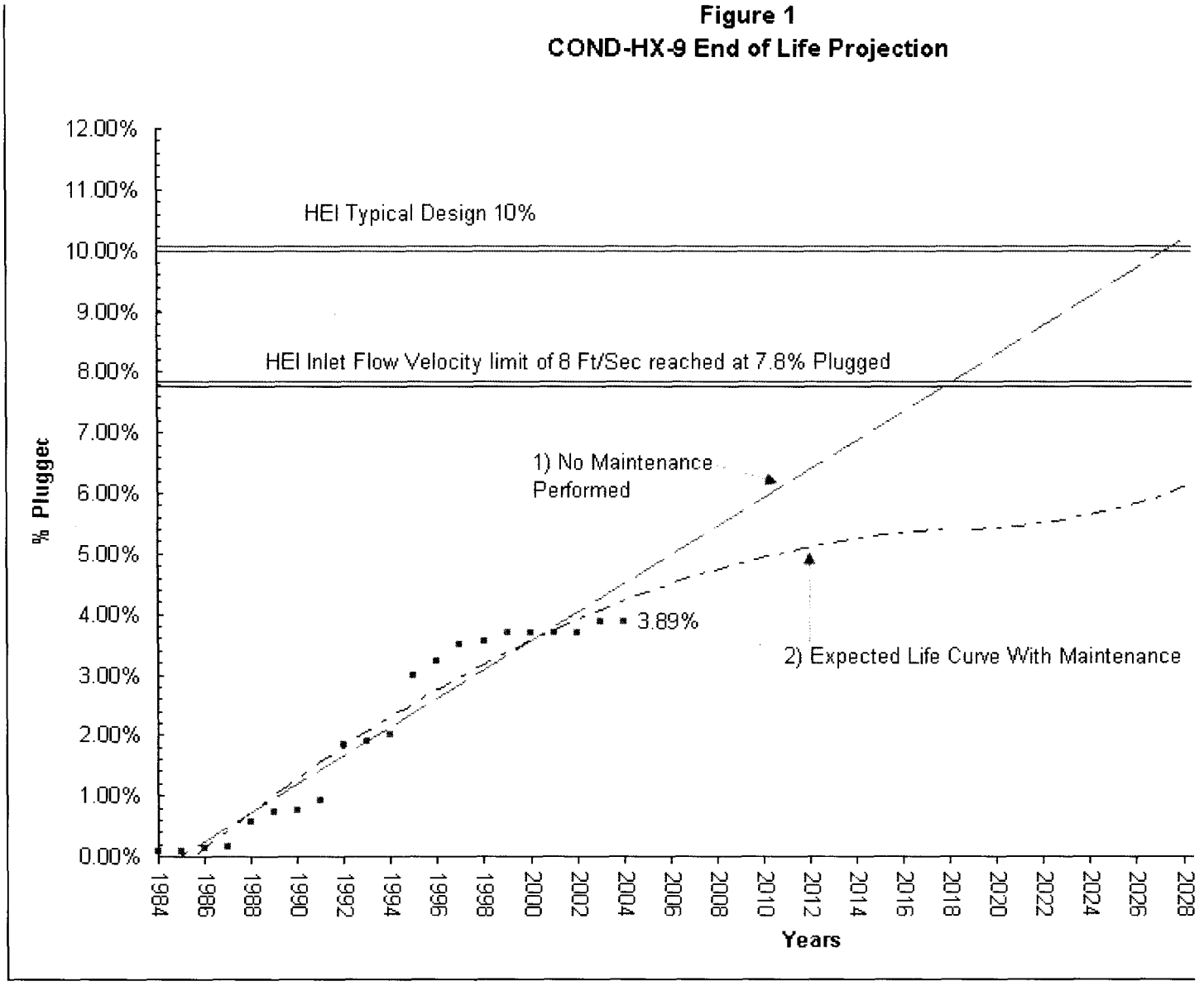
-phil

PHILLIP E. SMITH
Professional Engineer - Nuclear, CM
Bonneville Power Administration
North Power Plant Loop
Richland, WA 99352
509-372-5130 voice
509-372-5766 fax

From: LASALLE, JOHN R.
Sent: Thursday, January 25, 2007 5:15 PM
To: OXENFORD, W. SCOTT; LYNCH, THOMAS A.; KING, CARL M.; KHANPOUR, ABDOLLAH; BEKHAZI, JOHN E.; BELCHER, SAMUEL L.; HOGUE, RONALD W.; BORLAND, INGE M.
Cc: ERWIN, THOMAS M.; ADAMI, BRIAN M.; FRISCO JR, JOSEPH M.; WOODS, LEVI J.; TWOMEY, JOHN D.
Subject: End of Life Projection For the main condenser

There has been a lot of speculation regarding the end of life for the condenser and I attempted to frame the perspective with a projection of the life curve. I use the HEI design criteria to help define the limits based on increased flow rates and uniform thinning resulting in exceeding the design tube deflection towards the end of life.

This is a best guess on the end of life projection for the condenser tubes. This chart shows the actual % of tubes plugged and a regression through the data. With limiting condition being flow rate and uniform thinning at the tail end of the life cycle. No consideration for loss or unit de-rate has been assumed. The 7.8% plugged should be considered to be the limit for useful life. The range for the condenser end of life should be considered to be between 2018 worst case and 2033 best case. Obviously plant operation chemistry and maintenance determine the end point. The emergence of additional SCC or gross steam damage can easily change this outlook and eat up remaining margin rapidly.



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From: OXENFORD, W. SCOTT <WSOXENFORD@energy-northwest.com>
Sent: Tuesday, July 18, 2006 10:21 AM
To: Rapacz,Andy (BPA) - PGC-RICHLAND
Cc: PARRISH, JOSEPH V.; CADWELL, BEVERLY A.; CARLSON, DANIELE R.
Subject: RE: Sargent & Lundy Condenser Study

Andy,

There will be some interim discussions as the study is developed, but this is much less formal than the 30%, 60% reviews. I do not consider them to be indicative of a firm position and too early for BPA or my level to get involved.

I do not expect to authorize release of the report until it is reviewed and evaluated by ENW management. IAW our Net Billing agreement, we should be making an informed technical decision based on prudent utility practice. Once we have decided on a technical direction, we will then provide this information to our staff, board and BPA.

It is important that we avoid conclusions at an individual contributor level or based on preliminary reports or hearsay. Control of the report is one way to minimize this potential.

If you have concerns, please let me know.

Scott

From: Rapacz,Andy - PGC-RICHLAND [mailto:ajrapacz@bpa.gov]
Sent: Monday, July 17, 2006 3:34 PM
To: OXENFORD, W. SCOTT
Subject: Sargent & Lundy Condenser Study

Scott,
Thanks for the follow-up.
I guess I'm a little surprised that there won't be a midpoint (or there-a bouts) check in with S&L.
I'm assuming you will be sitting down with S&L at the end of their effort then, and going over their conclusions and report. It would be helpful if we could sit in on those discussions/reviews, so I'm hoping we can do that. It would be beneficial for us to clearly understand, along with you and your staff, the S&L conclusions and recommendation.
thanks,
- Andy

From: RAPACZ, ANDREW J. [mailto:AJRAPACZ@energy-northwest.com]
Sent: Sunday, July 16, 2006 9:44 PM
To: Rapacz,Andy - PGC-RICHLAND
Subject: FW: Condenser Study

From: OXENFORD, W. SCOTT
Sent: Sunday, July 16, 2006 9:43:45 PM
To: RAPACZ, ANDREW J.
Cc: KHANPOUR, ABDOLLAH; BOYNTON, SCOTT A.; DEMYER, TANYA M.;

CARLSON, DANIELE R.
Subject: Condenser Study
Auto forwarded by a Rule

Andy,

As I expected, there are not any interim milestones for the S&L Condenser Study. Additionally, we will be assigning a project manager in the near-term to alleviate the project responsibilities from Levi. Upon receipt and review of the study by CGS management, we will provide you a copy. We will be prepared to release the report before budget decision time.

If you have any questions, feel free to ask.
Scott

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ENERGY NORTHWEST ANSWER TO BPA QUESTIONS
CONDENSER PROJECT
03-14-08

Request from Andy Rapacz

From: Rapacz,Andy - PGC-RICHLAND [mailto:ajrapacz@bpa.gov]
Sent: Friday, March 14, 2008 11:53 AM Pacific Standard Time
To: GAMBHIR, SUDESH
Cc: Sherman,Bob - PGC-RICHLAND; Smith,Phil - PGC-RICHLAND
Subject: Condenser replacement discussion on March 14th

Sudesh,
I received your voice mail regarding topics for our discussion today on the Condenser replacement project.

EN has been working over the last 6 months, or more, on the actual replacement effort. We've have meetings with you to discuss the need/justification for the project and the cost benefit analysis/business case (which we're still looking at). But we've not had any significant discussions about project implementation itself. We are basically in the dark on that aspect.

What I would like to accomplish today is for us to gain an understanding of the what, how, when, where, etc. of the replacement itself. As you and I discussed, this may mean more than one meeting, but I'm hopeful we can have a good start today. As was previously discussed in some of the BPA/EN senior management meetings, we'd like to work with you to see if there are ways to reduce the costs of the Project or shorten the implementation time during actual installation.

At some point BPA will need to take non-disapproval action on the contracts. We'd like to have sufficient understanding of these to enable our action to occur in a timely manner to support the overall Project.

So as an example, some things we'd like to understand include;

Q: schedule of implementation (summary & detailed)
- R-19 Design Packages & Work Order Planning
- Award Main Condenser contract
- R-19 implementation
- R-20 Design Packages, Work Order Planning and Implementation

Q: what work will be done in each outage
- R-19 Implementation
  - Clean Main Condenser Hotwell
  - Install rail supports between hotwell false bottom and concrete foundation (EC 6834)
  - Provide condenser hotwell access hatches (personnel, equipment and services) (EC 6834)
  - Remove/reroute travel path interferrencesEC #6693
    - West concrete wall removal & temp shielding
    - Relocate 3" CAS pipe
    - Relocate 2" Service Air line
    - Install Gantry Crane in condenser bay

        - Relocate HWC Air Injection Skid
        - Relocate H2 piping outside TG building
        - Relocate Power/Control cables outside TG building
        - Relocate 12" Cond Short Cycle Return pipe
        - East side concrete wall removal
        - Relocate 1½"& 1" DW and 6" FP pipes
        - Modify FP CO2lines
    - Condenser Performance Monitoring (ASME PTC 12.2 Testing Code)
        - Pressure Instruments in the main condenser shell (EC 6692)
        - Circ Water Outlet Temperature Instruments -18
        - Circ Water Ultrasonic Flow Transducer – 1
- R-20 Implementation
    - On Line
        - Security Access Modifications
        - Extended Temporary RCA Building on West Side of Turbine Building
    - R-20
        - Air Removal
        - Condenser Modules

Q: what is the overall strategy - how will modules be moved out/back in

- The Condenser Team is evaluating: will likely be driven by the bid process
    - module removal or
    - pulling all the tube and cutting up the tubesheets and support plates
- Benchmarking trips (Ft Calhoun & Peach Bottom)
- Interviewing consultants with prior condenser replacement experience

Q: what is the contracting strategy (turnkey - multiple contractors - incentives/penalties

- R-19 Design & Planning (in progress)
    - Sargent & Lundy – R-19 Design Engineering
    - WEC – R-19 Performance Monitoring Design
    - Planning – Energy Northwest
- Design and Installation Contractor (R-19 Installation-Phase 1, On-line-Phase 2, R-20-Phase 3 based upon performance of previous phases)
    - RFP begun
    - R-19 Implementation
    - On-line Design and Implementation
    - R-20 Design
    - R-20 Implementation
- Condenser Modules
    - Separate bid from Design and Installation Contractor
    - Experienced in saving $
    - Looking at global bidders
- Site Support Contractor (optional, this has worked successfully in the past)
    - Scaffolding
    - Temp power, water, air
- Contractors will be incentivized for good performance and penalized for poor performance

Q: procurement strategy for material and modules (- module delivery)

- Module Procurement
    - Award contract – November 2008

- Complete Design – May 2009
- Tube Delivery – November 2009

- Module Delivery – June 2010

Q: what challenges are you facing

- Module Removal – Pull or Dismantle
- Rail System Configuration
- East Water Box – Remove or Rework In Condenser Bay
  - Remove
    - Relief Valve Testing Facility Move
    - East Condenser Bay Access
  - Rework In Condenser Bay
    - Smaller East Condenser Bay Access or none at all
    - Lower Probability Relief Valve Testing facility would have to be moved
    - Re-coating inside of water box in RCA
- Ingress / Egress- Facility Addition To PAAP
- Main Condenser Facility – TG Building RCA Extension
- Steam Jet Air Ejectors (SJAE) piping reroute
- Sand Blast / Coating Facility for water box coating
- Project decisions impacted by not having a Turnkey Contractor on site — This guy could be helping them out

Q: contingency planning

- Hotwell drain flanged connections will be installed for cleaning up water through a separate filtered system should using the plant demin filters become an issue. — After the job is complete, how do you clean-up

Q: disposal of old modules

- Burying is estimated in the existing plan • Some concern about legacy issue
- US Ecology
- Salvage or recycle may be an option
- 885 Tons of Copper
- $4.3M salvage of copper (share with vendor)
- Contamination Issues
- Perma Fix is local contractor

Q: design changes; who?

- Sargent and Lundy (S&L) providing mechanical, civil, structural designs
- Westinghouse providing electrical designs

Q: what work schedule; 24-7?

- 24-7 expected with potentially a rolling 6-day work week during the outage
- Normal 8-9 work schedule except OT when required (Project is fast track)

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INTEROFFICE MEMORANDUM

DATE: June 12, 2007

TO: J.L. Lewis, Reactor/Fuels Engineering Manager (PE26)

FROM: S.H. Bian, Fuel & Core Design Group Lead (PE26)

SUBJECT: Visual Results of R18 Fuel Inspection

REFERENCE:

1. EN IOM EN2-RXFE-06-037, DIC 554.2, "R18 Irradiated Fuel Inspection Scope," 12/19/06
2. AREVA Report 05-21 "Columbia Generating Station R17 Fuel Exam," File # 57-FS-05-47-01, May 2005
3. Email, N. Carr (AREVA) to EN, " R18 Fuel Inspection DVDs," 6/6/07

1.0 Introduction

R18 fuel inspections were completed on May 31, 2007. Six bundles were inspected. The scope included visual inspections, oxide measurements and crud collections from two bundles, visual and oxide measurements on two bundles and visual only on two bundles, all with ATRIUM-10 design. The bundle ID and inspection scopes are given in Table 1. The scopes for individual rods from four bundles (oxide measurement and crud collection) are given in Table 2.

The original scope called for visual inspection of six bundles (see Reference 1). Due to the outage schedule constraint, it was decided to visually inspect two out of the six bundles. This would not affect the quality of the data for an adequate evaluation of ATRIUM-10 performance. Important and detailed information was obtained from the four bundles as listed in Table 2, where individual fuel rods were pulled, washed, visually examined and measured for oxide thickness.

The analysis that follows is limited to an evaluation based on visual inspections. The final results on oxide thickness will be available at a later date by the fuel vendor. Crud analysis will be performed by AREVA and results will be published in 2008.

2.0 Visual Evaluation of ATRIUM-10 Bundles

The six ATRIUM-10 bundles inspected are UDJ231, UDJ223, UDJ175, UDH280, UDH010 and UDH056. The first three bundles were loaded in R17, the last three were loaded in R16. The assembly burnups are given in Table 1. Three fuel rods were pulled from each of the four bundles (UDJ231, UDJ223, UDH280, UDH010) for detailed examination in the Individual Rod Inspection Station (IRIS), including visual and oxide measurements.

2.1 Twice-Burned ATRIUM-10 Visual (Bundles UDH280 and UDH010)

Both UDH280 and UDH010 are twice-burned bundles with a burnup of 41.9 GWd/MTU and 42.9 GWd/MTU respectively. These two bundles were also examined in R17 (Reference 2).

Figure 1 shows Bundle UDH280 Rod C2 after washing at the 120" location (i.e., about 30" from the bottom of the rod, where the crud is typically the thickest) in the IRIS. For a diagram of rod arrangement and designation, see Figure 8, which applies to the UDH bundles inspected in R18. For the UDJ bundles inspected in R18 there are only 14 NAF (i.e., Gd) rods in these bundles, unlike what is shown in Figure 8. That is, Rod H8 is not an NAF rod. As can be seen, the fuel surface is smooth, with no oxide or crud spallation.

There is a light indication of nodules (with no thickness) at the natural uranium zone at the lower end of the rod after washing, i.e., bottom 6 inches of the rod. Otherwise the rod is shining and smooth in this bottom zone.

Note that Rod C2 in UDH280 is a 6.5% Gadolinia (Gd) rod with a Low Temperature Process (LTP) cladding. For comparison, a similar rod (K3 with 6.5% Gd with LTP cladding) on the same bundle as it appeared at the end of Cycle 17 is shown in Figure 2. Rod K3 was not inspected during this outage because crud was collected on the rod in R17 and it would give an incorrect oxide thickness measurement if it were measured at the site of R17 crud collection during this outage.

Another Gd rod inspected is Bundle UDH010 Rod K3. It is a 7.0% Gd rod with a late beta quench heat treatment. It showed no anomalies after brushing. This rod was examined in R17. In both R17 and R18 examinations, the rod looked normal. Figures 3 and 4 compares the same rod in Span 1 (between Spacers 1 and 2) after washing, one was taken in R18 and one in R17. The oxide thickness data for this rod is being reduced by the fuel vendor, AREVA. When the oxide thickness is available, it will give us an idea about the rate of surface corrosion by comparing it to the oxide thickness measured in R17.

Also observed on all rods are the typical dark spots under spacer locations where the spacer springs were in contact with the fuel cladding. Again, this is normal.

During the R17 inspection, a dark spot was noted on Bundle UDH010 Rod G10 (see Fig. 27 in Reference 2) which was not at a spacer location. Evaluation was made at the time regarding the cause of the dark spot and it was concluded that the spot was not a cladding perforation. This was confirmed by Cycle 18 operation with no indication of fuel failures. This rod was visually inspected again in R18 and no dark spot was found.

Other rods (UO2 rods) individually inspected on these two bundles had normal appearances (see Table 2 for rods inspected).

One part length fuel rod (PLFR) K2 in UDH280 was visually inspected "in-situ". This was done by first removing Rod L2, thus exposing K2. This approach of visually inspecting Rod K2 without pulling it out and putting it on IRIS was adopted because, as a PLFR, pulling the rod out would involve a risk of not being able to re-insert it back into the bundle. The PLFR is interesting to us because of it being a part length rod.

Figure 5 shows the PLFR K2 (second rod from right) before brushing. Figure 6 shows the same rod after brushing with Scotch Brite. As can be seen in Figure 6, there is a pattern below Spacer 6 in the rod surface. AREVA evaluated this pattern and made the following conclusions (Reference 3):

- Loose fluffy red crud is absent inside the crud pattern.
- The pattern is not completely around the rod, but is situated preferentially in one direction on the rod. This may be due to inefficiency in crud removal or easier crud removal on the surface of the crud pattern.
- No spalling is evident inside the crud pattern.
- The surface material inside the crud pattern doesn't appear to have appreciable thickness.
- No periodicity is present inside the crud pattern (i.e., repeating features within a pellet length or other dimension).
- Features inside the crud pattern appear to be random in shape and placement, and the pattern widens with upward axial position.
- This pattern appears to be a concentration of crud spots that were revealed when the loose fluffy crud was removed in brushing the rod. The crud pattern on rod K2 is similar to features observed at other reactor sites.
- The location of this crud pattern is at the top of Rod K2 and is therefore almost entirely within the fuel rod plenum where the cladding surface is relatively cold compared to the fueled region. Oxide thickness and crud thickness is expected to be very low in this location, therefore, this crud pattern appears to be a flow-related phenomenon and is not a concern for fuel performance.

2.2 Once-Burned ATRIUM-10 Visual (Bundles UDJ231 and UDJ223)

Both UDJ231 and UDJ223 are once-burned bundles with the same burnup of 23.2 GWd/MTU. These two bundles were selected for detailed inspection because of their high burnups among the once-burned bundles.

Figure 7 shows Bundle UDJ231 Rod G9 after washing at the 120" location (i.e., about 30" from the bottom of the rod, where the crud is typically the thickest). As can be seen, the fuel surface is smooth. Note that Rod G9 in UDJ231 is a 7.0% Gd rod with an LTP cladding.

Other rods (UO2 rods) individually inspected on these two bundles had normal appearances (see Table 2 for rods inspected).

Similar to the twice-burned fuel, typical dark spots under spacer locations where the spacer springs were in contact with the fuel cladding were observed on the rods. Again, this is normal.

3.0 Conclusions

Based on the visual inspections on six ATRIUM-10 bundles loaded in R16 and R17, it may be concluded that the fuel in Cycle 18 performed satisfactorily. No operability issue is identified for fuel operating in Cycle 19.

The crud pattern observed on Rod K2 in discharge bundle UDH280 was evaluated by the fuel vendor, AREVA, and was concluded that it was not a concern for fuel performance for the rest of the fuel assemblies in core.

One important factor for the continued satisfactory performance since Cycle 17 (oxide thickness data will confirm this once the data is received from AREVA) is water chemistry. CGS has kept FW Zn at a level of ≤ 0.4 ppb and copper ≤ 0.25 ppb in Cycle 18. We should continue to maintain Zn and Cu within the same limits as in Cycle 18.

High Zn in combination with NMCA tends to result in tenacious crud on fuel that may become brittle leading to spallation. Keeping Zn at a reasonably low value of 0.4 ppb is important for good fuel performance.

Without definitive crud analysis (analysis of a crud exposed to HWC for an entire cycle), copper is still an unknown factor in terms of deposition process on fuel surface. Current limit of 0.25 ppb for FW copper should be sufficient from fuel performance standpoint.

Table 1 Bundles Inspected in R18

Bundle ID	Projected Exposure[1] (GWD/T)	Cycle Loaded	Cladding Type	Gd Type	Oxide Thickness	Visual Inspection
UDH010	42.9	17	Gd rods: LBQ[2] UO2 rods: LTP	15GV7.0	Yes	Four sides of bundle
UDH280	41.9	17	Gd rods: 8 LBQ rods, 7 LTP rods[3] UO2 rods: LTP	15GV6.5	Yes	Four sides of bundle[7][8]
UDH056	42.9	17	Gd rods: LBQ[2] UO2 rods: LTP	15GV7.0	No	Four sides of bundle
UDJ231	23.2	18	Gd rods: LTP UO2 rods: LTP	14GV70	Yes	Four sides of bundle
UDJ223	23.2	18	Gd rods: LTP UO2 rods: LTP	14GV70	Yes	Four sides of bundle
UDJ175	23.1	18	Gd rods: LTP UO2 rods: LTP	14GV70	No	Four sides of bundle

1. Projected based on a Cycle length of 645 EFPD.
2. LBQ: Late Beta-Quench
3. Letter, JL Raklios (AREVA) to JD Fisher (EN), FRAEN:02:105, "CGS-1 Bundle Map," December 13, 2002

Table 2 Fuel Rods Inspected in R18

Bundle ID	Cycle Expos.	Rod ID	Clad Type	Rod Type	Oxide Measurement	Visual Inspect	Crud Sample
UDH010	2	G10	LTP	UO2	Yes	Yes	No
		G8	LTP	UO2	Yes	Yes	No
		K3	LBQ	Gd (7.0%)[1]	Yes	Yes	No
UDH280	2	L7	LTP	UO2	Yes	Yes	Yes
		L2	LTP	UO2	Yes	Yes	Yes
		C2	LTP	Gd (6.5%)[1]	Yes	Yes	Yes
UDJ231	1	E10	LTP	UO2	Yes	Yes	Yes
		E8	LTP	UO2	Yes	Yes	Yes
		G9	LTP	Gd (7.0%)[2]	Yes	Yes	Yes
UDJ223	1	E10	LTP	UO2	Yes	Yes	No
		E8	LTP	UO2	Yes	Yes	No
		G9	LTP	Gd (7.0%)[2]	Yes	Yes	No

1. Gd concentration is for axial region from 6" to 132".
2. Gd concentration is for axial regions from 6" to 78" and from 96" to 132".

Figure 1. Fuel Assembly UDH280 Rod C2 (After Washing)

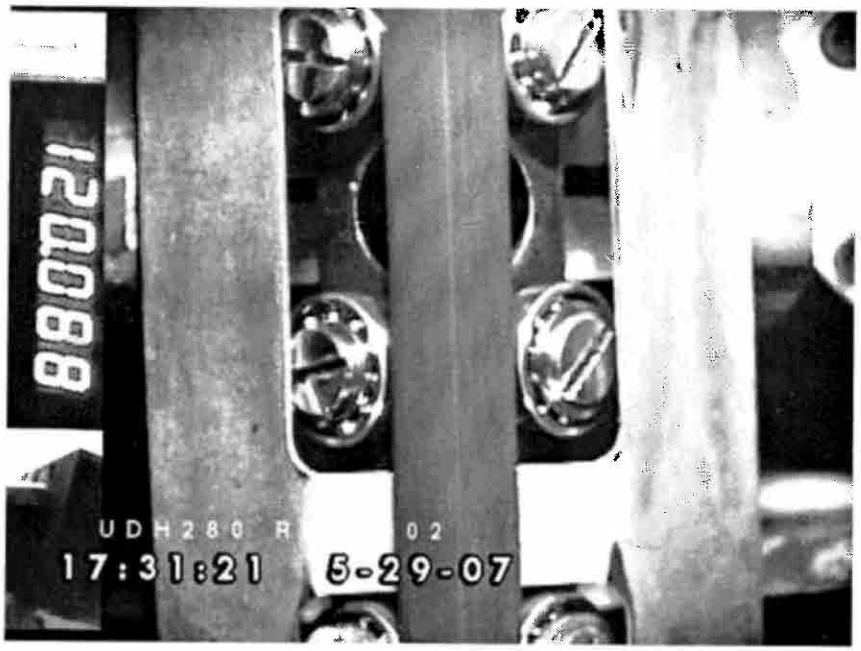


Figure 2. Fuel Assembly UDH280 Rod K3 After Washing (Picture Taken in R17)

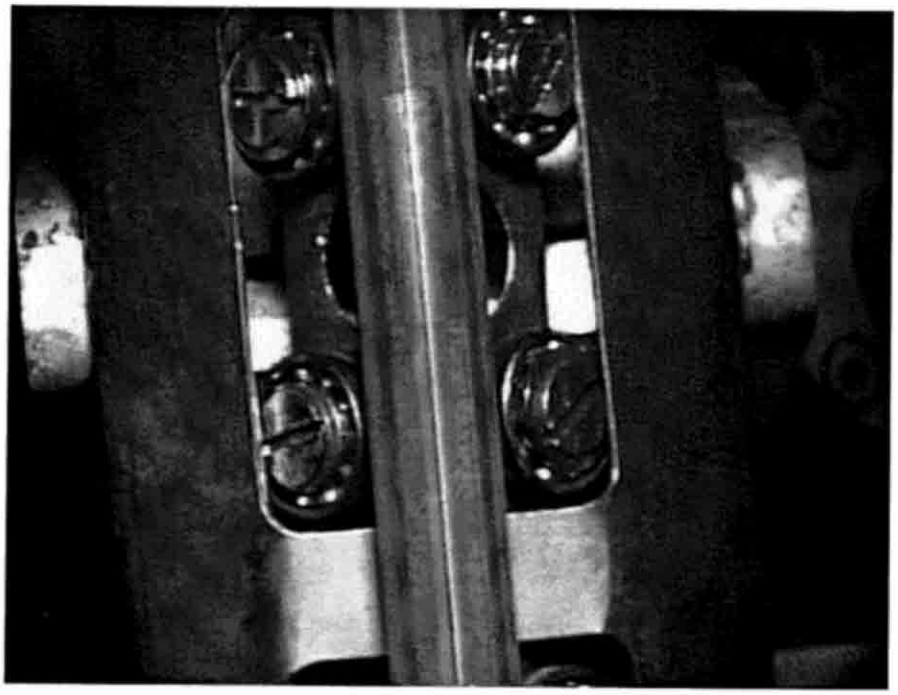


Figure 3 UDH010 Rod K3 Span 1 After Washing

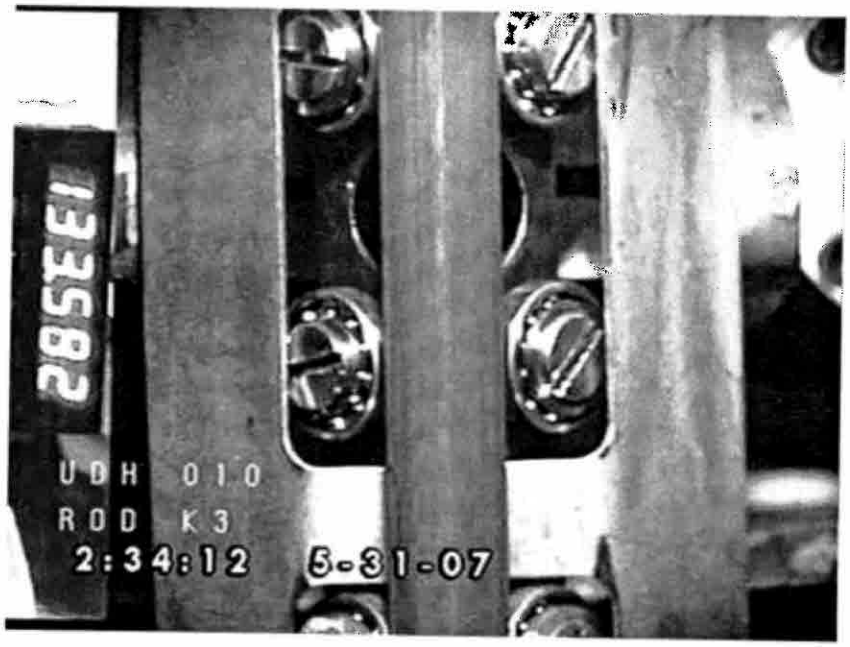


Figure 4 UDH010 Rod K3 Span 1 After Washing (Picture Taken in R17)

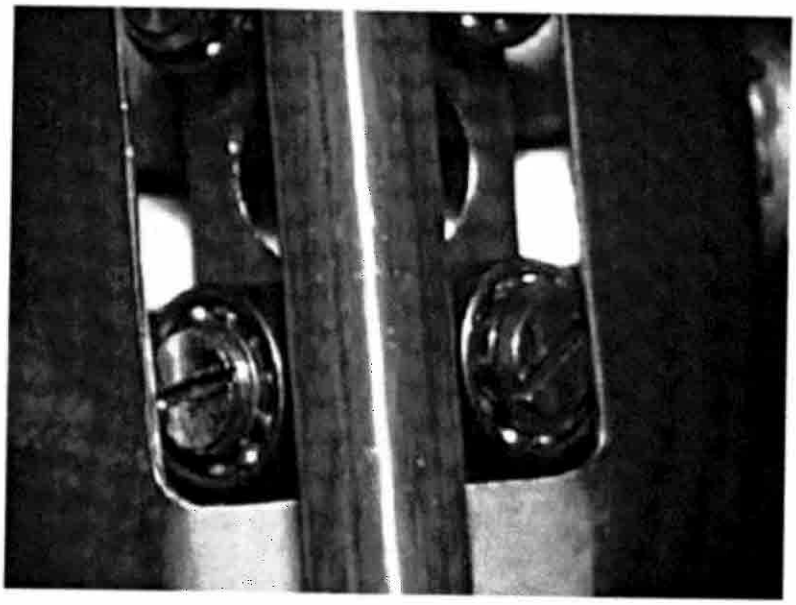


Figure 5 Fuel Assembly UDH280 Rod K2 (Part Length Fuel Rod) Before Brushing

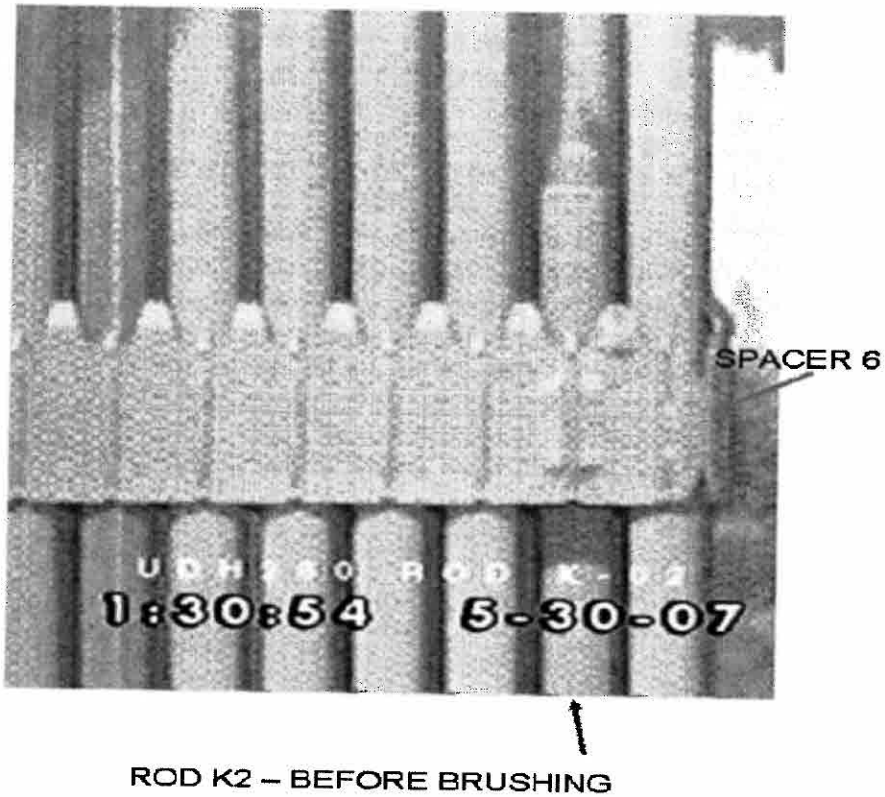


Figure 6 Fuel Assembly UDH280 Rod K2 (Part Length Fuel Rod) After Brushing

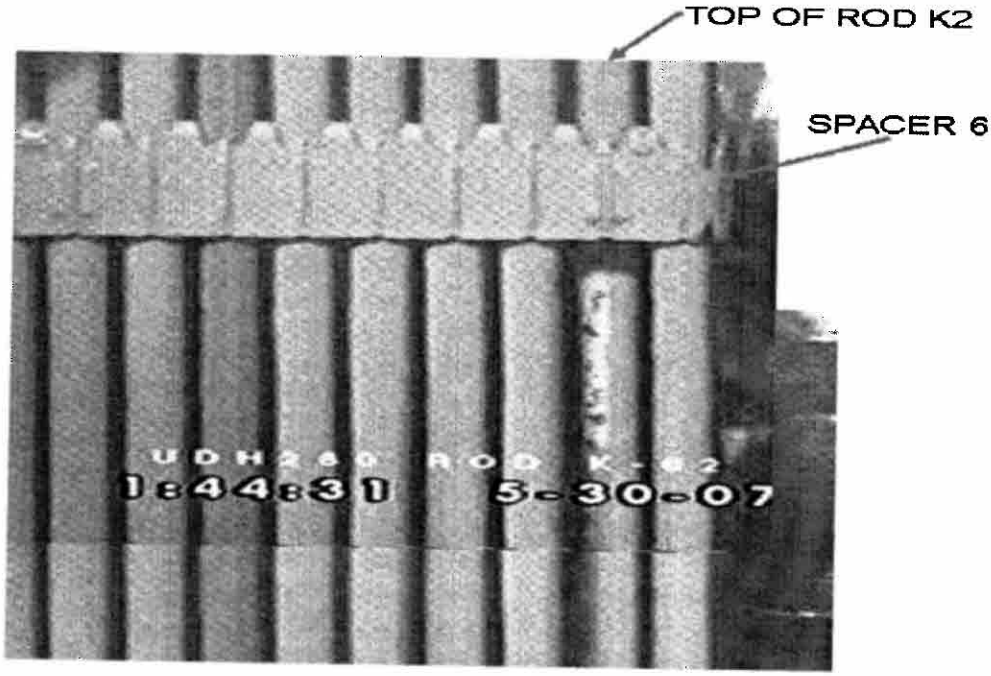


Figure 7 Fuel Assembly UDJ231 Rod G9

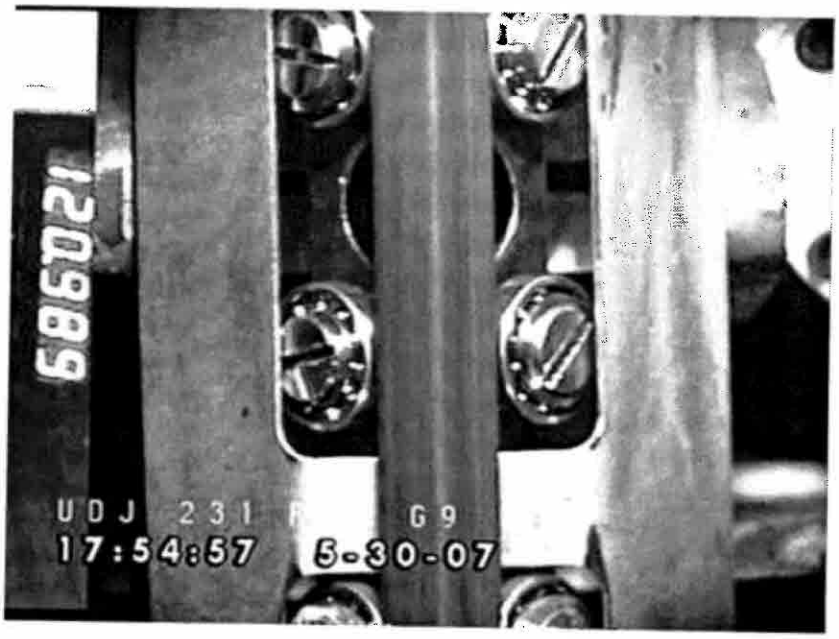
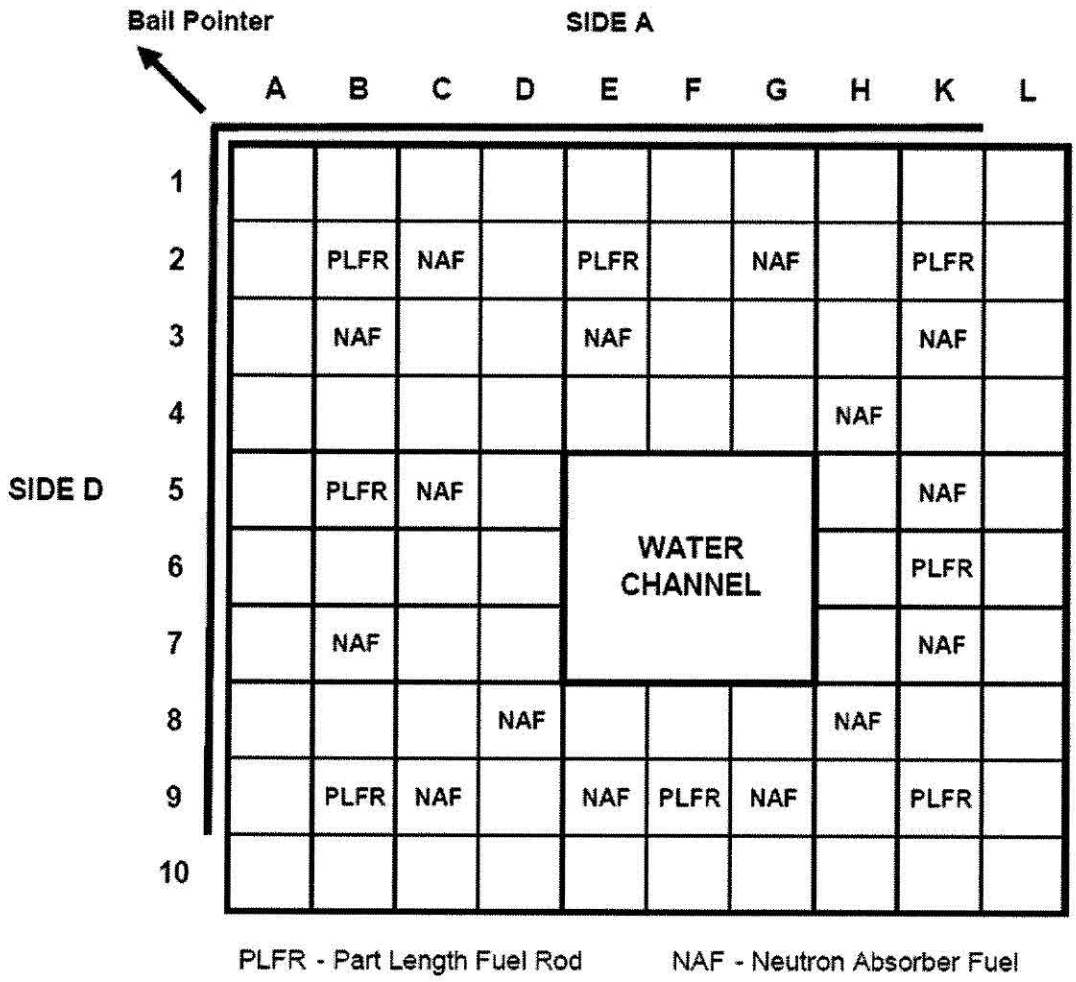


Figure 8 ATRIUM-10 Orientation and Rod Naming Convention



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Tim Sheldon

May 31, 2006

Stephen J. Wright
Administrator and Chief Executive Officer
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

Dear Steve,

Thank you for your letter of May 16, 2006 in which you reaffirmed the importance of BPA and Energy Northwest cooperation on key issues affecting Columbia Generating Station. Clearly both our organizations are best served by working closely and cooperatively with one another. I also appreciated the fact that we were able to discuss some of the relationship issues last week during the NWPPA Annual Meeting at Lake Tahoe. The following paragraph provides a brief synopsis of a process we discussed to address issues of concern to our two organizations.

Issues should be addressed at the appropriate level. For example in the case of the condenser, Steve Oliver and Andy Repacz should meet with Dale Atkinson, Cheryl Whitcomb and/or Scott Oxenford. If resolution is not achieved during those discussions a second meeting with you, Paul Norman and others you may designate would be appropriate. Energy Northwest participants would include the Chairman of the Executive Board, Vic Parrish and others he may designate. Our goal should be to resolve issues as low in our organizations as possible. We are seeking a meeting in the next week or so to discuss issues and begin this process. It's important that these matters are resolved between Energy Northwest and BPA and not as a regional forum.

I believe we both agree that safe operation of a nuclear plant requires decisions based on much more than economic factors alone. Safe and reliable operation of the plant is paramount. To this end Energy Northwest has prepared a "White Paper" outlining issues related to condenser replacement. This document will be provided to BPA and can serve as a resource during the discussions outlined above.

In addition, the Executive Board is currently undertaking a review of documents relating to our working relationships, including the November 14, 2001 "Plan to Strengthen Working Relationship Related to the to the Contract Management of

Columbia Generating Station". This review, when completed, will hopefully lead to an even stronger working relationship between our organizations in the future.

Our commitment to work closely and cooperatively with you and your staff is genuine and remains unchanged. Working together I'm confident we can fully address the needs of all concerned without continuing to blur the line between our organizations' roles and responsibilities. I don't expect a response to this letter, but look forward to our further discussion in the near future.

Sincerely,

Ted

Edward E. Coates, Chairman
Energy Northwest Executive Board

cc:
Executive Board Members
Mr. J.V. Parrish
Mr. Ronald Hatfield
Mr. Paul Rogers

ENERGY NORTHWEST

Sudesh K. Gambhir
Vice President, Technical Services
P.O. Box 968, PE04
Richland, WA 99352-0968
Ph. 509.377.8313 | F. 509.377.2354
sgambhir@energy-northwest.com

January 20, 2009

Mr. Andrew J. Rapacz, M/D 1399
Manager Contract Generating Resources
Bonneville Power Administration
U.S. Department of Energy
c/o Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

EPA
JAN 2 2009
RIC[illegible]D

Dear Mr. Rapacz:

Subject: **ENERGY NORTHWEST AGREEMENT 327447**
MAIN CONDENSER REPLACEMENT MODULES

Energy Northwest intends to execute Contract 327447 with Yuba Heat Transfer in the fixed price amount of $34,660,000 for design, fabrication, and delivery of condenser modules in support of the Main Condenser Replacement Project. Details of the aforementioned transaction are contained in the attached Findings of Fact.

This contract action is subject to the right of the Administrator, Bonneville Power Administration, to disapprove pursuant to the Project Agreement.

Respectfully,

D. Swank For

S.K. Gambhir
Vice President, Technical Services

/kaw

Attachment

FINDINGS OF FACT

COLUMBIA GENERATING STATION RFP 651803

MAIN CONDENSER REPLACEMENT MODULES

SCOPE

This scope of work is for the analysis, design, manufacture, and delivery of replacement condenser modular bundles, and all other requirements in accordance with Procurement Specification 12502. In addition, the Supplier shall coordinate work with Energy Northwest and Energy Northwest's Installation Contractor(s) performing the project management, engineering and installation of the condenser modular bundles at the Columbia Generating Station.

BACKGROUND

The Columbia Generating Station Main Condenser Replacement Project has been broken into two principal segments: (1) the Design, Fabrication, and Delivery to the project site of Replacement Condenser Modules; and (2) Contract(s) for the performance of tasks necessary for the removal of the existing condenser modules and installation of the new replacement condenser modules.

RFP 651803, using the competitive negotiation process was issued on May 23, 2008, requesting proposals for the design, fabrication and delivery of replacement condenser modules. Responsive proposals were received on August 6, 2008, from the following three vendors: Westinghouse (Toshiba), Yuba Heat Transfer, and Thermal Engineering International (TEI). Following vendor discussions and plant site visits with all three proposers, a request for Best and Final Offers was issued on September 29, 2008.

EVALUATIONS

Evaluations of the Submitted proposals were conducted by a Source Evaluation Panel (SEP) with oversight by a Contract Review Board (CRB). The SEP makes its recommendation to the Source Selection Official (SSO) who has the responsibility of making the final decision. See the attached documents for details related to the personnel performing the evaluations, approval by the CRB, submitted prices, and selection criteria with evaluation points used to reach a recommendation for award to the SSO.

- MAIN CONDENSER REPLACEMENT PROJECT PROCUREMENTS -- Appointment of Source Selection Official (SSO) including the Source Evaluation Panel (SEP) and Contract Review Board (CRB).

Demyer, Tanya M.

From: Demyer, Tanya M.
Sent: Wednesday, January 14, 2009 8:31 AM
To: #Distribution A
Cc: Dugan, Cassandra S.; Duncan, Marcia A.; Fleming, Dyana R.; Hammond, Georgia; Vogel, Desiree; Coleman, Douglas W.; Cullen, Gregory V.; Flannagan, John; Frisco Jr, Joseph M.; Jenkins, Bradley Y.; Pagel, Lynne A.; Swank, David A.
Subject: Delegation of Authority - Sudesh Gambhir - January 15-20, 2009

Mr. Sudesh Gambhir, VP, Technical Services will be away from Energy Northwest January 15-20, 2009. Mr. Dave Swank, Major Projects Manager, will act as VP, Technical Services during his absence. Mr. Swank will have the full authority of the position, except that which by policy cannot be delegated.

Should his return be delayed, this delegation will remain in effect until otherwise rescinded.

"Original signed and filed"

FINDINGS OF FACT RFP 651803 (cont)

- Yuba BAFO versus Bid Pricing Comparison
- Condenser Module Proposal Evaluation Criteria for RFP 651803 including assignment of points by the SEP.
- Approval by the CRB to award contract to Yuba (second ranked proposer)

DISCUSSION/NEGOTIATION RECORD

Best and Final Offers (BAFOs) for the replacement condenser modules were received on October 9, 2008, from all three vendors. These BAFOs were evaluated by a Source Evaluation Panel (SEP) using pre-established weighted evaluation criteria. The SEP ranked the (BAFO) proposal provided by TEI as most highly ranked, the proposal from Yuba as second highest, and the proposal from Toshiba as being third. Based on this ranking, the Executive Board was initially requested to approve Executive Board Resolution No. 1584 to authorize award of a contract to TEi

Following approval of Resolution No. 1584, the Energy Northwest Condenser Team entered into extensive discussions with TEi to finalize the contract documents with the intent on making a contract award. During these discussions, serious technical issues were raised concerning the ability of TEi to design and manufacture condenser modules that would meet established technical contract performance requirements.

After it was determined that the technical performance issues raised with TEi could not be resolved in a time frame consistent with the project schedule, Energy Northwest Management approved a request from the Condenser Module SEP to suspend discussions with TEi and to conduct discussions with the second ranked proposer (Yuba). Subsequently, all technical and commercial issues have been resolved and a recommendation by the SEP has been made to award a contract to Yuba. This recommendation has been approved by the CRB. Action Memorandum No.1089 and Executive Board Resolution No. 1593 have been submitted to the Executive Board requesting authorization to award a contract to Yuba in the dollar value of $34,660,000.

FUNDING STATEMENT

This procurement is authorized by Pass Port Contract Requisition No. 651803. Costs will be allocated to Work Order 01125228 – 15.

FINDINGS OF FACT RFP 651803 (cont)

SPECIAL PROVISIONS

The contract is a fixed price contract having liquidated damages for late module delivery and provisions for performance payment adjustments for increased / decreased condenser performance.

RECOMMENDATION

It is recommended that a contract be awarded to Yuba Heat Transfer at the fixed price of $34,660,000 the design, fabrication, and delivery of Replacement Condenser Modules as described in RFP 651803.

APPROVALS

Prepared By: W. G. Edmonds 1-20-2009
W. G. Edmonds, Pr. Contracting Officer — Date

CONCURRENCES:

James L. Hamm For 1-20-2009
B. G. Berglin, Condenser Replacement Project Manager — Date

Pamela Bradley 1/20/09
P. R. Bradley, Assistant General Counsel — Date

D. Swank 1-20-09
D. A. Swank, Manager, Major Projects — Date

G. A. Sponholtz 1-20-09
G. A. Sponholtz, Supervisor, Purchasing & Contracts — Date

L. A. Pagel 1/20/09
L. A. Pagel, Manager, Supply Chain Services — Date

D. Swank For 1-20-09
S. K. Gambhir, VP Technical Services — Date

ENERGY NORTHWEST

INTEROFFICE MEMO

DATE: August 26, 2008

TO: S. K. Gambhir, Vice President, Technical Services

FROM: J. V. Parrish, Chief Executive Officer

SUBJECT: MAIN CONDENSER REPLACEMENT PROJECT PROCUREMENTS

REFERENCE: CONTSEG, Source Evaluation Guidelines, September 2000

On April 28, 2008, a memo was issued assigning you as the Source Selection Official (SSO) and appointing a Source Evaluation Panel and Contract Review Board for the two primary procurements supporting Columbia Generating Station's Main Condenser Replacement Project. The first procurement is for the fabrication and delivery of twelve condenser modular bundles and three intermediate waterboxes; the second procurement is for associated design and installation services. On July 10, 2008, a memorandum was issued revising the composition of the Contract Review Board and Source Evaluation Panel.

As a result of recent staffing changes and the need for backup support, the membership of the Source Evaluation Panel has again changed. Accordingly, the appointment memo is revised to reflect the changes to the Source Evaluation Panel membership as shown below:

<u>Source Evaluation Panel</u>

Chairman:	B.G. Berglin, Condenser Project Manager
Members:	C.L. Grier, Condenser Project Cognizant Engineer
	J.R. Lasalle, Pr. Engineer
	D.R. Senner, Quality Supervisor
	D.A. Swank, Manager Projects
	L.W. Syverson, Quality Auditor II - NDE
	K.A. Whelan/G. Edmonds, Pr. Contracting Officers
	L.J. Woods, Sr. Engineer
Recorder:	Donna Sylvester, Administrative Assistant
Advisors:	R. Bayer, Independent Contractor
	P.R. Bradley, Assistant General Counsel
	J.W. Dabney, Maintenance Component Group Manager
	D.A. Garza, Condenser Project HP Coordinator
	R.S. Korenko, Independent Contractor
	L.D. Morrison, Chemistry Specialist

J.E. Parker, Independent Contractor
A.D. Rains, Staff Attorney
D. Tedeschi, Independent Contractor

Contract Review Board

Chairman: L.A. Pagel, Manager, Supply Chain Services
Members: D.K. Atkinson, VP, Nuclear Generation
J.E. Bekhazi, Planning/Scheduling Outage Manager
A.E. Mouncer, VP Corporate Services/CFO

kaw

YUBA BAFO BID PRICING VERIFICATION FOR RFP 651803 MODULE PROCUREMENT

Description	Yuba $ 01-14-09 Submittal	EN $ BAFO Eval	COMMENTS
12 Modules **(Ti-Clad Tubesheet & 7/8" tubes)** and 3 intermediate waterboxes	**$34,156,000**	**$34,156,000**	Base price includes a re-heat system which is their standard design. No epoxy coating is provided for the intermediate
12 Modules **(Ti-Clad Tubesheet and 1" tubes)** and 3 intermediate waterboxes	**$32,028,000**	**$32,028,000**	
12 Modules **(Ti-Clad Tubesheet & 1 1/8" tubes)** and 3 intermediate waterboxes	**$30,398,000**	**$30,398,000**	
Condensate re-heat system originally specified and provided as an option in BAFO	Included	Included	Integral part of Design and no addl cost for option. Re-heat system replaces area where tubes would be. Addl cost incurred by EN to install partially built reheat system.
3 new inlet and 3 new outlet waterboxes with bolted connections to condenser		**$1,782,000**	Due to design, inlet & outlet waterboxes are the least risk for Yuba design and flow and efficiency are maximized due to the re-heater option being selected
3 new inlet and 3 new outlet waterboxes with welded connections to condenser	**$1,696,000**		**Price deduct provided by Yuba during EN's 1-7-09 to 1-9-09 visit in Allentown, PA.**
Provide temporary supports design and entire permanent design (inside shell) and material	**$950,000**	**$950,000**	

YUBA BAFO BID PRICING VERIFICATION FOR RFP 651803 MODULE PROCUREMENT

Description	Yuba $ 01-14 09 Submittal	EN $ BAFO Eval	COMMENTS
Standard wood boxing of Titanium tubes	**-$100,000**		Specification Rev OA asked for knot free wooden boxes. Yuba offered this price saving unsolicited. Standard boxes have been approved by EN Engineering on 01-
Additional manways and ladder rungs being added to address current safety concerns	Included	**$10,000**	**Yuba included this section as part of the price in their 01-14-09;1:06pm email from Brent Jones to Brian Berglin**
Sparger system injecting leak detection in the intermediate water boxes	Included	**$20,000**	**Yuba included this section in their 01-14-09;1:06pm email from Brent Jones to Brian Berglin**
Provide design of the rail system outside of the condenser bay that would load the condenser modules onto a trailer for shipment.	Not provided	Not provided	Exception agreed to during 01-07-09 meeting. Price is reflective on providing design for everything on the steam side of the condenser.
150 Control tubes & holes in the tubesheets	Included	Included	No exception
Shipping	Included	Included	No exception
Revised 18 gauge & 20 gauge protective tubes per Attachment 9 of 12502 Specification Rev 1Y, 01-10-09.	**$86,000**		**Additional price provided by Yuba during EN's 1-07-09 to 1-09-09 visit in Allentown, PA**
Module Delivery time based on a one month period by July 2010. (Installation Contractor Cost baseline is also 1 month) (Cost not added to total below).	Meets	Meets	BAFO delivery but stretched out 5 months, additional cost incurred by station due to installer bidding on a one month time delivery window.

YUBA BAFO BID PRICING VERIFICATION FOR RFP 651803 MODULE PROCUREMENT

Description	Yuba $ 01-14-09 Submittal	EN $ BAFO Eval	COMMENTS
			01-07-09 to 01-09-09 meeting with Yuba in Allentown, PA they agreed to a 2 month delivery window.
Subtotal 7/8" Tubes	$36,788,000	$36,918,000	
Subtotal 1" Tubes	$34,660,000	$34,790,000	
Subtotal 1 1/8" Tubes	$33,030,000		
Performance Bond 7/8" tubes	Included	Included	No exception
Performance Bond for 1" tubes	Included	Included	No exception
Total 7/8" Tubes	$36,788,000	$36,918,000	Delta between 7/8" &1" tubes. $2,128,000 additional cost. Vacuum gain is .04"hg.
Total 1 1/8" Tubes	$33,030,000	$31,378,000	Least initial cost. Not a feasible option to be considered because of back pressure is 2.48" hg whereas the spec and business case was based on 12 Mwe at 2.41"hg back pressure.
Delta between 7/8" and 1" Titanium Tubes	-$2,128,000	-$2,128,000	

Yellow-used in figuring total selected optioned price

Orange-Revised/new items identified during 01-07-09 EN/Yuba meeting from 01-07-09 to 01-09-09 in Allentown, PA and the 01-14-09;1:06pm email from Brent Jones to Brian Berglin

Blue-delta of 7/8" tubes vs. 1" tubes

Condenser Module Proposal Evaluation Criteria RFP 651803

Evaluation Item	Weight	Points		
		Supplier Name		
		Toshiba	Yuba	TEI
TECHNICAL EVALUATION				
1. Offeror's Response to Procurement Specification/Statement of Work Requirements Completeness	**125**	60	90	110
2. Offeror's Relevant Experience	**125**			
a. Performance-Delivery Record.	15	15	15	15
b. Past Pullout test Historical Performance.	5	2	4	4
c. Demonstrated experience of similar size condenser fabrication and nuclear experience.	10	7	8	8
d. Demonstrated commitment to long term success in condenser replacement	10	10	10	10
e. Past responsiveness to engineering and field modifications	10	5	8	10
f. Previous condenser historical performance record.	75	75	70	70
3. Proposed Team Composition including Qualifications and Experience	**55**			
a. Key personnel	10	2	8	10
b. Proposed subcontractors	5	5	1	5
i. Tube subcontractor's QA and procedural compliance	40	10	30	40
4. Consideration of Offeror's Design and Fabrication Capability and Capacity	**30**			
a. Facilities and manufacturing processes	15	15	8	10
b. QA Program	15	5	10	14
5. Guaranteed performance	**60**			
a. Guaranteed Vacuum performance level (Desired 2.41 max)	60	60	55	60
b. Guaranteed Condensate Temperature Depression (3 degrees F max) *				
6. Consideration of Offeror's Schedule (including subcontractors)	**65**			
a. Fabrication schedule	30	10	20	30
b. Delivery Plan and resource loaded schedule	25	5	18	25
c. Technical and contractual risks	10	5	8	10
7. Offeror's:	**50**			
a. Technical and administrative alignment with Energy Northwest	10	4	8	10
b. Technical interchange of information	10	4	8	10
c. Project ownership	30	10	22	30
8. Overall technical adequacy of the proposal and the likelihood, as judged by Energy Northwest, that the Offeror can meet a required delivery date of July 7th, 2010 given the estimated award date of November 15th, 2008.	**50**	30	38	48
SUB-TOTAL WEIGHT	**560**	339	439	529
COMMERCIAL EVALUATION				
1.0 Acceptance of Terms and Conditions	**100**	60	40	25
2.0 Cost	**250**	205	245	250
SUB-TOTAL WEIGHT:	**350**	265	285	275
TOTAL WEIGHT:	**910**	604	724	804

* Re-heat was provided as an option for BAFO in Addendum 9, Option 2 of the Pricing sheet. The Project team determined from visiting all vendors and evaluating each design and that MWe added from claimed efficiency could not be guaranteed, the value of the requirement in the specification was severely reduced and should be removed.

Source Evaluation Panel Technical evaluation comments:

1 Toshiba:Several exceptions to technical requirements, 25g tubes offered vs. 24g requested, 25g are not used in the US. Shell support design deferred to Westinghouse, material not offered for supports.
Yuba: Did not provide stress analysis for the tube sheet or a design summary as requested. They won't customize their design to fit the Columbia's configuration. An example: Sub-cooling is a standard feature whether you use it or not which could be used to add more tubes if it's not used. Their design increases risk of installation issues without a guarantee of the best back pressure (MWe gain).
TEI: Least amount of exceptions to SOW, design of module is fit around the existing shell design.

2a. All had a good performance delivery record

2b. Toshiba: Information provided was 20 years old and relies on the clad joint with perfect cladding where the weld joint takes the load.
Yuba: A pullout test can be performed at anytime in the shop. They took exception on measuring the wall thickness of 1 out of 50.
TEI: Provided a pullout test procedure but can not perform it right away. They can perform an apparent wall reduction. No exceptions taken by TEI.

2c. Toshiba: Haven't performed a retrofit of a Westinghouse design. Design is flexible to meet Energy Northwest needs.
Yuba: Yuba has designed and provided intermediate water boxes. Floating tube sheet design not flexible to changes
TEI: just performed Big Bend project because they understand the Westinghouse Design. They have not built an intermediate waterbox.

2d. All demonstrated success to a long term commitment of Condenser manufacturing

2e. Toshiba: After field visit and BAFO, the same information was provided even though revised information was requested. Toshiba does not provide a shell analysis and in the BAFO, Westinghouse is providing it. Westinghouse and Toshiba did not demonstrate seamless cooperation.
Yuba: Yuba's computer program for design is conservative and proven. Their staff doesn't appear to be as flexible to changes.
TEI has a solidworks model that can they can respond quickly to changes and demonstrated it during the field visit. They can quickly change drawings.

2f. Toshiba: Fukushima plant started up without any leaks with a new Toshiba Condenser.
Yuba: Lots of other utilities have expressed concern about Yuba's historical performance record. When asked, Yuba had two incidences of performance test they did not meet but fixed them.
TEI: Doesn't have the concern from other utilities, but did have an issue at Ft. Calhoun performance of the condenser.

3a. Toshiba: Westinghouse the middle man to Toshiba. No direct link to Toshiba and their coordination with each other needs improvement
Yuba: Technical team not as strong as TEI. Didn't know who performs stress analysis or mechanical engineering. Organization submitted in BAFO not as strong as TEI's. Project Manager was not dedicated to the Project.
TEI: Very Strong Team submitted with a dedicated Project Manager. Strong technical team and Project Management both at the shop and engineering location

3b. Toshiba: Only used two subcontractors. 1)Tube sheets 2)tubes.
Yuba: Five proposed subcontractors, Yuba did not know which subcontractors they are going to use.
TEI: Only subcontractor is a high quality tube supplier, TEI will manufacture everything else in their own shop.

3bi. Toshiba: They never provided copies of their QA/QC procedures that were requested.

Yuba: Haven't committed to using Valtimet or Ameritie as a tube supplier. Ameritie tubes are a lower cost but their quality program has issues that need to be corrected. The Project Team has both visited the Valtimet and Ameritie factories.
TEI: Has committed to using Valtimet as a tube supplier that has a strong QA program.

4a Toshiba: Quality of work very good and a clean shop. Organization of shop could use some improvement.
Yuba: Very cramped shop, feed water heaters also manufactured. Quality of workmanship better but don't know how their subcontractors perform because they wouldn't commit to who they were so EN could evaluate them.
TEI: Clean shop, lots of room, quality of workmanship could use some improvement.

4b: Toshiba: Their quality personnel could not provide information how they are involved in the manufacturing process. They don't appear to be involved with hold points.
Yuba: Quality Personnel person on site every three weeks. Also visits subcontractors. Quality Personnel didn't appear to work seamlessly with the shop. Checked tubes in the shop during visit, tubes were discovered to be scratched. They did not come back with a strategy to keep the modules clean even though they were asked during the site visit and in the BAFO.
TEI: Lots of improvement since the Columbia's feed water's manufactured. Fulltime person at Sepulpva shop, Corporate QA personnel also located in Joplin, MO close by. Tubes being manufactured in the shop were not found to be very clean during a site visit.

5a. Toshiba: Met requirement but it's based upon using 25 gauge tubes where minimum 24 gauge were specified.
Yuba: 2.36 hg", did not take credit for gains in re-heat, feedback from Technical Consultants is they are conservative in their ratings.
TEI: 2.30 hg", used 23 gauge in their calculation that is conservative. Feedback from Technical Consultants they will not be conservative in their rating.

5b. Re-heat was provided as an option 2 in Addendum 9 of the BAFO pricing sheet. The Project team determined from visiting all three vendors (between the initial proposal and the BAFO) and evaluating each vendor design, there were not guarantees of MWe gained from efficiency. As a result, the value of the requirement in the specification was severely reduced. Pam Bradley, Glen Edmonds, John LaSalle, Craig Grier, Jim Parker, Dave Tedeschi and Brian Berglin all agreed with the removal of the points for BAFO evaluation.

6a. Toshiba: Very high level 5 line schedule provided. Limited information in schedule. No subcontractors showed up on schedule.
Yuba: Detailed fabrication schedule provided. No subcontractors showed up on schedule.
TEI: Detailed fabrication schedule provided. Most detail provided.

6b. Toshiba: Delivery plan will not meet delivery schedule but will deliver in a one month time frame. Proposed delivery time was 3 months after request in BAFO.
Yuba: Will meet specified delivery schedule but over a five month period where one month was specified.
TEI: Will meet specified delivery schedule but over a two month period where one month was specified.

6c. Toshiba: Communication plan through Westinghouse for Toshiba adds risk to miscommunication. Toshiba takes has full ownership of the module it until it hits the unloading dock and turns it over Westinghouse. Not one party involved. Proposal states Westinghouse will be performing the condenser shell analysis which creates a lot of risk because they don't design condensers.
Yuba: More exceptions taken than TEI. Shop personnel concerned with Condensers in the shop. Shop is performing over its capacity. Water boxes need to be modified. Yuba does not subcontract engineering.
TEI: Least exceptions were taken by TEI. Shop is relatively new and has lots of room. Three different condenser were being manufactured at one time. All the machine work is not performed in the shop whereas the shop is a lot cleaner than Yuba's. Joplin performs all the machining and is their Joplin, MO shop keeping the particulate leveling the shop at a very low level.

7a. Toshiba: Had a separate company for Project Management.
Yuba: Did not have a dedicated Project Manager
TEI: Dedicated Project Manager at the same site with the Engineering organization. A second Project Manager was named and will be stationed at the manufactured facility.

7b. Toshiba: Communication barriers through the Westinghouse filter provides added time. A middle person creates a higher potential for technical communication errors.
Yuba: Hesitant to explain how they perform their manufacturing in detail.
TEI: TEI engineering very open to questions and provided answers when requested.

7c Toshiba: Did not commit to who would be on the Project for both Westinghouse and Toshiba.
Yuba: Did not know who exactly will be on the Project
TEI: Project personnel identified for the project which the Project team met on their visit to TEI's facilities. They also presented a Project Plan on how they would perform the Project.

8 Toshiba: Provided flow analysis and a lot of what was requested. Information was not provided for EN Engineering to validate the analysis.
Yuba: Did not provide the analysis requested. Flow analysis was not provided.
TEI: Provide most of what was requested except for Flow analysis. Also provided Engineering for lifting and rail system outside of condenser bay area.

Source Evaluation Panel Commercial Comments:

1. Toshiba: Took no exceptions to Amendment 10 but there are still lots of remaining exceptions that still need to be negotiated.
Yuba: Took minor exceptions to Amendment 10 and in general their exceptions appear to be reasonable.
TEI: Amendment 10 sent out to not take exception to these four terms. They took exceptions to 3 of 4, but the liquidated damages exceptions are difficult for us to clarify and level the field. Exceptions they did take were reasonable and well thought out.

2. Toshiba: $43.6M for 1" tubes.
Yuba: $36.9M for 7/8" tubes - $34.79M for 1" tubes - Delta = $2.13M
TEI:$36.14M for 7/8" tubes - $33.23M for 1" tubes - Delta = $2.91M

ENERGY NORTHWEST

INTEROFFICE MEMO

DATE: January 19, 2009

TO: Lynn Pagel, CRB Chairman

FROM: Brian Berglin, SEP Chairman

For SEP Chairman

SIGNATURE

SUBECT: Closure of Action Items from 01-16-09 Meeting recommending RFP651803 condenser module purchase be awarded to Yuba Heat Transfer

REFERENCE: Control Review Board Meeting held 01-16-09

On 01-16-09, the CRB agreed to proceed forward with the selection of Yuba as the module supplier of choice for RFP 651803 if the following actions are complete. The Project Team committed to complete the actions by 12:00, 01-19-09 or delay the current planned Executive Board Action recommending award of the module contract to Yuba.

1. Provide a timeline with documented verification of the actions from selection of TEI through selection of Yuba
2. Obtain agreement on performance curve of cooling water flow vs. condenser pressure from Yuba and EN Engineering.
3. Obtain payment milestones that are reflective of tangible task and components completed as shown on a Condenser Module Fabrication Schedule.

The following actions have been completed and agreed to by the Project Team.

1. Attached is a timeline record with attachments of the actions from selection of TEI through selection of Yuba. The attachments to the timeline are also attached.
2. On 01-16-09, Dave Cooley, Vice President of Yuba Engineering sent an email and a performance curve of cooling water flow vs. condenser pressure stating he would use the 100% effective tube length at 85% cleanliness factor. The average backpressure increased from 2.36"hg to 2.38"hg for 1" tubes at 550,000 gpm flow. Levi Woods has reviewed and accepted the revised performance curve which will be added as an attachment to the 12502 procurement specification since Yuba's performance incentive is tied to this performance curve.

3. On 01-17-09, Jorge Camacho, President of Yuba sent an email of the revised payment milestones that are reflective of tangible work and components fabricated/delivered which has been reviewed and accepted by myself.

BGB

DISTRIBUTION LIST:

Lynne Pagel

Dale Atkinson

John Behkazi

Al Mouncer

Timeline Associated With Selection of TEI through selection of Yuba Condenser Replacement Project 00608601, RFP 651803

The purpose of this document is to provide the actions taken, and associated documentation, that lead to the selection of TEI as the preferred module vendor. Then, the actions that lead to the decision that TEI would not be able to meet the RFP requirements within the time period required to support R-19 preparation work and R-20 installation. Finally, information is provided on the finalization of discussions with Yuba necessary to return to the EN Board to seek approval for issuance of a contract.

A number of these issues are historical in nature relative to the purpose stated above. Documentation for these actions is readily available, but not included in this document, for Attachments 1 through 7.

5-15-08	RFP, SOW and Evaluation criteria developed (Attachment 1, also see Attachment 8)
5-23-08	RFP and SOW for the modules is issued. The technical requirements are included along with the schedule requirements. The schedule requirements for module design and fabrication are to support R-19 outage work (stiffening of the condenser shell) in support of R-20 installation of the modules. The schedule also supports delivery of the modules in time to support installation of R-20. (Attachment 2)
6-11-08	Pre-Proposal Conference – Modules (Attachment 3)
8-6-08	Proposals are received for the modules in response to the RFQ. There are three bidders and each is deemed to meet the RFQ. (Attachment 4)
9-5-t0-24, 08	Site visits to all three potential vendors are performed by EN personnel. (Attachment 5)
9-29-08	Incorporation of site visit knowledge into the RFP and SOW is completed. The BAFO request is issued to the three bidders. (Attachment 6)
10-9-08	BAFOs received from all three bidders. (Attachment 7)
10-14-08	BAFOs are evaluated by the SEP based on the pre-established evaluation criteria. TEI is ranked the highest in the evaluation. (Attachment 8)
10-15-08	The CRB reviewed and approved the SEP recommendation to proceed forward with TEI based on the documented evaluation. (Attachment 9)
10-16-08	The SEP recommendation to proceed with TEI is accepted by the SSO. (Attachment 10)

Timeline Associated With Selection of TEI through selection of Yuba Condenser Replacement Project 00608601, RFP 651803

10-22-08 Board Resolution is approved by the EN Executive Board to contract with TEI for the modules. (Attachment 11)

10-30-08 A Limited-Notice-To-Proceed is issued to TEI for design work associated with condenser shell stiffening. Issuance of the contract for the modules is dependent on final agreement on terms and conditions and final validation of the TEI answers to questions from the EN/TEI meeting of 11-17-08 to 11-19-08 (due 12-5-08). (Attachment 13)

11-10-08 BPA signs Non-disapproval letter. (Attachment 14)

11-17-to-19-08 The Project Team Met with TEI at their Engineering Office along with our consultant on the condenser project, Burn Engineering. Items associated with the Specification, Statement of Work, General Provisions and Special Provisions were resolved. The meeting resulted in unresolved Engineering Issues related to condensate inundation, condensate sub-cooling, and the modules air removal capabilities. Action items were assigned with the final due date on 12-5-08. (Attachment 12)

12-5-08 Based on the information provided by TEI, EN personnel contacted Grand Gulf and Hope Creek to discuss the TEI (Southwest Engineering) condensers that were installed there. Based on these discussions it was concluded that the designs were different enough from the TEI proposed design for Columbia that a similarity argument on acceptability could not be made. (Attachment 15)

11-19 To 12-19-08 Discussion with TEI to resolve remaining technical issues of condensate inundation, condensate sub-cooling and air removal capability. (Attachment 16)

12-19-08 Held a phone discussion with TEI President Joe Koenig where he indicated that TEI was not going to be able to answer our technical concerns until at the earliest late spring of 2009. There plan is to hire new people to create the technical basis for the design they have proposed since they cannot find these documents. He indicated that he understood that this would not meet our schedule requirements, and could not assure us they would come up with technical justification since the work had not started. (Attachment 17)

12-19-08 Contract discussions with TEI are suspended since the time frame when they might be able to provide answers to our three remaining technical

concerns will not support the EN desire to install the modules in R-20 as stated in the RFP. (Attachment 18)

12-19-08 Initiated discussions with Yuba, as the second highest bidder, for procurement of the condenser modules. (Attachment 19)

12-23-08 EN provided a listing of concerns (spreadsheet) sent to Yuba based on a detailed review of the BAFO by the SEP. (Attachment 20)

1-7 to 1-9-09 Met with Yuba to resolve the remaining concerns from the list transmitted on 12-23-08. Yuba had previously provided their resolutions for some of our concerns. (Attachment 21)

1-12-09 Three major issues remain with Yuba: 1) effective tube length (97%) and the impact on condenser performance calculations; 2) milestone payment schedules and the bases for each; and 3) the need to access liquidated damages associated with Table 4. (Attachment 22)

1-13-09 The drawings in Table 4 will be included in payment milestones. As a result no further action is required associated with liquidated damages for this subject. The language in the Special Provisions has been modified. (Attachment 23)

1-13-09 The condenser module SEP met and concluded that if the two remaining issues could be resolved then the Panel would recommend to the SSO that a contract should be issued to Yuba. (Attachment 24)

1-16-09 Condenser Team met with the CRB and it was determined that this document detailing the timeline for decisions would be created. (minutes to be issued at a later date)

1-16-09 The Condenser Module Decision Logic is attached for information. (Attachment 25)

FINDINGS OF FACT
CONTRACT 326930
ENGINEERING DESIGN SUPPORT SERVICES
MAIN CONDENSER REPLACEMENT PROJECT

BACKGROUND/SCOPE

Engineering services are required to prepare a Plant Design Package for R19 in support of the Main Condenser Replacement Project, currently scheduled for completion in R20. Specifically, services are required to prepare the Plant Design Package for the condenser performance monitoring instrumentation.

Monitoring the performance of the condenser during Cycle 20 will establish a base line of performance parameters for the existing condenser. This data will be compared to the data during Cycle 21 from the new condenser to document improvements, verify manufacturer performance data and establish a baseline for the warranty. This instrumentation will measure the performance for the remaining life of the plant and provide increased equipment reliability which is a station focus in Energy Northwest's strategic objective.

Westinghouse Electric Company LLC (WEC) was selected to perform this work based on previous related experience, i.e., WEC designed and installed the wireless instrumentation for the 6A & 6B Feed Water Heaters. In addition, the Technical Representative has determined that WEC's on-site experience and intimate knowledge of the changes required (gained through their work on the Main Condenser Conceptual Study) makes them the contractor best able to meet the established milestones to design, plan and schedule work for successful completion.

REQUEST FOR PROPOSAL

WEC provided a proposal for these services in the amount of $634,680. WEC has proposed to perform the work under the terms of a previously negotiated Master Services Agreement.

EVALUATION

The WEC proposal has been evaluated and found to be technically acceptable. This work will be awarded to WEC under Contract 326930 which will include the terms of the previously negotiated Master Services Agreement, with minor revisions. The work under this contract will be performed on a Time-and-Materials basis in accordance with rates determined to be fair and reasonable.

FUNDING STATEMENT

Contract Requisition 652910 in the amount of $634,680.00 was approved by S. K. Gambhir, VP Technical Services, on August 5, 2008.

RECOMMENDATION

Based on the foregoing discussion, award of Contract 326930 to Westinghouse Electric Company LLC in the not-to-exceed amount of $634,680 for design engineering services in support of the Main Condenser Replacement Project is recommended, contingent upon BPA non disapproval and the rights of the Participants Review Board.

APPROVALS

Prepared by: _____
K. A. Whelan, Pr. Contracting Officer

Approved:

_____
G. A. Sponholtz, Purchasing/Contracts Supervisor

_____
Legal Services

_____ acting
L. A. Pagel, Manager, Supply Chain Services

_____
Brian G. Berglin, Condenser Replacement Project Manager

_____
A. E. Mouncer, VP, Corp. Services/General Counsel/CFO

INTERNAL DISTRIBUTION:

Mail Drop:

FILE COPY

August 27, 2008

Mr. Andrew J. Rapacz, M/D 1399
Manager Contract Generating Resources
Bonneville Power Administration
U.S. Department of Energy
c/o Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

Dear Mr. Rapacz:

Subject: **ENERGY NORTHWEST AGREEMENT 326930**
MAIN CONDENSER PROJECT DESIGN SUPPORT

Energy Northwest intends to execute Contract 326930 with Westinghouse Electric Company LLC in the not-to-exceed amount of $634,680 for design engineering services in support of the Main Condenser Replacement Project. Details of the aforementioned transaction are contained in the attached Findings of Fact.

This contract action is subject to the right of the Administrator, Bonneville Power Administration, to disapprove pursuant to the Project Agreement.

Respectfully,

S.K. Gambhir
Vice President, Technical Services

/kaw

Attachment

Author: KA Whelan			**For Signature Of:** SK Gambhir		
Section:	C&MS				
For Approval of:	B Berglin				
Approved:					
Date:					

387 R4

ENERGY NORTHWEST

Sudesh K. Gambhir
Vice President, Technical Services
P.O. Box 968, PE04
Richland, WA 99352-0968
Ph. 509.377.8313 | F. 509.377.2354
sgambhir@energy-northwest.com

August 27, 2008

BPA
SEP 08 2008
RICHLAND

Mr. Andrew J. Rapacz, M/D 1399
Manager Contract Generating Resources
Bonneville Power Administration
U.S. Department of Energy
c/o Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

Dear Mr. Rapacz:

Subject: **ENERGY NORTHWEST AGREEMENT 326930**
MAIN CONDENSER PROJECT DESIGN SUPPORT

Energy Northwest intends to execute Contract 326930 with Westinghouse Electric Company LLC in the not-to-exceed amount of $634,680 for design engineering services in support of the Main Condenser Replacement Project. Details of the aforementioned transaction are contained in the attached Findings of Fact.

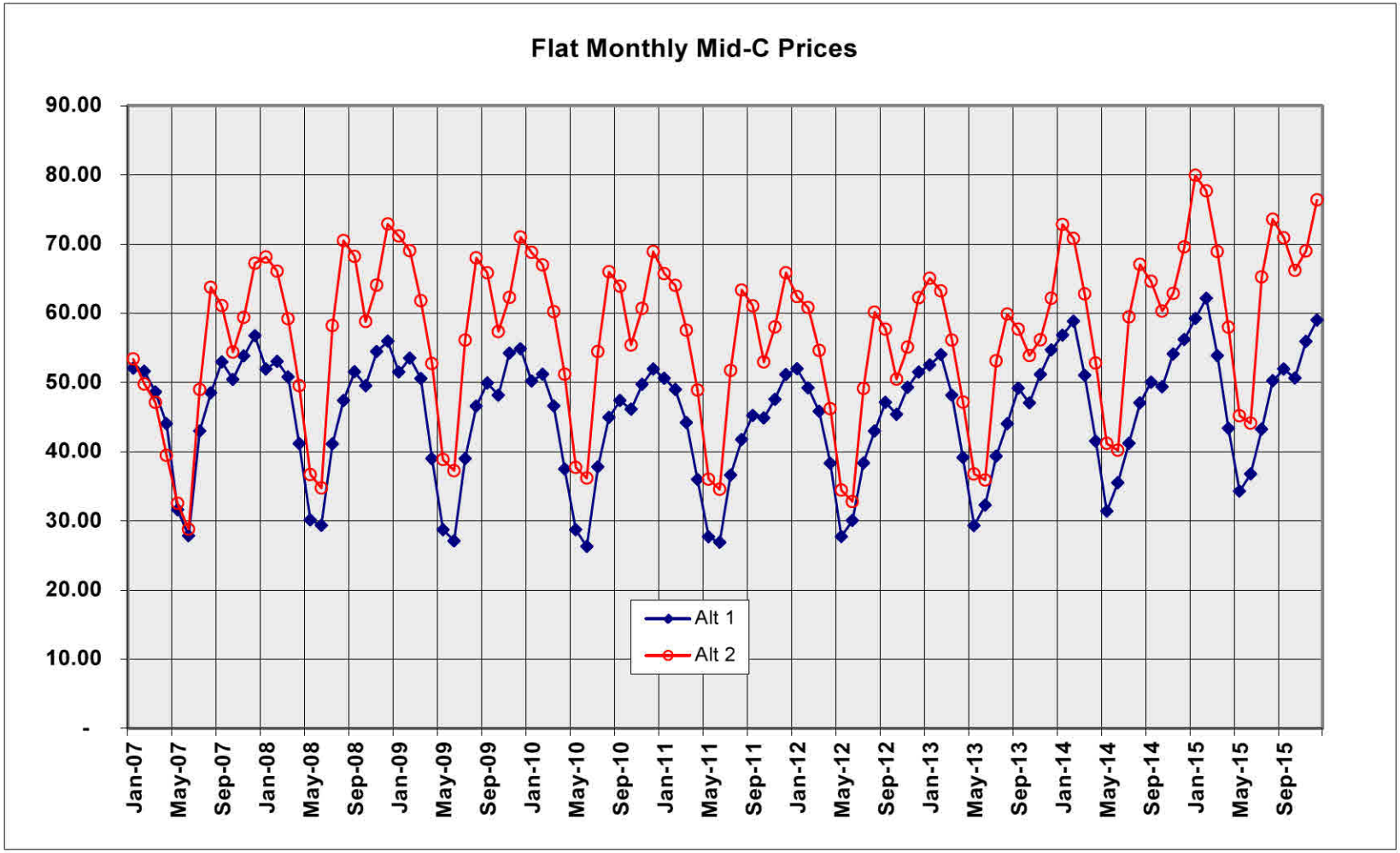
This contract action is subject to the right of the Administrator, Bonneville Power Administration, to disapprove pursuant to the Project Agreement.

Respectfully,

S.K. Gambhir
Vice President, Technical Services

/kaw

Attachment


Flat Monthly Mid-C Prices
90.00
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Sep-15
Alt 1
Alt 2

Prices to use for Condenser Analysis

From Robert Petty
1/10/07

Flat Monthly Mid-C Prices

	Alt 1	Alt 2		Alt 1	Alt 2
Jan-07	52.05	53.36	4 month averages		
Feb-07	51.59	49.75	12 month averages		
Mar-07	48.62	47.12			
Apr-07	44.02	39.44			
May-07	31.58	32.52			
Jun-07	27.81	28.79		38.01	36.97
Jul-07	42.96	48.95			
Aug-07	48.47	63.74			
Sep-07	52.94	61.07			
Oct-07	50.42	54.38			
Nov-07	53.80	59.41			
Dec-07	56.72	67.22		46.75	50.48
Jan-08	51.92	68.13			
Feb-08	53.03	66.08			
Mar-08	50.77	59.19			
Apr-08	41.13	49.50			
May-08	30.12	36.69			
Jun-08	29.34	34.72		37.84	45.02
Jul-08	41.11	58.19			
Aug-08	47.36	70.47			
Sep-08	51.52	68.21			
Oct-08	49.52	58.78			
Nov-08	54.45	64.04			
Dec-08	55.94	72.88		46.35	58.91
Jan-09	51.47	71.16			
Feb-09	53.51	69.02			
Mar-09	50.55	61.81			
Apr-09	38.96	52.72			
May-09	28.70	38.83			
Jun-09	27.08	37.23		36.32	47.65
Jul-09	38.96	56.09			
Aug-09	46.54	67.98			
Sep-09	49.89	65.84			
Oct-09	48.14	57.34			
Nov-09	54.22	62.28			
Dec-09	54.86	70.99		45.24	59.28
Jan-10	50.17	68.77			
Feb-10	51.17	66.99			
Mar-10	46.60	60.23			
Apr-10	37.48	51.17			
May-10	28.69	37.68			
Jun-10	26.27	36.14		34.76	46.31
Jul-10	37.77	54.44			
Aug-10	44.92	65.97			
Sep-10	47.36	63.90			
Oct-10	46.11	55.41			
Nov-10	49.69	60.69			
Dec-10	51.92	68.89		43.18	57.52
Jan-11	50.58	65.73			
Feb-11	48.96	64.00			
Mar-11	44.16	57.54			
Apr-11	35.96	48.88			
May-11	27.68	36.01			

Prices to use for Condenser Analysis

From Robert Petty
1/10/07

Jun-11	26.87	34.52	33.67	44.24
Jul-11	36.60	51.71		
Aug-11	41.72	63.34		
Sep-11	45.20	61.05		
Oct-11	44.86	52.93		
Nov-11	47.54	58.00		
Dec-11	51.13	65.83	41.77	54.96
Jan-12	51.95	62.40		
Feb-12	49.20	60.80		
Mar-12	45.78	54.62		
Apr-12	38.29	46.20		
May-12	27.72	34.40		
Jun-12	30.03	32.78	35.46	42.00
Jul-12	38.35	49.10		
Aug-12	42.97	60.14		
Sep-12	47.11	57.70		
Oct-12	45.38	50.47		
Nov-12	49.29	55.06		
Dec-12	51.49	62.24	43.13	52.16
Jan-13	52.50	65.05		
Feb-13	54.00	63.22		
Mar-13	48.14	56.09		
Apr-13	39.11	47.16		
May-13	29.28	36.77		
Jun-13	32.23	35.89	37.19	43.98
Jul-13	39.32	53.10		
Aug-13	44.00	59.88		
Sep-13	49.14	57.69		
Oct-13	47.01	53.87		
Nov-13	51.15	56.16		
Dec-13	54.68	62.15	45.05	53.92
Jan-14	56.80	72.83		
Feb-14	58.84	70.78		
Mar-14	51.03	62.80		
Apr-14	41.49	52.80		
May-14	31.37	41.16		
Jun-14	35.49	40.18	39.84	49.24
Jul-14	41.19	59.45		
Aug-14	47.01	67.04		
Sep-14	50.03	64.59		
Oct-14	49.34	60.31		
Nov-14	54.11	62.87		
Dec-14	56.20	69.58	47.74	60.37
Jan-15	59.21	79.92		
Feb-15	62.14	77.68		
Mar-15	53.87	68.92		
Apr-15	43.33	57.94		
May-15	34.25	45.18		
Jun-15	36.74	44.10	42.05	54.03
Jul-15	43.22	65.25		
Aug-15	50.22	73.57		
Sep-15	51.92	70.88		
Oct-15	50.61	66.19		
Nov-15	55.92	69.00		
Dec-15	58.99	76.36	50.03	66.25

ENERGY NORTHWEST

INTEROFFICE MEMO

DATE: April 23, 2007

TO: Andy Rapacz, Contract Generating Resources Manager, Bonneville Power Administration, MD1399

FROM: W. Scott Oxenford, Vice President Technical Services, MDPE04

SUBJECT: Response to Bonneville Power Administration questions regarding Main Condenser Upgrade/Replacement

REFERENCE: Letter from Andy Rapacz containing 16 questions, dated March 16, 2007

Our response to the 16 main condenser upgrade/replacement questions is listed below. For ease of reference, the original questions which were contained in the letter dated March 16 are listed in bold prior to each response. If you should have any additional questions or concerns, please contact me at (509) 377-4333.

1. **What is the estimated end-of-life (using the HEI methodology) for the current condenser assuming proper maintenance? Given the 40-year design life of the existing condenser, and the full eddy current testing scheduled during R18, would these results (as well as the R18 fuel inspection results) provide valuable information that either would affirm the current recommendation or indicate that the timing of the condenser replacement should be re-evaluated?**

   End-of-Life Estimate
   The HEI curve was previously provided and is included as Attachment A for your convenience. Predictive uncertainty exists in end of life projection for the Main Condenser. A best effort attempt is provided to define the current condenser limits. No consideration for unit de-rate or reliability has been assumed in the following response.

   - The current condenser is designed to the HEI (Heat Exchanger Institute) standard for surface steam condensers.
   - Since there is no methodology for the end of life, the HEI design guidelines can be applied and used to "box in" and better estimate the end of life, or limits, which may result in increased tube failure.
   - For the end of life curve three HEI design limits were addressed.

- The condenser is designed with 10% excess tube capacity. This is a maximum design limit for tubes plugged because of the significant thermal efficiency loss.
- The actual maximum plug limit is 7.8% based on inlet flow velocities reaching 8 feet/second. This tube material limit will result in significant tube plugging as a result of inlet end erosion.
- Long term tube uniform thinning "boxed area" eventually will result in increased tube deflection and bending, exceeding HEI design limits for ligament design and subsequent mid span collision and tube failure. This is a long term issue rarely experienced since the other mechanisms are predominant. This is caused by uniform loss of material from cooling water and steam side erosion.

- The chart shows the actual plugging data with the current condenser plugged at 3.9%. An assumed linear regression through this data was made to represent the worst case end of life point. This would indicate that the flow velocity limit would be achieved by 2018 or within 11 years. With continued focused maintenance, a life greater than 11 years can be achieved. It is highly unlikely that plant life extension could be achieved with the current condenser.

- Any changes in the following can change the outlook and rapidly shorten the remaining useful life.
  - Increased occurrence of stress corrosion from water chemistry excursions.
  - Increased Dezincification (pitting attack), which is a function of tube cleanliness and scaling
  - Steam impingement thinning influenced by steam trap and balance of plant valve reliability.
  - Gross Foreign Material Exclusion (FME) problems.

Conclusion

As stated in the Main Condenser White Paper and various verbal discussions, the primary driver for condenser replacement is not end-of-life projections. Primary drivers surround sound operational excellence and nuclear safety. Fuel integrity, primary system chemistry control, radiation safety and vessel internal protection are primary financial and safety risks that warrant improved risk management. Industry operating experience in these areas has continued to progress, with standards continually rising. Since the Davis Besse head degradation event, the industry is increasingly intolerant of utility operators that are out of compliance with the BWR Vessel Internals Guidance. Likewise, a new US industry initiative is elimination of fuel failures across the industry by 2010. In both cases, the industry is willing to burden the financial impact to ensure the US Nuclear Reactor Program maintains high margins of safety.

Using our best nuclear judgment, it is inappropriate to delay condenser replacement. Placing it into the Energy Northwest FY08 budget communicates to BPA and the region our intent to move forward promptly. Data from the R-18 Refuel Outage is unlikely to have an impact on our decision, but will certainly be factored into the ongoing decision process.

2. **What are the projected costs for continuing regular refueling outage maintenance on the existing and new condenser?**

   Existing bi-annual condenser maintenance costs:
   Tube cleaning = $385K
   Eddy current testing = $576K (100% testing)
   Dimple plugs = $185K (100%)
   Total cost = $1146K

   NOTE: These costs do not include increased resin, disposal, labor or de-rate costs if a leak occurs during the operating cycle.

   New bi-annual condenser maintenance costs:
   Tube cleaning = $385K (at least first cycle)
   Eddy current testing = $57.6K (10% first cycle – focused on periphery tubes)
   Dimple plugs = $185K (100%)
   Total cost = $627.6K

   The refueling outage maintenance costs for an admiralty brass condenser is well in excess of that for a titanium condenser. Both require a similar type of maintenance, but titanium is much more robust and the extent of the maintenance is expected to be substantially less. A key difference is that titanium is almost a pure metal; pitting, erosion and corrosion are not expected failure modes. Likewise, titanium is more resistant to FME type failures. Therefore the testing for titanium tubing would be started at 10%. The testing could be reduced or eliminated as experience is gained through each additional operating cycle, which would reduce the above costs for the new condenser accordingly.

   Conversely, Admiralty Brass tubing has issues with pitting, cracking, erosion, and is highly susceptible to FME type failures. The above outage costs for the existing condenser are required to extend the mean time between failure (MTBF) for tube leak repairs from 1 to 2 years, decreasing the likelihood of a mid-cycle leak.

3. **What is the estimated life of the new condenser including a comparison with industry experience that supports the estimate? What is the degree of confidence the new condenser will last to the end of plant life in 2043 assuming license extension is implemented?**

   As stated in the Sargent & Lundy Upgrade Scoping Study, the proposed solution is to get through the license extension. Based on our independent review of operating experience, we concur that condenser retube with titanium should support reliable operation through 2043.

   Extensive data on condenser material operating experience is provided in the Main Condenser Upgrade Scoping Study. Many utilities that have upgraded their condenser

have not reached (or approached) what would be considered the end-of-life for their condenser. Current operating experience validates titanium to be a very reliable material for long-term reliable condenser operation. Two specific examples include:

- Songs 2 and 3 have been operating since 1983/4 with titanium tubing with a muntz metal tube sheet. Water and steam erosion and corrosion have not been a problem with the titanium tubes. Currently, there is a problem with the carbon steel stakes and some are planned to be replaced.

- Diablo Canyon has also been operating since the early 1980's with titanium condenser tubes.

  These two plants and others have had very good performance with titanium tubing. These plants each have about 25 years experience and expect the tubing to last through plant life extension.

4. **What is the expected plant energy loss due to condenser driven de-rates during summer months with a new retubed titanium condenser?**

   The expected de-rates for a titanium tube condenser is nearly the same as the current admiralty brass condenser. The de-rates that the plant has experienced during the summer months would generally be the same with titanium. This is based on the estimates contained in the replacement study document and interpolating for current condenser tube plugging of approximately 4.1%. The resultant delta is approximately 5000 MWhrs or 4 full power hours for the titanium tube condenser. An improvement in the cleanliness factor and chemistry control could help in improving the heat rate for the titanium tube condenser. Additionally, replacement of the fill material for the remaining three cooling towers could improve the circulating water cooling efficiency.

5. **Based on industry experience, what is the projected number of tubes that will require plugging for the new condenser through end of plant life assuming license extension is implemented and the corresponding annual energy losses expected due to condenser driven de-rates? What is the likelihood and number of infant mortality tube failures in the new condenser?**

   The industry has had very good experience with titanium tubing. Infant mortality has not been an issue. The tubing is manufactured to high quality standards, virtually eliminating base material defects. Likewise, workmanship is controlled better than the 1970 era condensers. Available industry experience with titanium condensers does not currently indicate the need for extensive tube plugging over the life of the condenser.

   Condenser de-rate information associated with thermal heat rate losses is provided in the above answer. Other condenser de-rates due to leakage will be substantially reduced, if not totally eliminated, following project completion.

6. **What is the ability of the new condenser design to support future power up-rates if up-rates are implemented? What are the other plant equipment upgrades and associated costs that could be implemented to mitigate power de-rates from an up-rated power level condition?**

   As stated in the Sargent & Lundy Condenser Upgrade Scoping Study, the new condenser design does not change the conclusions of the original study for future power up-rates (EPUR up to 3988 MWt). However, power up-rate may exacerbate the need for plant de-rates during summer months. Potential plant equipment upgrades have not been evaluated to date for de-rates after tube replacement, but previous evaluations for current de-rate conditions have identified potential upgrades to the steam jet air ejectors (SJAE) by increasing the capacity of the second stage steam jets or increasing the capacity of the SJAE intercondenser. Based on current de-rate frequency and duration for the existing condenser, these were determined not to be cost effective (first option $150K and second option $500K, with some efficiency loss while at full power). These options as well as others can be evaluated based on future conditions.

7. **Please provide a summary of the number and cycle of occurrence of condenser tube failures at CGS separated into the following causal categories: debris induced, steam impingement, vibration induced, general erosion, SCC and others?**

   Until the last few years, the causes for condenser tube leaks have not been well documented. The total number of tubes plugged through R-17 is 2,017 with the following categorizations as best possible:

   Debris induced (circ water side): 42
   Steam impingement: 222
   Vibration induced: 0
   General erosion / SCC: 1,433
   Other: 320

   Note that "general erosion / SCC" includes tubes plugged during outages based on NDE exam. This population could not be separated between SCC and general erosion based on current information. The "other" grouping includes tubes that scrapers became stuck in, tubes identified as bent, tubes removed for inspections and those identified as "damaged" with no further notation.

8. **Describe the actions taken to address the root cause of FME problems documented in PER 204-0811 and how these actions are expected to prevent recurrence of foreign material caused leaks in the new condenser?**

   Based on the root cause analysis, the foreign material of most concern is tie wraps, especially those that had been used and clipped. These "clipped" tie-wraps frequently become stuck at the #1 tubesheet and then cause fretting damage at that end of the

tube until a pinhole leak develops. The corrective actions implemented included development of enhanced FME zones at the cooling towers and inside the circulating water pump house. Additionally, though not a formal CAP from PER 204-0811, the fill material has been replaced on towers 1A, 2B and 2C. This action resulted in the removal of the tie-wrap materials of concern noted above and replaced them with a stainless steel tie-wrap less susceptible to failure. The replacement of the fill material on the remaining three towers (1B, 1C and 2A) is not currently scheduled and is estimated to cost approximately $2 million per tower. Based on the harsh operating environment of the Cooling Towers and nature of current or future water screens, the best method for eliminating tie-wrap related FME is to rebuild the remaining Cooling Towers.

The effectiveness of implemented corrective actions was measured by the cleanliness of the waterboxes upon initial entry during tube plugging evolutions and outages. There was evidence of biological materials and some cooling tower parts, but no tie-wraps or tie wire pieces were found upon initial entry and inspection of the tubesheets. Further cleaning of the circulating water system is scheduled in R-18.

Finally, the source of FME can be substantially reduced, but as with any raw water system, cannot be totally eliminated. Expectations for the new condenser are that these actions combined with the increased toughness of the new titanium tube material will substantially decrease the potential for tube leaks due to foreign material intrusion.

9. **Please provide a summary of the number and cycle of occurrence of fuel failures at CGS separated into the following causal categories: foreign material induced fuel fretting, copper interaction with fuel cladding, condenser leakage (Feedwater contaminants) and others.**

Columbia Generating Station (CGS) has experienced no fuel defects in the current or previous 2 operating cycles. CGS did have one minor fuel failure in cycle 15 (year 2000) due to foreign material fretting. Prior to cycle 15, fuel failures at CGS were identified in cycle 5 (year 1989) due to (1) crud induced localized corrosion (CILC) when the industry was in a discovery phase on the copper related mechanism, (2) fuel fretting and (3) an unknown cause.

CGS experienced fuel corrosion during cycle 15 due to a condenser tube leak resulting in a reactor water chemistry excursion event. CGS formed a multi-disciplined Fuel Corrosion Task Force with internal and external experts to evaluate the fuel corrosion. CGS did not experience any fuel failures from the event. Substantial organizational concern existed that fuel damage could occur, leading to an extended outage for extensive fuel reconstitution or replacement. Fortunately, fuel failure did not result. Much of our current source term leading to high dose rates can be directly correlated to the elimination of zinc injection to prevent further corrosion of the fuel for the subsequent operating cycle to minimize the potential of fuel damage.

In summary:

Debris fretting : 2 failures; 1 in cycle 5, 1 in cycle 15
Copper interaction with fuel cladding: 2 failures in cycle 5
Condenser leakage: 0 failures, 1 or more "substantial near misses" in cycle 15
Other: 1 in cycle 15 of unknown cause

Additionally, CGS had fuel failures in cycle 3 and 4 that were never identified. These could have been similar to the cycle 5 failures. It appears that one failure was removed at End of Cycle 3. During cycle 4, operation 1-3 failures were thought to be present, but never identified. It appears that one or more of these failures were removed at End of Cycle 4, but some remained based on indications of failed fuel at beginning of Cycle 5.

10. **Please provide the projected number of fuel failures between now and end-of-life (as estimated in question 1) of the current condenser separated into the following categories: foreign material induced fuel fretting, copper interaction with fuel cladding, condenser leakage (Feedwater contaminants) and others. Also, provide the projected number of fuel failures expected during the lifetime of the new condenser separated into the same categories.**

There are 3 primary fission product barriers to radiation reaching the public;
1. Primary Containment
2. Secondary Containment
3. Fuel Cladding.

The US industry has historically protected Primary and Secondary Containment barriers extensively, while tolerating some level of fuel failures at many units. Over the last several years, this view has changed and the Chief Nuclear Officers established a US industry goal of 'ZERO Fuel Failures by 2010'. The level of performance previously tolerated is no longer acceptable.

It is our responsibility to take the necessary precautions and actions to prevent future fuel failures. Based on this premise, we do not expect any future fuel failures since we will act on known challenges. By performing a prediction of future fuel failures, we could be perpetuating an operating philosophy that preventable fuel failures might be tolerated.

Finally, predictive tools to answer the question do not exist, so we will not project fuel failure rates. The best investment that CGS can make to minimize future potential fuel failures is modifying the condenser to eliminate impurities reaching the primary system and minimizing copper.

11. **What are the estimated levels of Feedwater copper before and after condenser tube material replacement? Will the copper levels after tube replacement meet all industry guidelines?**

Copper before: 0.20 ppb (min), 0.35 ppb (max)
Copper after: 0.02 ppb < 0.05 ppb (industry standard)

The above projection has been confirmed through stations with Muntz metal tubesheets

12. **What is the estimated dose reduction relative to collective radiation exposure (CRE) performance indicator separated into the following categories: dose reduction due to condenser tube material replacement, dose reduction associated with chemical decon during refueling outages, dose reduction associated with the cobalt reduction effort and dose reduction associated with fewer tube leak repairs? What is the estimated CRE performance indicator after R19 and after R20 if the condenser is not replaced and the cobalt reduction efforts proceed and chemical decons are conducted as part of future refueling outages?**

Dose reduction can be identified for an activity, like chemical decontamination. The complexity comes about from the rate of re-deposition based on other variables. To be successful in achieving industry accepted source term levels, excellent primary water chemistry, fuel performance, cobalt reduction, and chemical decontamination must all work together. To respond to your question, the following data is provided with the caveat that use of any number without putting it into a very dynamic context could cause one to reach inappropriate conclusions.

- Dose reduction due to condenser tube material replacement is not a readily quantifiable value. It is expected that plant dose rates would increase more rapidly with copper present. How much is unknown since plants having had this experience have quickly corrected the copper input.

- Dose reduction associated with chemical decon during refueling outages:
  - R-18, 64Rem
  - R-19, 50Rem

- Dose reduction associated with cobalt reduction effort is unknown. This prevents future build-up and plants that have done this are showing steady dose rates from cycle to cycle.

- Dose reduction associated with fewer tube leak repairs on-line is 6-8Rem/year

- Estimated CRE performance indicator after R-19 and R-20 if the condenser is not replaced, the cobalt reduction efforts proceed, and chemical decontaminations are conducted can expect 3rd or 4th quartile for the next 4 years (160-180 Rem).

13. **Describe EN's enhanced ability to detect and repair condenser tube leaks and confirm whether this is included in the cost benefit analysis business case?**

The ability to detect and repair condenser tube leaks was not included in the cost benefit analysis. The cost benefit analysis was based on increased reliability of the condenser, not enhanced detection of leaks.

BPA staff is aware of our capabilities in this area, so a written description of our capabilities has not been provided.

14. **What is the total cost estimate to replace the condenser with the option EN has chosen excluding the cost of replacement power? Based on the past history of cost increases in major plant projects including ISFSI, HWC, DEH and FWH replacement, provide the degree of confidence associated with the cost estimate.**

Cost break down for condenser retubing with titanium tubes:
Material costs: $11,000,000
Contractor costs: $10,120,000
EN costs: $ 3,500,000
Decon costs: $ 3,500,000
Total: **$28,120,000**

These costs did not include a turnkey contractor or escalation.

Factors that can adversely impact the estimate include labor availability, material demand, cost for schedule reduction initiatives, and costs associated with a 2-outage schedule. Taking these into account, the costs could increase as much as 25%. Over the coming year, additional schedule, procurement, and planning activities will increase the accuracy of the estimates and our FY09 budget will be much more precise.

15. **Please provide a copy of the of the cost benefit analysis business case for the condenser replacement including a summary explaining the assumptions that were used and verified in the analysis.**

Refer to Attachment B.

16. **Given the net present value of negative $65 million for the chosen replacement option, please describe the offsetting factors (i.e., regulatory commitments, INPO recommendations, etc.) that make this a viable project from a cost benefit perspective. Are there any other alternative options including condenser replacement deferral to end-of-life estimated in question 1 that result in a less negative, zero or positive net present value?**

The viability of this project is provided in the Main Condenser White Paper, dated June 2006.

Per the cost benefit analysis business case provided (see response to question 15 above) the selected option has the least negative present value. The business case was performed in a manner to compare alternatives. Different assumptions and evaluation methods would be required if we were to evaluate an option of such a lengthy deferral. For example, one extended outage and fuel replacement campaign would provide an immediate payback. We do not believe it is prudent to evaluate a deferral of this length, but did include a 'Base Case' (6 year deferral) evaluation at the request of BPA.

The option of deferring to end-of-life was not included in the original analysis as it would increase the probability for fuel failure, vessel internals degradation, and adverse dose, with significant consequences to the station, the industry, and the region.

dc

DISTRIBUTION LIST:

Mr. Steve Oliver, Bonneville Power Administration

Mr. Sid Morrison, Energy Northwest Executive Board

Mr. JV Parrish, Energy Northwest, MD1023

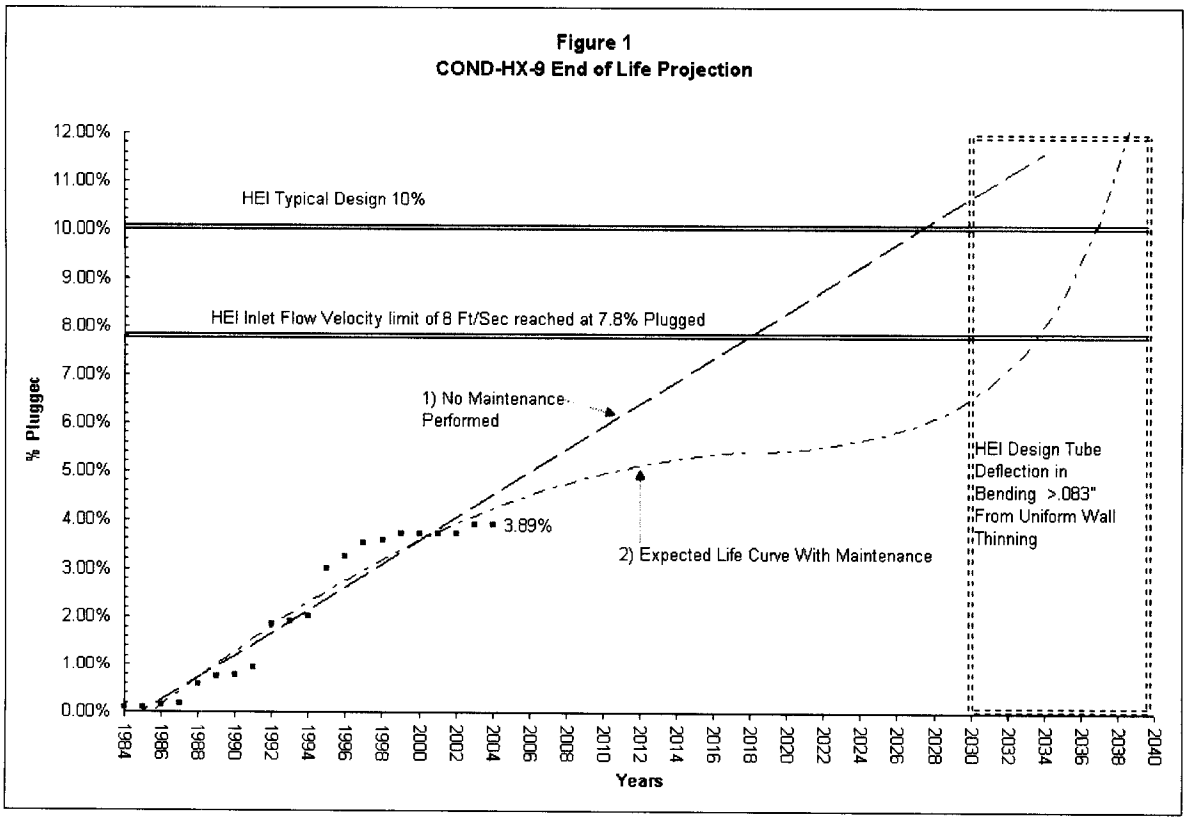
Mr. Dale Atkinson, Energy Northwest, MDPE08

Mr. Abdy Khanpour, Energy Northwest, MDPE23

Attachment A

There has been a lot of speculation regarding the end of life for the condenser and the figure below is an attempt to frame the perspective with a projection of the life curve. The HEI design criteria is used to help define the limits based on increased flow rates and uniform thinning, resulting in exceeding the design tube deflection towards the end of life.

The chart below is a best guess of the end of life projection for the condenser tubes. This chart displays the actual percent of tubes plugged and a regression through the data, with limiting condition being flow rate and uniform thinning at the tail end of the life cycle. No consideration for loss or unit de-rate has been assumed. The 7.8% plugged should be considered to be the limit for useful life. The range for the condenser end of life should be considered to be between 2018 worst case and 2033 best case. Plant operation chemistry and maintenance determine the end point. The emergence of additional SCC or gross steam damage can easily change this outlook and eat up remaining margin rapidly.



Attachment B
(See Next Page)

Energy Northwest

Date: 1/29/07

To: Executive Authorization Committee

From: Joe Frisco Project Manager

Subject: Project Number 00608601 Conceptual Study to Replace Main Condenser Tubing

Executive Summary

The purpose of this business case is to evaluate the Sargent and Lundy Main Condenser Upgrade Scoping Study and prepare cost analysis for replacing the main condenser tubing. The study documents a condition assessment and tube replacement options for improving the reliability of the main condenser at the Columbia Generating Station. The report also discusses the best method to reduce the copper source in the reactor water. The replacement options are evaluated with respect to material and installation costs, maintenance costs, estimated outage durations, thermal performance, ALARA avoidance costs, and lost power revenue.

PHC Project Ranking	**16**
Project Type	**Capital**

Summary Cost Estimate

	FY07 $K					
	Base Case	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Current Estimated Capital Costs	$ 30,586	$ 54,512	$ 25,897	$ 30,586	$ 63,493	$ 80,933
PHC/EAC Approval						

Options Considered

Base Case - Delay condenser retube approximately 6 years to FY13 and then use Alternative 3
Option 1 - Retube with copper in FY09 and install deep-bed deminerlizers in FY11
Option 2 - Retube with stainless steel (Sea-Cure) in FY09
Option 3 - Retube with titanium in FY09
Option 4 - Retube with modular stainless steel bundles (Sea-Cure) in FY11
Option 5 - Retube with modular titanium bundles in FY11
Option 6 - Retube over 2 outages with titanium - not considered viable due to 1) outage penalties would double, 2) thermal expansion differences from different materials

Recommended Option

Option 3 - Retube with titanium in FY09

Background

The goal of the study is to find a cost effective replacement for the main condenser tubing. Sargent and Lundy has issued the final report, titled "Main Condenser Upgrade Scoping Study" dated Dec. 14, 2006. The study documents a condition assessment and tube replacement options for improving the reliability of the main condenser at the Columbia Generating Station. The report also discusses the best method to reduce the copper source in the reactor water.

Columbia has a history of small tube leaks that have been difficult to find and tube failures that have caused seven plant shutdowns and down powers between 2003 and 2006. The main condenser in leakage has been identified as the major factor which challenges reactor water chemistry. Main condenser circulating water in leakage is currently one of the top ten equipment material condition issues at Columbia.

Throughout the plant life and especially in the last four years the leaks have been caused by foreign material that has been introduced in to the circulating water system. The plant has committed to improving the FME controls and performing a 100% eddy current inspection to improve the reliability of the condenser.

The condenser contributes copper in the feed water in the form of soluble copper and insoluble copper. The combination of HWC and Noble Chem appear to cause the copper to plate out on the reactor internal surfaces. The risk of copper plating out on the fuel is largely unknown and could be detrimental. The presence of significant amounts of copper constitutes a substantial increase in the risk of fuel failure should a fuel corrosion event occur.

Strategic Fit and Risk Discussion

Columbia Generating Station cannot maintain feed water copper levels low enough to meet industry guidelines (less than 0.1 ppb). Industry guidelines continue to lower the recommended copper levels. Feed water copper levels have been a documented contributor to fuel rod corrosion and failures.

Columbia Generating station has an admiralty brass condenser and a condensate filter demineralizer system. The combination of these two systems only allows the feed water copper level to be controlled at less than 0.35 ppb.

A do nothing position will eventually result in several of the aging factors related to the condenser causing a limitation on operation at rated power. Fretting at the tube supports, water and steam erosion of the tubing wall, stress corrosion cracking, pitting and circ water velocity will increase as plugging increases which will all cause a sharp increase in the failure rate. This will be considered the end of the condenser useful life.

The addition of the deep bed demineralizer was not estimated with the same confidence factor as the other costs. There is considerable risk that the estimated cost is low. If the deep bed option was the recommended option, a more accurate estimate should be generated.

Both stainless and titanium tubing in a Muntz Metal tube sheet require an impressed current cathodic protection system. Both materials are susceptible to hydrogen embrittlement if an over voltage occurs over several days. There fore the design, maintenance and operation of the cathodic protect system is critical.

The condenser contributes copper in the feed water in the form of soluble copper and insoluble copper. The combination of HWC and Noble Chem appear to cause the copper to plate out on the reactor internal surfaces. The risk of copper plating out on the fuel is largely unknown and could be detrimental. The presence of significant amounts of copper constitutes a substantial increase in the risk of fuel failure should a fuel corrosion event occur. Fuel corrosion has been responsible for fuel failures at other plants in the late 1970's and 1980's. Recent fuel failures have been attributed to cladding corrosion from heavy crud corrosion. At most stations, the corrosion failure mechanism was mitigated by improvement of the nodular corrosion resistance of the fuel cladding, and in many of the cases by removal of the copper source (by replacement of brass condenser tubing or with improved condensate treatment technologies. Following Cycle 15 Columbia experienced a case of enhanced cladding nodular corrosion, but with out cladding failure. The industry and INPO have urged the plants to meet the water chemistry goals from BWRVIP-130. Vermont Yankee and Columbia are the last two US nuclear plants with out a deep bed demineralizer that have copper condenser tubing. The Probability that copper in the feed water, at present concentrations will result in fuel failure is unknown. For the purpose of this evaluation the probability is assumed to be 5% per year and would affect the third cycle fuel. This risk has a severe outcome if it does result in fuel failure. Experience from other plants that have fuel failures would result in the following costs to Columbia; the failed fuel would be examined to perform crud analysis/corrosion thickness analysis and root cause for about $4,000,000, and then an emergency procurement of 100 fuel bundles @$250,000 each. The plant would be in outage for approximately 2 months and the reactor would be defueled to remove the

damaged fuel and then refueled with the new fuel. The direct costs for the outage would be conservatively $4,000,000. The estimated dose for defueling-refueling is 17 Man R. Long term affects would last for several years in the form of higher dose and contamination.

The presence of copper in the reactor water negates the benefits of zinc injection for dose reduction. The shutdown dose rates for Columbia are the highest in the BWR fleet and are showing an increasing trend. The dose estimate increase is approximately 50 man R each outage. A recirc decon ($4,367K)(15manR) is required prior to an outage and one after the copper is removed from the condenser.

Tube vibration assessment by Sargent and Lundy, suggests that the spacing between tube supports is adequate to prevent flow induced vibration, FIV. However a more conservative method suggested staking was required. FIV is minimized through adequate support spacing. A refined tube vibration assessment is recommended if retubing with titanium is selected. The refined assessment may require staking for titanium tubes. The titanium retubing cost comparison does include tube staking since the Sargent and Lundy assessment indicated staking was required by the conservative HEI method. The added cost for staking was $550,000.

If a shell hydro test of the condenser is required to assure the tube to tube sheet joints are leak free, a water management plan needs to be developed. Sufficient water can be made in three days and cleanup time for water disposal is 10 days. Clean up rate is 60,000 gallons/day. This evaluation assumes a successful water management plan is implemented to eliminate the schedule delay of making water and cleanup for disposal. A condenser shell hydro is only required for retubing. An alternate test is to perform a vacuum pull and use sonic means to check for tube leaks.

Risk if not Approved

The material condition of the condenser will degrade to the end of useful life before the licensed life of the plant or the planned license renewal to 2043. A major over haul could be required in about ten years.

The combination of HWC and Noble Chem appear to cause the copper to plate out on the reactor internal surfaces. The copper may increase the risk for fuel failures. The probability of the risk is small but the consequences are large. The copper also causes higher shutdown drywell dose rates. The dose is about 50 ManR per outage and a Recirc decon ($4,367K)(15 ManR) is required prior to an outage and one after the copper source is removed from the condenser.

COST BENEFIT ANALYSIS

Key Assumptions/Qualifications

Note: All alternatives will result in condenser retube

Discount Rate		6.5%
Escalation		3.0%
Man-rem exposure costs $K/man-rem	$	25
FY09 Outage w/o Condenser (days)		35

		FY07 $K					
Other Cost Impacts Assumptions		**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Radiation							
Radiation Impacts Retubing (man-rems)		12	12	12	12	60	60
Cost per Man-rem (FY07$K)		$ 25	$ 25	$ 25	$ 25	$ 25	$ 25
Total Radiation Impacts (FY07$K)		$ 300	$ 300	$ 300	$ 300	$ 1,500	$ 1,500
Installation Outage Impacts							
Incremental Outage Impact (Days)		33	25	33	33	85	85
Lost MWH from Outage Impact	1107	876,744	664,200	876,744	876,744	2,258,280	2,258,280
Annual Derate/Increase							
Lost MWH from Summer Derate		17,133	-	27,818	17,133	-	-
Increased Generation (MWH)						91,542	91,542
Additional Annual Inspection Costs							
Per Outage (FY07$K)		$ -	$ -	$ -	$ -	$ 220	$ 200
Chemical Decon		$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367
Radiation Impacts from Decon (man-rems)		15	15	15	15	15	15
Radiation Benefits for Copper Removal							
Man-rems Saved		50	50	50	50	50	50
Value of Man-rems saved (FY07 $K)		$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250
Fuel Failure Risk from copper							
Probability of failure Annually							
prior to retube post FY09		0.05	0.05			0.05	0.05
Cost of a failure							
Direct Cost (FY07$K)		$ 4,000	$ 4,000			$ 4,000	$ 4,000
Fuel Purchase (FY07$K)		$ 25,000	$ 25,000			$ 25,000	$ 25,000
Root Cause Analysis (FY07$K)		$ 4,000	$ 4,000			$ 4,000	$ 4,000
Radiation Costs of a failure (FY07$K)		$ 425	$ 425			$ 425	$ 425
Total Fuel Failure Costs (FY07$K)		$ 33,425	$ 33,425			$ 33,425	$ 33,425
Annualized Cost for Fuel Failure Risk (FY07$K)		$ 1,671	$ 1,671			$ 1,671	$ 1,671
Downpowers for Condenser Problems Post FY09							
Direct Costs (FY07$K)		$ 605				$ 605	$ 605
Annual Average Lost Generatic	40	$ 2,358	Based upon 6 in the last 3 years due to			$ 2,358	$ 2,358
Total Downpowers Loss and Cost (FY07$K)		$ 2,963	condenser tube leaks			$ 2,963	$ 2,963

Results - Present Value Details - Magnitude and Sensitivity of Input Assumptions

	FY07 $M NPV					
Impact/Description	**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Installation Costs	$ (24.9)	$ (49.0)	$ (24.0)	$ (28.4)	$ (55.3)	$ (70.5)
Installation Outage Impacts/ Incl Dose	$ (24.6)	$ (24.9)	$ (32.7)	$ (32.7)	$ (85.0)	$ (85.0)
Chem Decon (incl dose)	$ (11.7)	$ (8.0)	$ (8.0)	$ (8.0)	$ (11.7)	$ (11.7)
Fuel Failure Risk	$ (5.8)	$ (3.0)	$ -	$ -	$ (3.0)	$ (3.0)
Projected Downpowers for Tube Leaks	$ (10.2)	$ -	$ -	$ -	$ (5.3)	$ (5.3)
Reduced Dose	$ 17.5	$ 19.4	$ 19.4	$ 19.4	$ 17.5	$ 17.5
(Derate)/ Increased Generation	$ (13.6)	$ -	$ (25.6)	$ (15.8)	$ 69.6	$ 69.6
Added ongoing Inspection Costs for Modular	$ -	$ -	$ -	$ -	$ (1.8)	$ (1.7)
Total	**$ (73.2)**	**$ (65.4)**	**$ (71.0)**	**$ (65.5)**	**$ (74.9)**	**$ (90.0)**

ESTIMATED COSTS BREAKDOWN

		FY07 $K					
		Base Case	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Capital Costs by Work							
Retube Condenser/Includes Disposal Costs		$ 28,061	$ 25,011	$ 23,759	$ 28,061	$ 58,250	$ 74,250
Deep Bed Demin		$ -	$ 25,000	$ -	$ -	$ -	$ -
Sales and Use Tax	9%	$ 2,525	$ 4,501	$ 2,138	$ 2,525	$ 5,243	$ 6,683
Total Capital Costs		$ 30,586	$ 54,512	$ 25,897	$ 30,586	$ 63,493	$ 80,933

PHC/EAC Approval

Executive Summary

PHC Project Ranking	**16**
Project Type	**Capital**

Summary Cost Estimate

	FY07 $K					
	Base Case	Option 1	Option 2	Option 3	Option 4	Option 5
Current Estimated Capital Costs	$ 27,262	$ 54,512	$ 25,897	$ 30,586	$ 63,493	$ 80,933
PHC/EAC Approval						

Options Considered

Base Case - Delay condenser retube approximately 6 years to FY13 and then use Alternative 3
Option 1 - Retube with copper in FY09 and install deep-bed deminerlizers in FY11
Option 2 - Retube with stainless steel (Sea-Cure) in FY09
Option 3 - Retube with titanium in FY09
Option 4 - Retube with modular stainless steel bundles (Sea-Cure) in FY11
Option 5 - Retube with modular titanium bundles in FY11
Option 6 - Retube over 2 outages with titanium - not considered viable due to 1) outage penalties would double, 2) thermal expansion differences from different materials

Recommended Option

Option 3 - Retube with titanium in FY09

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Cost Benefit Analysis – Results

Present Value Details - Magnitude and Sensitivity of Input Assumptions

	FY07 $M NPV					
Impact/Description	**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Installation Costs	$ (23.0)	$ (49.0)	$ (24.0)	$ (28.4)	$ (55.3)	$ (70.5)
Installation Outage Impacts/ Incl Dose	$ (18.7)	$ (24.9)	$ (32.7)	$ (32.7)	$ (85.0)	$ (85.0)
Chem Decon (incl dose)	$ (11.7)	$ (8.0)	$ (8.0)	$ (8.0)	$ (11.7)	$ (11.7)
Fuel Failure Risk	$ (5.8)	$ (3.0)	$ -	$ -	$ (3.0)	$ (3.0)
Projected Downpowers for Tube Leaks	$ (10.2)	$ -	$ -	$ -	$ -	$ -
Reduced Dose	$ 17.5	$ 19.4	$ 19.4	$ 19.4	$ 17.5	$ 17.5
(Derate)/ Increased Generation	$ (13.6)	$ -	$ (25.6)	$ (15.8)	$ 69.6	$ 69.6
Added ongoing Inspection Costs for Modular	$ -	$ -	$ -	$ -	$ (1.8)	$ (1.7)
Total	**$ (65.5)**	**$ (65.4)**	**$ (71.0)**	**$ (65.5)**	**$ (69.6)**	**$ (84.7)**

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Recommended Options

- Sea Cure material selection NOT recommended by our materials engineers
  - Tube processing consideration – ability to find defects/complex material mix
  - Future inspection challenges – ability to find defects
  - Titanium proven performer in many more installations

Option 3 – pro's and con's relative to modular replacement

- Pros
  - Relatively Low Capital Costs
  - Easier Installation – can be accomplished in FY09
  - Technical and Installation risk - Low
  - Gets copper out of the plant the quickest
    - Getting dose reduction ASAP
- Cons
  - Summer Derate possible now and with Extended Power Uprate
    - Due to unknowns not considered in business case
    - If/When EPUR occurs evaluate further for other mods to gain back potential losses
  - Muntz Metal tube sheet concern
- Risks
  - Titanium availability could drive to R20

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Cost Benefit Analysis – Results

Present Value Details - Magnitude and Sensitivity of Input Assumptions

	FY07 $M NPV					
Impact/Description	**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Installation Costs	$ (23.0)	$ (49.0)	$ (24.0)	$ (28.4)	$ (55.3)	$ (70.5)
Installation Outage Impacts/ Incl Dose	$ (18.7)	$ (24.9)	$ (32.7)	$ (32.7)	$ (85.0)	$ (85.0)
Chem Decon (incl dose)	$ (11.7)	$ (8.0)	$ (8.0)	$ (8.0)	$ (11.7)	$ (11.7)
Fuel Failure Risk	$ (5.8)	$ (3.0)	$ -	$ -	$ (3.0)	$ (3.0)
Projected Downpowers for Tube Leaks	$ (10.2)	$ -	$ -	$ -	$ -	$ -
Reduced Dose	$ 17.5	$ 19.4	$ 19.4	$ 19.4	$ 17.5	$ 17.5
(Derate)/ Increased Generation	$ (13.6)	$ -	$ (25.6)	$ (15.8)	$ 69.6	$ 69.6
Added ongoing Inspection Costs for Modular	$ -	$ -	$ -	$ -	$ (1.8)	$ (1.7)
Total	**$ (65.5)**	**$ (65.4)**	**$ (71.0)**	**$ (65.5)**	**$ (69.6)**	**$ (84.7)**

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Cost Benefit Analysis – Specific Assumptions

		FY07 $K					
Other Cost Impacts Assumptions		**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Radiation							
Radiation Impacts Retubing (man-rems)		12	12	12	12	60	60
Cost per Man-rem		$ 25	$ 25	$ 25	$ 25	$ 25	$ 25
Total Radiation Impacts		$ 300	$ 300	$ 300	$ 300	$ 1,500	$ 1,500
Installation Outage Impacts							
Incremental Outage Impact (Days)		25	25	33	33	85	85
Lost MWH from Outage Impact	1107	664,200	664,200	876,744	876,744	2,258,280	2,258,280
Annual Derate/Increase							
Lost MWH from Summer Derate		17133	-	27,818	17,133	-	-
Increased Generation						$ 91,542	$ 91,542
Additional Annual Inspection Costs							
Per Outage		0	0	0	0	220	200
Chemical Decon		$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367
Radiation Impacts from Decon (man-rems)		15.00	15.00	15.00	15.00	15.00	15.00
Radiation Benefits for Copper Removal							
Man-rems Saved		50	50	50	50	50	50
Value of Man-rems saved		$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250
Fuel Failure Risk from copper							
Probability of failure Annually prior to retube post FY09		0.05	0.05			0.05	0.05
Cost of a failure							
Direct Cost		$ 4,000	$ 4,000			$ 4,000	$ 4,000
Fuel Purchase		$ 25,000	$ 25,000			$ 25,000	$ 25,000
Root Cause Analysis		$ 4,000	$ 4,001			$ 4,000	$ 4,001
Radiation Costs of a failure		$ 425	$ 425			$ 425	$ 425
Total Fuel Failure Costs		$ 33,425	$ 33,426			$ 33,425	$ 33,426
Annualized Cost for Fuel Failure Risk		$ 1,671.3	$ 1,671.3			$ 1,671.3	$ 1,671.3
Downpowers for Condenser Problems Post FY09							
Direct Costs		605					
Annual Average Lost Generati	40	$ 2,358	Based upon 6 in the last 3 years due to co				
Total Downpowers Loss and Cost		$ 2,963	Estimated				

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BPA
APR 26 2007
RICHLAND

April 24, 2007

Mr. Andy Rapacz
Contract Generating Resources Manager
Bonneville Power Administration
Mail Drop 1399
PO Box 968
Richland, WA 99352

Dear Andy:

Our response to the 16 main condenser upgrade/replacement questions is listed below. For ease of reference, the original questions which were contained in the letter dated March 16 are listed in bold prior to each response.

1. **What is the estimated end-of-life (using the HEI methodology) for the current condenser assuming proper maintenance? Given the 40-year design life of the existing condenser, and the full eddy current testing scheduled during R18, would these results (as well as the R18 fuel inspection results) provide valuable information that either would affirm the current recommendation or indicate that the timing of the condenser replacement should be re-evaluated?**

   End-of-Life Estimate
   The HEI curve was previously provided and is included as Attachment A for your convenience. Predictive uncertainty exists in end of life projection for the Main Condenser. A best effort attempt is provided to define the current condenser limits. No consideration for unit de-rate or reliability has been assumed in the following response.

   - The current condenser is designed to the HEI (Heat Exchanger Institute) standard for surface steam condensers.

- Since there is no methodology for the end of life, the HEI design guidelines can be applied and used to "box in" and better estimate the end of life, or limits, which may result in increased tube failure.

- For the end of life curve three HEI design limits were addressed.
  - The condenser is designed with 10% excess tube capacity. This is a maximum design limit for tubes plugged because of the significant thermal efficiency loss.
  - The actual maximum plug limit is 7.8% based on inlet flow velocities reaching 8 feet/second. This tube material limit will result in significant tube plugging as a result of inlet end erosion.
  - Long term tube uniform thinning "boxed area" eventually will result in increased tube deflection and bending, exceeding HEI design limits for ligament design and subsequent mid span collision and tube failure. This is a long term issue rarely experienced since the other mechanisms are predominant. This is caused by uniform loss of material from cooling water and steam side erosion.

- The chart shows the actual plugging data with the current condenser plugged at 3.9%. An assumed linear regression through this data was made to represent the worst case end of life point. This would indicate that the flow velocity limit would be achieved by 2018 or within 11 years. With continued focused maintenance, a life greater than 11 years can be achieved. It is highly unlikely that plant life extension could be achieved with the current condenser.

- Any changes in the following can change the outlook and rapidly shorten the remaining useful life.
  - Increased occurrence of stress corrosion from water chemistry excursions.
  - Increased Dezincification (pitting attack), which is a function of tube cleanliness and scaling
  - Steam impingement thinning influenced by steam trap and balance of plant valve reliability.
  - Gross Foreign Material Exclusion (FME) problems.

Conclusion

As stated in the Main Condenser White Paper and various verbal discussions, the primary driver for condenser replacement is not end-of-life projections. Primary drivers surround sound operational excellence and nuclear safety. Fuel integrity, primary system chemistry control, radiation safety and vessel internal protection are primary financial and safety risks that warrant improved risk management. Industry operating experience in these areas has continued to progress, with

standards continually rising. Since the Davis Besse head degradation event, the industry is increasingly intolerant of utility operators that are out of compliance with the BWR Vessel Internals Guidance. Likewise, a new US industry initiative is elimination of fuel failures across the industry by 2010. In both cases, the industry is willing to burden the financial impact to ensure the US Nuclear Reactor Program maintains high margins of safety.

Using our best nuclear judgment, it is inappropriate to delay condenser replacement. Placing it into the Energy Northwest FY08 budget communicates to BPA and the region our intent to move forward promptly. Data from the R-18 Refuel Outage is unlikely to have an impact on our decision, but will certainly be factored into the ongoing decision process.

2. **What are the projected costs for continuing regular refueling outage maintenance on the existing and new condenser?**

Existing bi-annual condenser maintenance costs:
Tube cleaning = $385K
Eddy current testing = $576K (100% testing)
Dimple plugs = $185K (100%)
Total cost = $1146K

NOTE: These costs do not include increased resin, disposal, labor or de-rate costs if a leak occurs during the operating cycle.

New bi-annual condenser maintenance costs:
Tube cleaning = $385K (at least first cycle)
Eddy current testing = $57.6K (10% first cycle – focused on periphery tubes)
Dimple plugs = $185K (100%)
Total cost = $627.6K

The refueling outage maintenance costs for an admiralty brass condenser is well in excess of that for a titanium condenser. Both require a similar type of maintenance, but titanium is much more robust and the extent of the maintenance is expected to be substantially less. A key difference is that titanium is almost a pure metal; pitting, erosion and corrosion are not expected failure modes. Likewise, titanium is more resistant to FME type failures. Therefore the testing for titanium tubing would be started at 10%. The testing could be reduced or eliminated as experience is gained through each additional operating cycle, which would reduce the above costs for the new condenser accordingly.

Conversely, Admiralty Brass tubing has issues with pitting, cracking, erosion, and is highly susceptible to FME type failures. The above outage costs for the existing condenser are required to extend the mean time between failure (MTBF) for tube leak repairs from 1 to 2 years, decreasing the likelihood of a mid-cycle leak.

3. **What is the estimated life of the new condenser including a comparison with industry experience that supports the estimate? What is the degree of confidence the new condenser will last to the end of plant life in 2043 assuming license extension is implemented?**

As stated in the Sargent & Lundy Upgrade Scoping Study, the proposed solution is to get through the license extension. Based on our independent review of operating experience, we concur that condenser retube with titanium should support reliable operation through 2043.

Extensive data on condenser material operating experience is provided in the Main Condenser Upgrade Scoping Study. Many utilities that have upgraded their condenser have not reached (or approached) what would be considered the end-of-life for their condenser. Current operating experience validates titanium to be a very reliable material for long-term reliable condenser operation. Two specific examples include:

- Songs 2 and 3 have been operating since 1983/4 with titanium tubing with a muntz metal tube sheet. Water and steam erosion and corrosion have not been a problem with the titanium tubes. Currently, there is a problem with the carbon steel stakes and some are planned to be replaced.

- Diablo Canyon has also been operating since the early 1980's with titanium condenser tubes.

  These two plants and others have had very good performance with titanium tubing. These plants each have about 25 years experience and expect the tubing to last through plant life extension.

4. **What is the expected plant energy loss due to condenser driven de-rates during summer months with a new retubed titanium condenser?**

The expected de-rates for a titanium tube condenser is nearly the same as the current admiralty brass condenser. The de-rates that the plant has experienced during the summer months would generally be the same with titanium. This is based on the estimates contained in the replacement study document and interpolating for current condenser tube plugging of approximately 4.1%.

The resultant delta is approximately 5000 MWhrs or 4 full power hours for the titanium tube condenser. An improvement in the cleanliness factor and chemistry control could help in improving the heat rate for the titanium tube condenser. Additionally, replacement of the fill material for the remaining three cooling towers could improve the circulating water cooling efficiency.

5. **Based on industry experience, what is the projected number of tubes that will require plugging for the new condenser through end of plant life assuming license extension is implemented and the corresponding annual energy losses expected due to condenser driven de-rates? What is the likelihood and number of infant mortality tube failures in the new condenser?**

   The industry has had very good experience with titanium tubing. Infant mortality has not been an issue. The tubing is manufactured to high quality standards, virtually eliminating base material defects. Likewise, workmanship is controlled better than the 1970 era condensers. Available industry experience with titanium condensers does not currently indicate the need for extensive tube plugging over the life of the condenser.

   Condenser de-rate information associated with thermal heat rate losses is provided in the above answer. Other condenser de-rates due to leakage will be substantially reduced, if not totally eliminated, following project completion.

6. **What is the ability of the new condenser design to support future power up-rates if up-rates are implemented? What are the other plant equipment upgrades and associated costs that could be implemented to mitigate power de-rates from an up-rated power level condition?**

   As stated in the Sargent & Lundy Condenser Upgrade Scoping Study, the new condenser design does not change the conclusions of the original study for future power up-rates (EPUR up to 3988 MWt). However, power up-rate may exacerbate the need for plant de-rates during summer months. Potential plant equipment upgrades have not been evaluated to date for de-rates after tube replacement, but previous evaluations for current de-rate conditions have identified potential upgrades to the steam jet air ejectors (SJAE) by increasing the capacity of the second stage steam jets or increasing the capacity of the SJAE intercondenser. Based on current de-rate frequency and duration for the existing condenser, these were determined not to be cost effective (first option $150K and second option $500K, with some efficiency loss while at full power). These options as well as others can be evaluated based on future conditions.

7. **Please provide a summary of the number and cycle of occurrence of condenser tube failures at CGS separated into the following causal categories: debris induced, steam impingement, vibration induced, general erosion, SCC and others?**

   Until the last few years, the causes for condenser tube leaks have not been well documented. The total number of tubes plugged through R-17 is 2,017 with the following categorizations as best possible:

   Debris induced (circ water side): 42
   Steam impingement: 222
   Vibration induced: 0
   General erosion / SCC: 1,433
   Other: 320

   Note that "general erosion / SCC" includes tubes plugged during outages based on NDE exam. This population could not be separated between SCC and general erosion based on current information. The "other" grouping includes tubes that scrapers became stuck in, tubes identified as bent, tubes removed for inspections and those identified as "damaged" with no further notation.

8. **Describe the actions taken to address the root cause of FME problems documented in PER 204-0811 and how these actions are expected to prevent recurrence of foreign material caused leaks in the new condenser?**

   Based on the root cause analysis, the foreign material of most concern is tie wraps, especially those that had been used and clipped. These "clipped" tie-wraps frequently become stuck at the #1 tubesheet and then cause fretting damage at that end of the tube until a pinhole leak develops. The corrective actions implemented included development of enhanced FME zones at the cooling towers and inside the circulating water pump house. Additionally, though not a formal CAP from PER 204-0811, the fill material has been replaced on towers 1A, 2B and 2C. This action resulted in the removal of the tie-wrap materials of concern noted above and replaced them with a stainless steel tie-wrap less susceptible to failure. The replacement of the fill material on the remaining three towers (1B, 1C and 2A) is not currently scheduled and is estimated to cost approximately $2 million per tower. Based on the harsh operating environment of the Cooling Towers and nature of current or future water screens, the best method for eliminating tie-wrap related FME is to rebuild the remaining Cooling Towers.

   The effectiveness of implemented corrective actions was measured by the cleanliness of the waterboxes upon initial entry during tube plugging evolutions

and outages. There was evidence of biological materials and some cooling tower parts, but no tie-wraps or tie wire pieces were found upon initial entry and inspection of the tubesheets. Further cleaning of the circulating water system is scheduled in R-18.

Finally, the source of FME can be substantially reduced, but as with any raw water system, cannot be totally eliminated. Expectations for the new condenser are that these actions combined with the increased toughness of the new titanium tube material will substantially decrease the potential for tube leaks due to foreign material intrusion.

9. **Please provide a summary of the number and cycle of occurrence of fuel failures at CGS separated into the following causal categories: foreign material induced fuel fretting, copper interaction with fuel cladding, condenser leakage (Feedwater contaminants) and others.**

Columbia Generating Station (CGS) has experienced no fuel defects in the current or previous 2 operating cycles. CGS did have one minor fuel failure in cycle 15 (year 2000) due to foreign material fretting. Prior to cycle 15, fuel failures at CGS were identified in cycle 5 (year 1989) due to (1) crud induced localized corrosion (CILC) when the industry was in a discovery phase on the copper related mechanism, (2) fuel fretting and (3) an unknown cause.

CGS experienced fuel corrosion during cycle 15 due to a condenser tube leak resulting in a reactor water chemistry excursion event. CGS formed a multi-disciplined Fuel Corrosion Task Force with internal and external experts to evaluate the fuel corrosion. CGS did not experience any fuel failures from the event. Substantial organizational concern existed that fuel damage could occur, leading to an extended outage for extensive fuel reconstitution or replacement. Fortunately, fuel failure did not result. Much of our current source term leading to high dose rates can be directly correlated to the elimination of zinc injection to prevent further corrosion of the fuel for the subsequent operating cycle to minimize the potential of fuel damage.

In summary:

Debris fretting : 2 failures; 1 in cycle 5, 1 in cycle 15
Copper interaction with fuel cladding: 2 failures in cycle 5
Condenser leakage: 0 failures, 1 or more "substantial near misses" in cycle 15
Other: 1 in cycle 15 of unknown cause

Additionally, CGS had fuel failures in cycle 3 and 4 that were never identified. These could have been similar to the cycle 5 failures. It appears that one failure was removed at End of Cycle 3. During cycle 4, operation 1-3 failures were

thought to be present, but never identified. It appears that one or more of these failures were removed at End of Cycle 4, but some remained based on indications of failed fuel at beginning of Cycle 5.

10. **Please provide the projected number of fuel failures between now and end-of-life (as estimated in question 1) of the current condenser separated into the following categories: foreign material induced fuel fretting, copper interaction with fuel cladding, condenser leakage (Feedwater contaminants) and others. Also, provide the projected number of fuel failures expected during the lifetime of the new condenser separated into the same categories.**

There are 3 primary fission product barriers to radiation reaching the public;
1. Primary Containment
2. Secondary Containment
3. Fuel Cladding.

The US industry has historically protected Primary and Secondary Containment barriers extensively, while tolerating some level of fuel failures at many units. Over the last several years, this view has changed and the Chief Nuclear Officers established a US industry goal of 'ZERO Fuel Failures by 2010'. The level of performance previously tolerated is no longer acceptable.

It is our responsibility to take the necessary precautions and actions to prevent future fuel failures. Based on this premise, we do not expect any future fuel failures since we will act on known challenges. By performing a prediction of future fuel failures, we could be perpetuating an operating philosophy that preventable fuel failures might be tolerated.

Finally, predictive tools to answer the question do not exist, so we will not project fuel failure rates. The best investment that CGS can make to minimize future potential fuel failures is modifying the condenser to eliminate impurities reaching the primary system and minimizing copper.

11. **What are the estimated levels of Feedwater copper before and after condenser tube material replacement? Will the copper levels after tube replacement meet all industry guidelines?**

Copper before: 0.20 ppb (min), 0.35 ppb (max)
Copper after: 0.02 ppb < 0.05 ppb (industry standard)

The above projection has been confirmed through stations with Muntz metal tubesheets

12. What is the estimated dose reduction relative to collective radiation exposure (CRE) performance indicator separated into the following categories: dose reduction due to condenser tube material replacement, dose reduction associated with chemical decon during refueling outages, dose reduction associated with the cobalt reduction effort and dose reduction associated with fewer tube leak repairs? What is the estimated CRE performance indicator after R19 and after R20 if the condenser is not replaced and the cobalt reduction efforts proceed and chemical decons are conducted as part of future refueling outages?

Dose reduction can be identified for an activity, like chemical decontamination. The complexity comes about from the rate of re-deposition based on other variables. To be successful in achieving industry accepted source term levels, excellent primary water chemistry, fuel performance, cobalt reduction, and chemical decontamination must all work together. To respond to your question, the following data is provided with the caveat that use of any number without putting it into a very dynamic context could cause one to reach inappropriate conclusions.

- Dose reduction due to condenser tube material replacement is not a readily quantifiable value. It is expected that plant dose rates would increase more rapidly with copper present. How much is unknown since plants having had this experience have quickly corrected the copper input.

- Dose reduction associated with chemical decon during refueling outages:
  - R-18, 64Rem
  - R-19, 50Rem

- Dose reduction associated with cobalt reduction effort is unknown. This prevents future build-up and plants that have done this are showing steady dose rates from cycle to cycle.

- Dose reduction associated with fewer tube leak repairs on-line is 6-8Rem/year

- Estimated CRE performance indicator after R-19 and R-20 if the condenser is not replaced, the cobalt reduction efforts proceed, and chemical decontaminations are conducted can expect 3rd or 4th quartile for the next 4 years (160-180 Rem).

13. Describe EN's enhanced ability to detect and repair condenser tube leaks and confirm whether this is included in the cost benefit analysis business case?

The ability to detect and repair condenser tube leaks was not included in the cost benefit analysis. The cost benefit analysis was based on increased reliability of the condenser, not enhanced detection of leaks.

BPA staff is aware of our capabilities in this area, so a written description of our capabilities has not been provided.

14. **What is the total cost estimate to replace the condenser with the option EN has chosen excluding the cost of replacement power? Based on the past history of cost increases in major plant projects including ISFSI, HWC, DEH and FWH replacement, provide the degree of confidence associated with the cost estimate.**

Cost break down for condenser retubing with titanium tubes:
Material costs: $11,000,000
Contractor costs: $10,120,000
EN costs: $ 3,500,000
Decon costs: $ 3,500,000
Total: **$28,120,000**

These costs did not include a turnkey contractor or escalation.

Factors that can adversely impact the estimate include labor availability, material demand, cost for schedule reduction initiatives, and costs associated with a 2-outage schedule. Taking these into account, the costs could increase as much as 25%. Over the coming year, additional schedule, procurement, and planning activities will increase the accuracy of the estimates and our FY09 budget will be much more precise.

15. **Please provide a copy of the of the cost benefit analysis business case for the condenser replacement including a summary explaining the assumptions that were used and verified in the analysis.**

Refer to Attachment B.

16. **Given the net present value of negative $65 million for the chosen replacement option, please describe the offsetting factors (i.e., regulatory commitments, INPO recommendations, etc.) that make this a viable project from a cost benefit perspective. Are there any other alternative options including condenser replacement deferral to end-of-life estimated in question 1 that result in a less negative, zero or positive net present value?**

The viability of this project is provided in the Main Condenser White Paper, dated June 2006.

Per the cost benefit analysis business case provided (see response to question 15 above) the selected option has the least negative present value. The business case was performed in a manner to compare alternatives. Different assumptions and evaluation methods would be required if we were to evaluate an option of such a lengthy deferral. For example, one extended outage and fuel replacement campaign would provide an immediate payback. We do not believe it is prudent to evaluate a deferral of this length, but did include a 'Base Case' (6 year deferral) evaluation at the request of BPA.

The option of deferring to end-of-life was not included in the original analysis as it would increase the probability for fuel failure, vessel internals degradation, and adverse dose, with significant consequences to the station, the industry, and the region.

If you should have any additional questions or concerns, please contact me at (509) 377-4333.

Regards,

W. Scott Oxenford
Vice President, Technical Services

dc

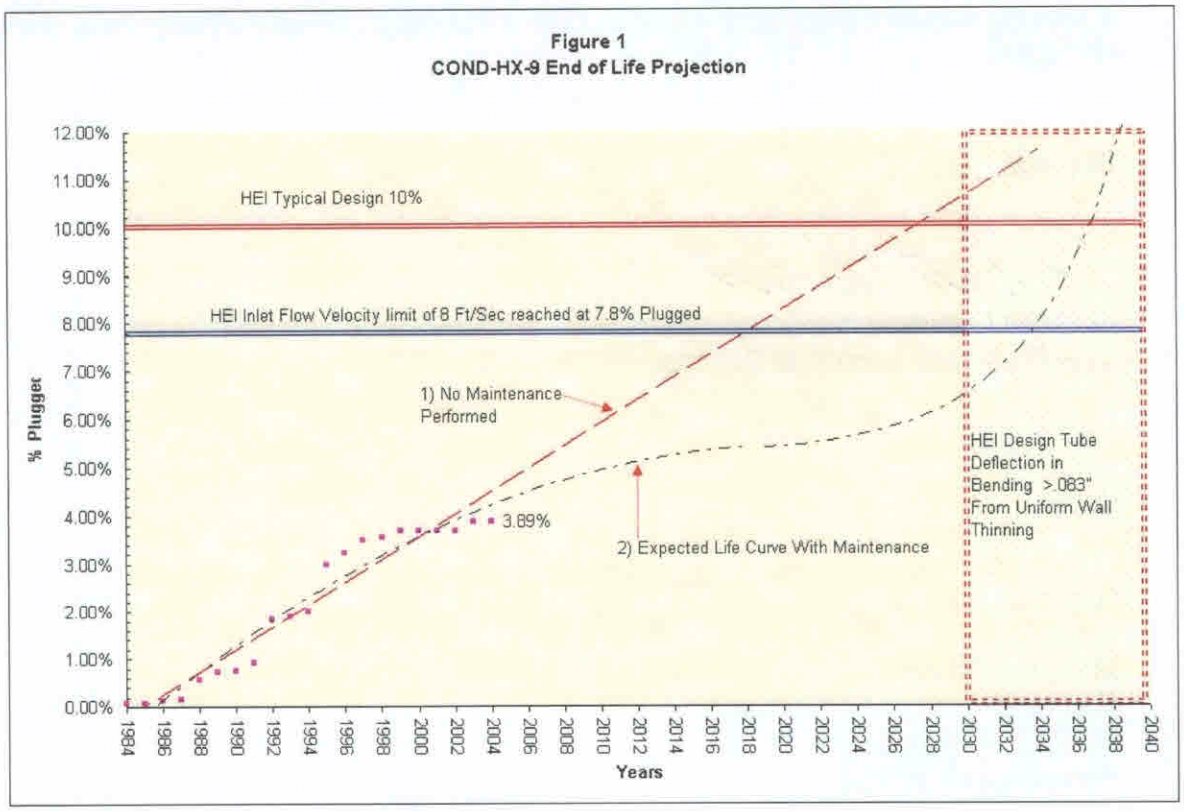
DISTRIBUTION LIST:

Mr. Steve Oliver
Bonneville Power Administration
905 N.E. 11th Avenue
Portland, OR 97232

Attachment A

There has been a lot of speculation regarding the end of life for the condenser and the figure below is an attempt to frame the perspective with a projection of the life curve. The HEI design criteria is used to help define the limits based on increased flow rates and uniform thinning, resulting in exceeding the design tube deflection towards the end of life.

The chart below is a best guess of the end of life projection for the condenser tubes. This chart displays the actual percent of tubes plugged and a regression through the data, with limiting condition being flow rate and uniform thinning at the tail end of the life cycle. No consideration for loss or unit de-rate has been assumed. The 7.8% plugged should be considered to be the limit for useful life. The range for the condenser end of life should be considered to be between 2018 worst case and 2033 best case. Plant operation chemistry and maintenance determine the end point. The emergence of additional SCC or gross steam damage can easily change this outlook and eat up remaining margin rapidly.



Attachment B
(See Next Page)

Energy Northwest

Date: 1/29/07

To: Executive Authorization Committee

From: Joe Frisco Project Manager

Subject: Project Number 00608601 Conceptual Study to Replace Main Condenser Tubing

Executive Summary

The purpose of this business case is to evaluate the Sargent and Lundy Main Condenser Upgrade Scoping Study and prepare cost analysis for replacing the main condenser tubing. The study documents a condition assessment and tube replacement options for improving the reliability of the main condenser at the Columbia Generating Station. The report also discusses the best method to reduce the copper source in the reactor water. The replacement options are evaluated with respect to material and installation costs, maintenance costs, estimated outage durations, thermal performance, ALARA avoidance costs, and lost power revenue.

PHC Project Ranking	**16**
Project Type	**Capital**

Summary Cost Estimate

	FY07 $K					
	Base Case	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Current Estimated Capital Costs	$ 30,586	$ 54,512	$ 25,897	$ 30,586	$ 63,493	$ 80,933
PHC/EAC Approval						

Options Considered

Base Case - Delay condenser retube approximately 6 years to FY13 and then use Alternative 3
Option 1 - Retube with copper in FY09 and install deep-bed deminerlizers in FY11
Option 2 - Retube with stainless steel (Sea-Cure) in FY09
Option 3 - Retube with titanium in FY09
Option 4 - Retube with modular stainless steel bundles (Sea-Cure) in FY11
Option 5 - Retube with modular titanium bundles in FY11
Option 6 - Retube over 2 outages with titanium - not considered viable due to 1) outage penalties would double, 2) thermal expansion differences from different materials

Recommended Option

Option 3 - Retube with titanium in FY09

Background

The goal of the study is to find a cost effective replacement for the main condenser tubing. Sargent and Lundy has issued the final report, titled "Main Condenser Upgrade Scoping Study" dated Dec. 14, 2006. The study documents a condition assessment and tube replacement options for improving the reliability of the main condenser at the Columbia Generating Station. The report also discusses the best method to reduce the copper source in the reactor water.

Columbia has a history of small tube leaks that have been difficult to find and tube failures that have caused seven plant shutdowns and down powers between 2003 and 2006. The main condenser in leakage has been identified as the major factor which challenges reactor water chemistry. Main condenser circulating water in leakage is currently one of the top ten equipment material condition issues at Columbia.

Throughout the plant life and especially in the last four years the leaks have been caused by foreign material that has been introduced in to the circulating water system. The plant has committed to improving the FME controls and performing a 100% eddy current inspection to improve the reliability of the condenser.

The condenser contributes copper in the feed water in the form of soluble copper and insoluble copper. The combination of HWC and Noble Chem appear to cause the copper to plate out on the reactor internal surfaces. The risk of copper plating out on the fuel is largely unknown and could be detrimental. The presence of significant amounts of copper constitutes a substantial increase in the risk of fuel failure should a fuel corrosion event occur.

Strategic Fit and Risk Discussion

Columbia Generating Station cannot maintain feed water copper levels low enough to meet industry guidelines (less than 0.1 ppb). Industry guidelines continue to lower the recommended copper levels. Feed water copper levels have been a documented contributor to fuel rod corrosion and failures.

Columbia Generating station has an admiralty brass condenser and a condensate filter demineralizer system. The combination of these two systems only allows the feed water copper level to be controlled at less than 0.35 ppb.

A do nothing position will eventually result in several of the aging factors related to the condenser causing a limitation on operation at rated power. Fretting at the tube supports, water and steam erosion of the tubing wall, stress corrosion cracking, pitting and circ water velocity will increase as plugging increases which will all cause a sharp increase in the failure rate. This will be considered the end of the condenser useful life.

The addition of the deep bed demineralizer was not estimated with the same confidence factor as the other costs. There is considerable risk that the estimated cost is low. If the deep bed option was the recommended option, a more accurate estimate should be generated.

Both stainless and titanium tubing in a Muntz Metal tube sheet require an impressed current cathodic protection system. Both materials are susceptible to hydrogen embrittlement if an over voltage occurs over several days. There fore the design, maintenance and operation of the cathodic protect system is critical.

The condenser contributes copper in the feed water in the form of soluble copper and insoluble copper. The combination of HWC and Noble Chem appear to cause the copper to plate out on the reactor internal surfaces. The risk of copper plating out on the fuel is largely unknown and could be detrimental. The presence of significant amounts of copper constitutes a substantial increase in the risk of fuel failure should a fuel corrosion event occur. Fuel corrosion has been responsible for fuel failures at other plants in the late 1970's and 1980's. Recent fuel failures have been attributed to cladding corrosion from heavy crud corrosion. At most stations, the corrosion failure mechanism was mitigated by improvement of the nodular corrosion resistance of the fuel cladding, and in many of the cases by removal of the copper source (by replacement of brass condenser tubing or with improved condensate treatment technologies. Following Cycle 15 Columbia experienced a case of enhanced cladding nodular corrosion, but with out cladding failure. The industry and INPO have urged the plants to meet the water chemistry goals from BWRVIP-130. Vermont Yankee and Columbia are the last two US nuclear plants with out a deep bed demineralizer that have copper condenser tubing. The Probability that copper in the feed water, at present concentrations will result in fuel failure is unknown. For the purpose of this evaluation the probability is assumed to be 5% per year and would affect the third cycle fuel. This risk has a severe outcome if it does result in fuel failure. Experience from other plants that have fuel failures would result in the following costs to Columbia; the failed fuel would be examined to perform crud analysis/corrosion thickness analysis and root cause for about $4,000,000, and then an emergency procurement of 100 fuel bundles @$250,000 each. The plant would be in outage for approximately 2 months and the reactor would be defueled to remove the

damaged fuel and then refueled with the new fuel. The direct costs for the outage would be conservatively $4,000,000. The estimated dose for defueling-refueling is 17 Man R. Long term affects would last for several years in the form of higher dose and contamination.

The presence of copper in the reactor water negates the benefits of zinc injection for dose reduction. The shutdown dose rates for Columbia are the highest in the BWR fleet and are showing an increasing trend. The dose estimate increase is approximately 50 man R each outage. A recirc decon ($4,367K)(15manR) is required prior to an outage and one after the copper is removed from the condenser.

Tube vibration assessment by Sargent and Lundy, suggests that the spacing between tube supports is adequate to prevent flow induced vibration, FIV. However a more conservative method suggested staking was required. FIV is minimized through adequate support spacing. A refined tube vibration assessment is recommended if retubing with titanium is selected. The refined assessment may require staking for titanium tubes. The titanium retubing cost comparison does include tube staking since the Sargent and Lundy assessment indicated staking was required by the conservative HEI method. The added cost for staking was $550,000.

If a shell hydro test of the condenser is required to assure the tube to tube sheet joints are leak free, a water management plan needs to be developed. Sufficient water can be made in three days and cleanup time for water disposal is 10 days. Clean up rate is 60,000 gallons/day. This evaluation assumes a successful water management plan is implemented to eliminate the schedule delay of making water and cleanup for disposal. A condenser shell hydro is only required for retubing. An alternate test is to perform a vacuum pull and use sonic means to check for tube leaks.

Risk if not Approved

The material condition of the condenser will degrade to the end of useful life before the licensed life of the plant or the planned license renewal to 2043. A major over haul could be required in about ten years.

The combination of HWC and Noble Chem appear to cause the copper to plate out on the reactor internal surfaces. The copper may increase the risk for fuel failures. The probability of the risk is small but the consequences are large. The copper also causes higher shutdown drywell dose rates. The dose is about 50 ManR per outage and a Recirc decon ($4,367K)(15 ManR) is required prior to an outage and one after the copper source is removed from the condenser.

COST BENEFIT ANALYSIS

Key Assumptions/Qualifications

Note: All alternatives will result in condenser retube

Discount Rate		6.5%
Escalation		3.0%
Man-rem exposure costs $K/man-rem	$	25
FY09 Outage w/o Condenser (days)		35

		FY07 $K					
Other Cost Impacts Assumptions		**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Radiation							
Radiation Impacts Retubing (man-rems)		12	12	12	12	60	60
Cost per Man-rem (FY07$K)		$ 25	$ 25	$ 25	$ 25	$ 25	$ 25
Total Radiation Impacts (FY07$K)		$ 300	$ 300	$ 300	$ 300	$ 1,500	$ 1,500
Installation Outage Impacts							
Incremental Outage Impact (Days)		33	25	33	33	85	85
Lost MWH from Outage Impact	1107	876,744	664,200	876,744	876,744	2,258,280	2,258,280
Annual Derate/Increase							
Lost MWH from Summer Derate		17,133	-	27,818	17,133	-	-
Increased Generation (MWH)						91,542	91,542
Additional Annual Inspection Costs							
Per Outage (FY07$K)		$ -	$ -	$ -	$ -	$ 220	$ 200
Chemical Decon		$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367
Radiation Impacts from Decon (man-rems)		15	15	15	15	15	15
Radiation Benefits for Copper Removal							
Man-rems Saved		50	50	50	50	50	50
Value of Man-rems saved (FY07 $K)		$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250
Fuel Failure Risk from copper							
Probability of failure Annually prior to retube post FY09		0.05	0.05			0.05	0.05
Cost of a failure							
Direct Cost (FY07$K)		$ 4,000	$ 4,000			$ 4,000	$ 4,000
Fuel Purchase (FY07$K)		$ 25,000	$ 25,000			$ 25,000	$ 25,000
Root Cause Analysis (FY07$K)		$ 4,000	$ 4,000			$ 4,000	$ 4,000
Radiation Costs of a failure (FY07$K)		$ 425	$ 425			$ 425	$ 425
Total Fuel Failure Costs (FY07$K)		$ 33,425	$ 33,425			$ 33,425	$ 33,425
Annualized Cost for Fuel Failure Risk (FY07$K)		$ 1,671	$ 1,671			$ 1,671	$ 1,671
Downpowers for Condenser Problems Post FY09							
Direct Costs (FY07$K)		$ 605				$ 605	$ 605
Annual Average Lost Generatic	40	$ 2,358	Based upon 6 in the last 3 years due to condenser tube leaks			$ 2,358	$ 2,358
Total Downpowers Loss and Cost (FY07$K)		$ 2,963				$ 2,963	$ 2,963

Results - Present Value Details - Magnitude and Sensitivity of Input Assumptions

	FY07 $M NPV					
Impact/Description	**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Installation Costs	$ (24.9)	$ (49.0)	$ (24.0)	$ (28.4)	$ (55.3)	$ (70.5)
Installation Outage Impacts/ Incl Dose	$ (24.6)	$ (24.9)	$ (32.7)	$ (32.7)	$ (85.0)	$ (85.0)
Chem Decon (incl dose)	$ (11.7)	$ (8.0)	$ (8.0)	$ (8.0)	$ (11.7)	$ (11.7)
Fuel Failure Risk	$ (5.8)	$ (3.0)	$ -	$ -	$ (3.0)	$ (3.0)
Projected Downpowers for Tube Leaks	$ (10.2)	$ -	$ -	$ -	$ (5.3)	$ (5.3)
Reduced Dose	$ 17.5	$ 19.4	$ 19.4	$ 19.4	$ 17.5	$ 17.5
(Derate)/ Increased Generation	$ (13.6)	$ -	$ (25.6)	$ (15.8)	$ 69.6	$ 69.6
Added ongoing Inspection Costs for Modular	$ -	$ -	$ -	$ -	$ (1.8)	$ (1.7)
Total	**$ (73.2)**	**$ (65.4)**	**$ (71.0)**	**$ (65.5)**	**$ (74.9)**	**$ (90.0)**

ESTIMATED COSTS BREAKDOWN

		FY07 $K					
		Base Case	Option 1	Option 2	Option 3	Option 4	Option 5
Capital Costs by Work							
Retube Condenser/Includes Disposal Costs		$ 28,061	$ 25,011	$ 23,759	$ 28,061	$ 58,250	$ 74,250
Deep Bed Demin		$ -	$ 25,000	$ -	$ -	$ -	$ -
Sales and Use Tax	9%	$ 2,525	$ 4,501	$ 2,138	$ 2,525	$ 5,243	$ 6,683
Total Capital Costs		$ 30,586	$ 54,512	$ 25,897	$ 30,586	$ 63,493	$ 80,933

PHC/EAC Approval

Executive Summary

PHC Project Ranking **16**
Project Type **Capital**

Summary Cost Estimate

	FY07 $K					
	Base Case	Option 1	Option 2	Option 3	Option 4	Option 5
Current Estimated Capital Costs	$ 27,262	$ 54,512	$ 25,897	$ 30,586	$ 63,493	$ 80,933
PHC/EAC Approval						

Options Considered

Base Case - Delay condenser retube approximately 6 years to FY13 and then use Alternative 3
Option 1 - Retube with copper in FY09 and install deep-bed deminerlizers in FY11
Option 2 - Retube with stainless steel (Sea-Cure) in FY09
Option 3 - Retube with titanium in FY09
Option 4 - Retube with modular stainless steel bundles (Sea-Cure) in FY11
Option 5 - Retube with modular titanium bundles in FY11
Option 6 - Retube over 2 outages with titanium - not considered viable due to 1) outage penalties would double, 2) thermal expansion differences from different materials

Recommended Option

Option 3 - Retube with titanium in FY09

ENERGY NORTHWEST

Cost Benefit Analysis – Results

Present Value Details - Magnitude and Sensitivity of Input Assumptions

	FY07 $M NPV					
Impact/Description	**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Installation Costs	$ (23.0)	$ (49.0)	$ (24.0)	$ (28.4)	$ (55.3)	$ (70.5)
Installation Outage Impacts/ Incl Dose	$ (18.7)	$ (24.9)	$ (32.7)	$ (32.7)	$ (85.0)	$ (85.0)
Chem Decon (incl dose)	$ (11.7)	$ (8.0)	$ (8.0)	$ (8.0)	$ (11.7)	$ (11.7)
Fuel Failure Risk	$ (5.8)	$ (3.0)	$ -	$ -	$ (3.0)	$ (3.0)
Projected Downpowers for Tube Leaks	$ (10.2)	$ -	$ -	$ -	$ -	$ -
Reduced Dose	$ 17.5	$ 19.4	$ 19.4	$ 19.4	$ 17.5	$ 17.5
(Derate)/ Increased Generation	$ (13.6)	$ -	$ (25.6)	$ (15.8)	$ 69.6	$ 69.6
Added ongoing Inspection Costs for Modular	$ -	$ -	$ -	$ -	$ (1.8)	$ (1.7)
Total	**$ (65.5)**	**$ (65.4)**	**$ (71.0)**	**$ (65.5)**	**$ (69.6)**	**$ (84.7)**

ENERGY NORTHWEST

Recommended Options

- Sea Cure material selection NOT recommended by our materials engineers
  - Tube processing consideration – ability to find defects/complex material mix
  - Future inspection challenges – ability to find defects
  - Titanium proven performer in many more installations

Option 3 – pro's and con's relative to modular replacement

- Pros
  - Relatively Low Capital Costs
  - Easier Installation – can be accomplished in FY09
  - Technical and Installation risk - Low
  - Gets copper out of the plant the quickest
    - Getting dose reduction ASAP
- Cons
  - Summer Derate possible now and with Extended Power Uprate
    - Due to unknowns not considered in business case
    - If/When EPUR occurs evaluate further for other mods to gain back potential losses
  - Muntz Metal tube sheet concern
- Risks
  - Titanium availability could drive to R20

ENERGY NORTHWEST

Cost Benefit Analysis – Results

Present Value Details - Magnitude and Sensitivity of Input Assumptions

	FY07 $M NPV					
Impact/Description	**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Installation Costs	$ (23.0)	$ (49.0)	$ (24.0)	$ (28.4)	$ (55.3)	$ (70.5)
Installation Outage Impacts/ Incl Dose	$ (18.7)	$ (24.9)	$ (32.7)	$ (32.7)	$ (85.0)	$ (85.0)
Chem Decon (incl dose)	$ (11.7)	$ (8.0)	$ (8.0)	$ (8.0)	$ (11.7)	$ (11.7)
Fuel Failure Risk	$ (5.8)	$ (3.0)	$ -	$ -	$ (3.0)	$ (3.0)
Projected Downpowers for Tube Leaks	$ (10.2)	$ -	$ -	$ -	$ -	$ -
Reduced Dose	$ 17.5	$ 19.4	$ 19.4	$ 19.4	$ 17.5	$ 17.5
(Derate)/ Increased Generation	$ (13.6)	$ -	$ (25.6)	$ (15.8)	$ 69.6	$ 69.6
Added ongoing Inspection Costs for Modular	$ -	$ -	$ -	$ -	$ (1.8)	$ (1.7)
Total	**$ (65.5)**	**$ (65.4)**	**$ (71.0)**	**$ (65.5)**	**$ (69.6)**	**$ (84.7)**

ENERGY NORTHWEST

Cost Benefit Analysis – Specific Assumptions

Other Cost Impacts Assumptions		FY07 $K					
		Base Case	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Radiation							
Radiation Impacts Retubing (man-rems)		12	12	12	12	60	60
Cost per Man-rem		$ 25	$ 25	$ 25	$ 25	$ 25	$ 25
Total Radiation Impacts		$ 300	$ 300	$ 300	$ 300	$ 1,500	$ 1,500
Installation Outage Impacts							
Incremental Outage Impact (Days)		25	25	33	33	85	85
Lost MWH from Outage Impact	1107	664,200	664,200	876,744	876,744	2,258,280	2,258,280
Annual Derate/Increase							
Lost MWH from Summer Derate		17133	-	27,818	17,133	-	-
Increased Generation						$ 91,542	$ 91,542
Additional Annual Inspection Costs							
Per Outage		0	0	0	0	220	200
Chemical Decon		$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367
Radiation Impacts from Decon (man-rems)		15.00	15.00	15.00	15.00	15.00	15.00
Radiation Benefits for Copper Removal							
Man-rems Saved		50	50	50	50	50	50
Value of Man-rems saved		$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250
Fuel Failure Risk from copper							
Probability of failure Annually prior to retube post FY09		0.05	0.05			0.05	0.05
Cost of a failure							
Direct Cost		$ 4,000	$ 4,000			$ 4,000	$ 4,000
Fuel Purchase		$ 25,000	$ 25,000			$ 25,000	$ 25,000
Root Cause Analysis		$ 4,000	$ 4,001			$ 4,000	$ 4,001
Radiation Costs of a failure		$ 425	$ 425			$ 425	$ 425
Total Fuel Failure Costs		$ 33,425	$ 33,426			$ 33,425	$ 33,426
Annualized Cost for Fuel Failure Risk		$ 1,671.3	$ 1,671.3			$ 1,671.3	$ 1,671.3
Downpowers for Condenser Problems Post FY09							
Direct Costs		605					
Annual Average Lost Generatic	40	$ 2,358	Based upon 6 in the last 3 years due to co				
Total Downpowers Loss and Cost		$ 2,963	Estimated				

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Estimated Capital Costs and Lifecycle Costs Net Present Value (NPV) of Options versus Base Case

	FY08 $M (+ or - 25%)				
	Base Case FY19 Retube Titanium	Option 1 FY19 Modular Titanium	Option 2 FY11 Modular SeaCure	**Option 3 FY11 Modular Titanium**	Option 4 FY11 Retube Titanium
Total Capital Costs	$ 67.8	$ 89.4	$ 79.4	$ 89.4	$ 67.8
Installation Risk	High	Moderate	Moderate	Moderate	High
Operation Risk	High	High	High	Low	Moderate
Generation Impact	Negative	Negative	Positive	Positive	Negative
NPV versus Base Case	$0.0	$ 39.7	$ 77.6	$ 103.9	$ 31.4
Recommended Option					

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PER 200-1874

CW Temp Diverges from Cond Temp — 1st thing noticed.

Steam Leak to Main Condenser

Very Unlikely Seen no other indications.

> Steam Cycle OK
> Steam Path OK
> RFW Heaters OK
> Block Valves OK

Continued Monitoring

Condenser Heat Transfer Degraded

Steam Side Air Binding

Very Unlikely

> No New In-Leak
> No LP Sect Impact

Visual Valve Insp
Thermography

CW Side Air Entrapment

Not the Problem

> Vented - No Change

Tube Fouling

Typically doesn't occur in step wise fashion.

only intermediate pressure water box section.

Possible

> 4 Step Changes
> No LP Sect Impact
> No Chemistry Problems

F.O. B Contingency
Tube Cleaning in R-15

Tube Plugging

Unlikely

> No LP Sect Impact
> Uniform Impact in Second Half

F.O. B Contingency
Insp. & Cleaning in R-15

CW Flow Change

ultrasonic measurement the same.

Not the Problem

> No Press Change
> No Flow Change

Geometry Change

Unlikely

> No Dents or Leaks
> Change Must be Big

Forced Outage 'B'

F.O. B Contingency
Insp. & Cleaning in R-15
Thermography

Instrumentation Anomaly

originally thought to be problem c/c'd RTDs + they are ok. computer

RTD Problem

Not the Problem

> No Common Failure
> Vacuum and Metal Temp Confirm Change

Computer or Common Component Problem

Very Unlikely

> No Common Mode or Component Evident

Resistor Installed, TMR

Turbine metal temps. have changed. indicates vacuum has changed.

→ No change since this installed

Description of Problem

Between noon and 16:00 on October 11th the CW temperature dropped slightly with respect to the condensate temperature. Between noon and 16:00 on October 20th the CW temperature dropped again slightly less than a degree with respect to the condensate temperature. Between 14:00 and 18:00 on the 23rd, CW temperature diverged from condensate temperature almost another degree. And, on the 25th between noon and 16:00 the temperatures diverged again bringing the total change between CW inlet temperature and the condensate temperature to almost 3 degrees F.

Plots of CW inlet temperature to condenser vacuum also show a slight change on the 11th followed by changes on the 20th, 23rd and the 25th, in the IP and HP condenser sections. The change is more pronounced in the HP section than in the IP section, and no change is discernable in the LP section. The difference in metal temperatures at the LP turbine exhausts from one end of the condenser to the other has increased from about 10 degrees in early October to about 12.5 degrees in early November.

Plots of CW temperature to gross electrical generation reflect the changes. Plots of Condensate temperature versus gross electrical generation show that the plant is operating as expected.

Apparent Cause:

The apparent cause is still under investigation.

Based on the fact that the CW temperature has diverged from the condensate temperature, a problem with heat transfer in the main condenser would be suspected. However, if heat transfer in the main condenser were degraded, the temperature rise in the circulating water as it goes through the condenser would increase slightly. The data indicates that the opposite has occurred. Because of this, a problem with the instrumentation was suspected. The evidence of the LP turbine exit metal temperatures provides another diverse indication that the problem is real.

If the CW temperature rise across the condenser is ignored, then the possible causes for degradation of heat transfer in the main condenser must be explored. However, the most likely causes of degradation require an entry into the condenser to confirm or correct and the magnitude of the losses are too small to justify even a single day of planned outage prior to R-15.

The status of the possible causes is as follows:

Steam Leak to Main Condenser - STATUS: Very Unlikely
Continued Monitoring

Heat Transfer Degradation
- Steam Side Air Binding - STATUS: Very Unlikely
  - Visual Valve Inspection and Thermography
- CW Side Air Entrapment - STATUS: Eliminated as a possible Cause,
- Tube Fouling - STATUS: Possible
  - Forced Outage Contingency Inspection and Cleaning in R-15
- Tube Plugging - STATUS: Possible
  - Forced Outage Contingency Inspection and Cleaning in R-15
- CW Flow Change - STATUS: Eliminated as a possible Cause,
- Geometry Change - STATUS: Unlikely
  - Thermography, Forced Outage Contingency Inspection and Cleaning in R-15

Instrumentation Anomaly
- RTD Problem - STATUS: Eliminated as a possible Cause
- Common Component Drift - STATUS: Very Unlikely
  - TMR installed to monitor

Steam Leaks to Main Condenser

A major steam leak to the condenser could cause the divergence seen between the CW and Condensate temperatures and result in the changes seen in the HP and IP condenser sections. About 15 MWth of steam would have to be dumped to the condenser to cause the temperature diversion seen. This should also cause an increase in the CW delta T across the condenser, contrary to what was recorded.

- Heat balance shows no change in the electricity generated for the recorded condensate temperatures. This indicates that there are no major problems in the in the steam cycle from the hotwell to the generator.
- Walk downs found no steam path problems.
- Condenser block valve temperature data showed no changes in leakage to the condenser.
- Data pulled on feedwater heaters, MSRs, etc. showed no changes in BOP equipment efficiencies. Heater pressures and TTDs did not show any similar step changes.
- Using the WHIP computer model of the Steam cycle we were unable to produce a steam path change that would cause the changes seen in the CW temperature without obvious problems in plant.

Actions in Progress:

1. Data continues to be monitored per normal practice.

Steam leaks are very unlikely to be the cause of the problem.

Air Binding on Steam Side of the Condenser Tubes

A build up of non-condensable gas in the main condenser can cause degradation in the ability to condense steam. In general this problem has the greatest impact in the lowest pressure sections of a condenser.

- No change is seen in off gas flow, indicating that no new in-leakage is occurring.
- The largest impact is seen in the high pressure section rather than LP section

Actions in Progress:

1. There are valves installed in the upper air removal lines from the main condenser. Drawings show these valves to be locked open. A plan is being developed to check these valves to be sure they are indeed locked in the open position. The valves are in a high radiation zone, and based on previous tests with the air removal lines it is believed that at least two of the valves would have to be fully closed for any impact at all to be seen. This combined with the fact that the change occurred in four discreet steps makes this possibility unlikely.
2. There is also the possibility that the internals of the valves have come loose from the valve stem. A plan is being developed to check for this. This is also considered to be an unlikely cause for the same reasons.
3. Plans are being put together to do thermography of the exterior of the main condenser to compare to data that was taken in the early 1990s.
4. Possible means of examining the air removal lines during outage are being explored.

Air binding is unlikely to be the cause of the problem.

Air Entrapment on the CW Side of the Condenser Tubes

Air entrapment on the CW side of the main condenser can cause degradation in the condenser performance if the air bubble gets large enough the upper tubes begin to go dry.

- The circulating water system water boxes were vented at both ends of the condenser. Very little air was trapped and the venting had no impact on the condenser performance.

Actions in Progress:

None

Air trapped on the CW side of the tubes has been eliminated as a possible cause of the problem.

Main Condenser Tube Fouling

We are running longer than we ever have without stopping to clean tubes, so we may be experiencing a fouling phenomenon that we have not seen before. We have not experienced much in the way of biological fouling in the condenser tubes at Columbia Generating Station in the past. A new biological growth is always a possibility.

- WHIP Models indicate that the vacuum in all three sections should be impacted if uniform fouling is occurring. Fouling that is progressively worse toward the HP end of the Condenser would match data except for the expected rise in CW delta T.
- The changes occurred over discreet time intervals on the afternoons of 4 different days. A corrosion inhibitor was added to CW on those four days that is normally added directly to the TSW system. However, it was also added on the 6th, 9th, 13th, 16th, 18th, 27th and the 30th when no condenser performance changes were experienced. This inhibitor is normally added to TSW (and therefore CW) on a continuous basis, so it is not a new chemical.
- No other water chemistry changes were made that correspond to the four days in question.
- Bio-fouling is very unlikely to occur over such short time intervals with no changes between.

Actions in Progress:

1. There is no way to confirm or deny a new type of fouling layer on line. Contingency W/O 01012250 for Forced Outage B to take a qualitative look at the condition of the tubes.
2. Condenser tube cleaning scheduled for R-15.

Condenser tube fouling remains a possible cause of the problem.

Main Condenser Tube Plugging

WHIP Models indicate that all three sections should be impacted if uniform plugging is occurring on both tube sheets. Plugging that impacts only the intermediate tube sheet of the Condenser would match data except for the decrease in CW delta T. A change of the magnitude seen would require the plugging of about 8000 tubes. There are only 48,000 tubes total.

- The changes occurred over discreet time intervals on the afternoons of 4 different days. No known debris causing activities match these time frames.
- The plugging phenomenon would have to be such that little or no plugging occurs in the first half of the condenser, while a great deal of plugging occurs at the intermediate tube sheet.
- Data shows the changes to be uniform across the three CW water boxes. So, the plugging agent would have to miss the first tube pass and then distribute itself evenly across the second.

Actions in Progress:

1. Contingency W/O 01012250 for Forced Outage B to take a look at the condition of the tube sheets.
2. Condenser tube cleaning scheduled for R-15.

Condenser tube plugging remains a possible cause of the problem.

Geometry Change within the Main Condenser

One way to impact the heat transfer capability of a heat exchanger is to change the physical geometry. In this case the change would have to be big; big enough to have the equivalent impact of completely removing heat transfer from 8000 tubes.

- No other indications of baffles coming loose or other geometry changes. No leaking tubes, or large dents in the exterior walls of the condenser.

Actions in Progress:

1. Contingency W/O 01012250 for Forced Outage B to take a quick look inside the condenser.
2. Doing internal Condenser Inspection in R-15.
3. Plans are being put together to do thermography of the exterior of the main condenser to compare to data that was taken in the early 1990s.

A large scale geometry change within the condenser is unlikely to be the cause of the problem.

CW Flow Rate Change

In the winter of 1999, CW-P-1C was removed from service for repairs. This reduced CW flow rate by one third. During this time the CW inlet temperature diverged from the condensate temperature by 5 degrees F. So, to cause the shift of three degrees by changing CW flow would require that the flow rate be reduced by about 20%. In addition, when the CW pump 1C was out of service, the CW temperature rise across the condenser increased by 7 degrees F.

- No change in the CW inlet pressure to the condenser was seen during any of the apparent changes in CW temperature. This would indicate that no significant change in CW flow has occurred.
- Each of the cooling tower risers is outfitted with connections for ultrasonic flow measurements. These measurements were taken and compared with previous readings. The readings for overall flow in the CW system agree within the uncertainty of the measurements with readings taken previously. The previous readings were taken in 1995.
- In the current case the CW temperature rise across the condenser has decreased.
- An increase in CW flow could cause the decrease in CW temperature rise across the condenser, but it would result in slightly better condenser performance and the CW temperature would get closer to the condensate temperature; the opposite off what has been experienced.

Actions in Progress:

None

CW flow rate change has been eliminated as a possible cause of the problem.

Instrumentation Anomalies

- The computer data, which is amenable to time based trending, shows multiple indications changing in unison. Study of the instrument connections and computer collection of the data revealed no clear possibilities for a single common device to be causing drift in the set of signals seen.
- Chart recorded metal temperatures confirm the overall changes in vacuum readings. The metal temperatures are not connected to the process computer systems.

Actions in Progress:

1. Installed Resister in place of one CW RTD to definitively confirm or eliminate this possibility if another step change occurs. (TMR# 200-016)

Instrumentation anomalies are unlikely to be the cause of the problem.

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Quality Assessments Initiated [ ] Yes

Followup Assessment of Operability [ ] Yes [X] NA

Permanent Equipment Disposition Classifications
[ ] Permanent Accept-As-Is [ ] Permanent Repair [ ] Rework [X] NA

Equipment Classification: Quality Class: [X] 1 [ ] A [ ] 2 [ ] G
[X] Safety Related [ ] ASME [ ] NA

Previous problems or generic impact discussed [X] Yes [ ] NA

Significant: [ ] Yes [X] No | Number of interim Corrective Actions: 0 | Number of permanent Corrective Actions: 5

Cause Determination Codes

[ ] No Cause Necessary [ ] Unknown (UNKN), Justify in comments [ ] Assumed Risk (AR01), Justify in comments

DESCRIPTION	ORG	PROC	KEY	O&P	HE/IA	GEMS
Inappropriate Action: Indications of accelerated corrosion on cycle 15 fuel	MUL			EQ07		

Comments:

MANAGEMENT SUMMARY

Fuel inspections during R15 (Refueling Outage 15) indicated accelerated corrosion, primarily on 1- and 4-cycle bundles. Higher than normal oxide thickness and indications of spallation existed (most of the spallation observed was a result of aggressive brushing) on both of the 4-cycle discharged bundles inspected. Nodule formations existed on all inspected 1-cycle bundles. PER 201-1033 was issued to address this observation, and in particular, the operability of the fuel in the Cycle 16 core in light of the apparent accelerated corrosion. Westinghouse performed an updated design evaluation prior to startup, to justify Cycle 16 startup and operation (Reference 1). A Fuel Corrosion Task Force was formed immediately following the R15 fuel inspection, to evaluate the root cause. A follow-up inspection was performed in October / November of 2001. Following the October/November fuel inspections, the Task Force continued the investigation into the fuel corrosion root cause. After May of 2002, the Task Force was dissolved and the work of the Task Force continued under the Fuel Corrosion Resolution Project, with the Task Force members forming the core of the Project team. This PER resolution summarizes the outcome of the root cause investigation, which is now being finalized. A great deal of progress has been made in determining the root cause, and a main hypothesis is summarized herein with respect to the overall mechanism. The initial draft of the Reference 2 draft report was completed in May, and captures the extent of evidence and knowledge obtained at that point in the ongoing root cause investigation. The understanding of the root cause has improved significantly since that time. The Reference 2 draft report will be edited, updated, and finalized following the conclusion of the root cause investigation.

The primary root cause of the nodule formation and accelerated corrosion is that, during a specific period late in Cycle 15, one or more substances either deposited on the fuel surfaces or caused chemical reactions near the fuel surfaces, leading to nodule formation and accelerated fuel corrosion. While the exact substance or substances involved in causing the nodule formation and accelerated corrosion have not been identified and may never be identified, trends and anomalies in reactor water chemistry during the specific period late in Cycle 15 provide clear evidence that contaminants and impurities were allowed into the reactor water during that period. The clear evidence of water chemistry anomalies and impurities, together with the timing of the discovery of nodule formations and accelerated corrosion soon after the water chemistry trends existed and with the previous absence of such corrosion problems, constitutes substantial circumstantial evidence that the water chemistry problems caused initiation of nodule formation and accelerated corrosion. It is concluded with high confidence that impurities allowed into the water during that period late in Cycle 15 caused initiation of nodule formation and accelerated corrosion. Although elemental analysis of ~ 150 CRUD samples and XRD (X-ray diffraction), Scanning Electron Microscopy, and Inductively-coupled Plasma Atomic Emission Spectroscopy of several CRUD samples have produced extensive data regarding the amount of Fe, Cu, Zn, and other metals in the CRUD deposits on the cladding

Approvals For Permanent Disposition

PER Dispositioner	*JORDHEIM, DP*	*10/17/02*
Dispositioning Manager	*HUMPHREYS, MC*	*10/20/02*

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Quality Assessments Initiated ☐ Yes

surface, it has not provided evidence of other inorganic substances of concern. The presence of a condenser leak, coupled with an observed degradation in condensate filter demineralizer (CFD) performance, resulted in an extended period during Cycle 15 where reactor water chemistry exhibited historically abnormal trends in conductivity and other parameters, such as the concentration of Tc-99m and some other short-lived neutron activation products. Therefore, the condenser leak and CFD performance are important major contributors to the root cause. During the specific period of interest in Cycle 15 it has been noted that the main steam line radiation monitors showed an upward trend, indicating organic intrusion or a change in the oxidation/reduction potential. This indicates that some portion of the contaminants in the condensate from the circulation water (CW) in-leakage were passing through the CFD's and entering the reactor water in sufficient concentration to affect the CRUD and/or oxide layer on the fuel cladding. While this does not identify the substance(s) of concern, it does provide the contaminant source. Detection of a correlated rise in Tc-99m and the other short-lived activation product concentrations, rising main steam line radiation monitor readings, and/or rising reactor water conductivity all provide a good indicator of entry into a period of concern with regard to damaging water chemistry. The increase in concentration of short-lived radionuclides indicates a potential disruption in the fuel CRUD layer during this period.

The increases in Fe & Zn concentrations in the feedwater and reactor initiated in 1996 for recirculation piping dose reduction and compliance with fuel vendor and EPRI guidance may also play a role in the concentration of this unidentified substance(s) in the subcooled boiling region of the core, which is where the peak oxide thicknesses have been measured. Therefore, the Fe and Zn injection may be a contributing cause, though not as important a contributor as the condenser leak and the CFD problems.

This root cause must be considered tentative, in that the substance(s) in question has not been identified, nor are all of the physical mechanisms involved fully understood and defined. However, the presence of several water chemistry trends in the specific period of Cycle 15 mentioned above, together with the timing of the discovery of accelerated corrosion in R15 and with the previous absence of such corrosion problems, provides considerable circumstantial evidence that contaminants in the reactor water during that period initiated the nodule formation and accelerated corrosion. The major contributing causes (condenser leak and CFD performance problems) are understood with sufficient confidence to define CAPs that will form barriers to accelerated fuel corrosion in the future.

Four CAPs were assigned in the original version (Rev. 0) of this PER Resolution. One additional CAP will be assigned with this revision. The CAPs include;
201-2842-01: Implement Reduced Fe and Zn Targets
This CAP was assigned in the original version of this PER Resolution, and will remain in place. The optimization of the Fe and Zn targets is ongoing.
201-2842-02: Perform Copper Reduction Conceptual Study
This CAP was assigned in the original version of this PER Resolution. Given that the improved understanding of fuel corrosion root cause described in this revision does not directly implicate copper, this CAP will be closed. Also, as discussed below under the Generic Implications section, recent events at Browns Ferry show that CILC-like failures can occur without the presence of copper.
201-2842-03: Reduce or Eliminate Condenser Leak
This CAP was assigned in the original version of this PER Resolution, and will remain in place. Plans are underway for re-plugging all plugged condenser tubes in R16, as well as for other leak-repairing measures.
201-2842-04: Optimize Filter Demineralizer Performance
This CAP was assigned in the original version of this PER Resolution, and will be closed very soon due to improved CFD performance.
201-2842-05: Formalize Monitoring of Water Chemistry for Detection of Corrosion-initiating Conditions
This CAP is new with this revision of the PER Resolution, and serves the purpose of assuring continued avoidance of the Cycle 15 water chemistry problems in the future.

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These CAPs will prevent a recurrence of the Cycle 15 water chemistry event, which has not been observed in Cycle 16 operations to date and is not expected in Cycle 17. Therefore, the accelerated fuel corrosion problem is not expected to be ongoing in Cycle 16 and is not expected in Cycle 17, as long as the corrective actions prove effective. Fuel inspections being planned for the R16 refueling outage (WO# 01043824) will serve as an important verification of the accuracy of the root cause and the effectiveness of the corrective actions.

DESCRIPTION OF THE EVENT

In May of 2001, fuel inspections were performed on selected fuel bundles during the R15 outage. The R15 inspection program was initially intended to establish the baseline for fuel performance under the noble metal chemical application (NMCA). The initial R15 inspections were to include visual examinations and oxide measurements for the selected bundles. The inspection scope was to include four bundles; a 1-cycle Material Supplier Demonstration Assembly (MSDA) bundle that was inserted during R14 to evaluate future cladding materials, two 2-cycle bundles manufactured in the Westinghouse ABB Hematite facility, and a 4-cycle bundle. Visual inspection and oxide measurements of these four bundles revealed that accelerated corrosion and delaminating of CRUD existed. As a result, the inspection scope was expanded to include ten fuel bundles; four 1-cycle bundles, two 2-cycle bundles, two 3-cycle bundles and two 4-cycle bundles.

Following the preliminary evaluation of the R15 fuel inspection results, realizing that nodule formation and accelerated corrosion had occurred, it was determined that further inspections were needed. The additional inspection scope was performed in October and November of 2001. The inspections were performed for the following reasons: 1) to augment the data obtained in the R15 inspection, 2) new oxide measurement equipment was used to allow correction for the effect of Zn-containing ferromagnetic CRUD in the oxide thickness measurements, and 3) to collect CRUD samples for elemental and isotopic analysis. Subsequently, the CRUD samples were sent to Battelle Pacific Northwest Laboratories for elemental and isotopic analysis.

ANALYSIS

Fuel Inspection Results:

The problem addressed in this PER resolution is accelerated fuel corrosion. Fuel examinations, together with associated research and analysis of corrosion mechanisms, provided evidence of accelerated 1) localized uniform corrosion, 2) nodular corrosion, and 3) shadow corrosion. Employing change analysis methodology, these three corrosion mechanisms plus another (hydriding) were evaluated as potential causes of the accelerated corrosion. As summarized by Cause and Effect diagrams in the Reference 2 draft report, the Fuel Corrosion Task Force examined the evidence for signs of 1) cladding manufacturing vulnerabilities, 2) water chemistry vulnerabilities, and 3) core design vulnerabilities. The available evidence points to water chemistry vulnerabilities as the most likely cause of the accelerated corrosion, with cladding material/metallurgical vulnerabilities as a contributing factor for the LK3 clad rods (see the first two bullet items below). Results of continued investigation since the initial draft of the Reference 2 report was completed have affirmed and supported this conclusion. Contaminants in the reactor water chemistry caused initiation of nodule formation and accelerated corrosion.

The following is a summary of the results of the additional fuel examinations, observations and measurements documented by the Fuel Corrosion Task Force in performing the evaluation for Root Cause:

Summary of Fuel Examination Results:

+ The R15 inspection indicated accelerated corrosion on 1- and 4-cycle bundles. Indications of cladding spallation as a result of brushing were also observed on 4-cycle discharge bundles. Nodule formations exist

on all 1-cycle bundles. Nodule coverage ranged from 0% to 90%. The nodule coverage is not only dependent on the cladding material type, but also on the relative location in a sub-bundle. Nodule coverage had not been observed (other than limited levels in the natural uranium region only, at the bottom of the bundles) in previous inspections in R13 and R14.

+ The LK3 Gd rod, WQF167-D7, had the highest oxide growth rate of 3.61 microns per GWD/MTU in Cycle 15. A similar fuel rod (WQF168-D7) is currently being irradiated in Cycle 16.

+ The 1-cycle bundles exposed in Cycle 15 showed a markedly increased mid-span peak oxide thickness, as compared to previous CGS inspection results. The peak oxides are located in the span between the first and second spacers. The under-spacer oxide thickness for the 1-cycle rods in Cycle 15 is also higher than typical (for CGS 1-cycle rods, based on previous inspection results), ranging from 31 to 91 microns.

+ The increased oxide thickness for the 1-cycle fuel rods can be attributed to the nodule-like formations on most of the rods inspected, although the coverage varied from rod to rod and along axial locations. This nodule-like formation was not seen in previous fuel inspection campaigns conducted during refueling outages R13 (following Cycle 13) and R14 (following Cycle 14).

+ The 3 and 4-cycle bundles in Cycle 15 showed oxide thickness results that were within the Westinghouse database for comparably exposed rods, however they are at the high end of the database. The under-spacer oxide thickness results for the 4-cycle rods in Cycle 15 were measured in a range from 50 to 69 microns. Some nodules were observed on at least one 3-cycle rod, and some bumpy, nodule like features were observed on the 4-cycle bundle.

+ The ferromagnetic CRUD-corrected oxide measurements for the 4-cycle discharge fuel rods showed oxide thickness that were within the normal band of Westinghouse database, both mid-span and under spacer, trending towards the higher end of the database.

+ From the CRUD analysis data for the 4-cycle bundle WAC076, the total CRUD (metal) loading is highly bottom peaked, with values reaching 11600 microg/cm2 at elevation 496 mm for rod J7 (LK2(+) cladding, UO2 rod). The copper loading is also high, reaching 3930 microg/cm2 at the same elevation. The copper loading from both WAC076 rods scraped is much more bottom peaked than all other bundles in terms of both absolute and percentage loading. This high copper loading and its potential impact on corrosion are believed to follow a different process than the CILC phenomenon in that the accelerated copper deposition started after the bundle had experienced oxide buildup in the previous 3 cycles through the uniform corrosion process.

+ From the CRUD analysis data for the rods in the 1-cycle bundle WQF167, there is a marked increase of copper deposit on the LK3 Gd rod, when compared to a LK3 UO2 rod and to LK2 (+) and LK2+ rods (either UO2 or Gd). Note that this behavior is consistent with past observations of greater Gd rod susceptibility to CILC. The highest copper deposit was found at 667 microg/cm2 for the LK3 Gd rod at the 682 mm elevation. All the rest of the rods had Cu less than 180 microg/cm2. The single LK3 Gd rod that is currently in the Cycle 16 core, WQF168-D7, may be susceptible to CRUD-Induced Localized Corrosion failure due to its expected high Cu deposition based on the observed CRUD data on WQF167-D7. However, WQF168 is now at a burnup beyond that where the risk of CILC failure is highest, and the risk of CILC failure is dropping with each additional day of irradiation (due to dropping bundle power / heat flux).

+ There may be some water chemistry effect on 4-cycle rods that led to delaminating of the CRUD and some spallation of oxide resulting from brushing.

+ The Columbia Generating Station data indicates a general trend of increased CRUD loading (with a few

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exceptions) from Cycle 12 to Cycle 15.

+ Cycle 15 deposits for high burnup fuel rods are highly bottom peaked. This is also true, to a lesser degree, for the Framatome bundle UD8047 (discharged after Cycle 14), rod E-9. Fuel rod WAC076-J7 stands out as the rod with very high CRUD loading towards the bottom of the rod (based upon scraping results).

+ Framatome bundle UD8047 exhibits a relatively high oxide measurement (around 53 microns) even though it was not in the Cycle 15 core and therefore did not see the damaging water chemistry environment late in Cycle 15 (was discharged at the end of Cycle 14). This observation does not negate the root cause statement that the corrosion problem was specific to a period late in Cycle 15. UD8047 has a burnup of about 43 GWd/MTU, which is higher than bundles previously examined. Given that burnup, and the fact that UD8047 has late beta-quenched cladding, it would be expected that it would have experienced some accelerated uniform "threshold" corrosion late in life. Also, while 53 microns is higher than measurements at CGS in the past, it is not much higher and is also not extremely high for a 6-cycle burned bundle. Finally, the extensive nodule formations observed in R15 are clear evidence of something unique having happened during Cycle 15.

+ Generally, the CRUD deposit increases with burn-up. This dependency increased from Cycle 13 to Cycle 15. This is related to the initiation of Fe and Zn injection in Cycle 12. For Cycle 12, the dependency is weak, apparently due to the short time the fuel is exposed to Fe and Zn injection, i.e. it appears to take substantial time/burnup for the CRUD buildup to occur.

+ There is a general trend of increasing copper loading with increasing nodule coverage for 1-cycle fuel.

+ Results of CRUD sample analysis may be useable as evidence of a CRUD restructuring or destabilizing event. During the Cycle 15 period of interest, it was noted that several short-lived radionuclides such as Tc-99m and Cr-51 showed simultaneous increasing trends. This rising trend in short-lived activation products could be the result of a release from CRUD on the fuel surfaces or restructuring of the CRUD. Analysis of the CRUD samples may provide supporting evidence by showing that the CRUD is not the same age everywhere, which would suggest some kind of restructuring or reconfiguration. This theory is undergoing further investigation, and could support the theory of changing chemical reactions at or near the fuel surfaces. The fact that the most unusual and abnormal nodule formations and accelerated corrosion were on 1-cycle and 4-cycle bundles, and not on 2-cycle or 3-cycle bundles, may support this theory.

Reactor Water Chemistry:

Reactor chemistry has been maintained within the BWR Chemistry Guidelines (BWR Water Chemistry Guidelines - 2000 Revision, EPRI, Palo Alto: 2000TR-103515-R2). That is, reactor chlorides average less than 2 ppb, reactor sulfates have been maintained less than 5 ppb and usually less than 2.0 ppb. Reactor conductivity averages 0.15 mS/cm and pH is in the range of 7.5 to 8.0 with most of the values near 7.8. The feed-water copper level has been maintained at 0.3-0.4 ppb, which is higher than the EPRI water chemistry guideline of 0.2 ppb. However, the guideline allows a higher value (< 0.5 ppb) if an engineering evaluation was performed to justify it. It has not been practical to maintain feedwater copper below 0.2 ppb at Columbia because the Admiralty Brass Condenser always provides a 3 to 4 ppb source of copper and the condensate filter demineralizers are not designed to remove the copper to below 0.2 ppb while still removing other impurities effectively, especially with a chronic condenser leak requiring CFD optimization for removal of increased amounts of other impurities. Until the nodular corrosion was observed in R15, the practice of procuring late beta quenched cladding was perceived to be an effective barrier to CILC, such that a focus on CFD copper removal effectiveness at the expense of optimizing chloride and sulfate removeal was not viewed as necessary or appropriate.

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Long-term trends show reactor insoluble iron to be in the range of 2-5 ppb. This is regardless of the level of iron injected. The level of zinc has been maintained at an average of 7 ppb with the injection skid operating. Since iron injection has started, the reactor coolant copper levels have slowly decreased from 20 ppb average to 10 ppb. The copper levels show step changes from one fuel cycle to the next, decreasing to a low of 10 ppb during Cycle 15.

During the period examined, the condenser has experienced leakage allowing water from the cooling tower system to enter the condensate system. The most recent leak started in January 2000 and continues to the present. During R15, and in two other forced outages attempts were made to locate and plug the leak. On each occasion upon reactor restart, following initial indications that the leak was repaired, the indications of a leak returned, in each case leveling off around 125-150 milliliter per minute. Although condenser leaks have occurred on a number of occasions in the past, this is the first time in recent history that a chronic leak has existed over a long period of time.

A copper balance is performed to determine the copper deposition rate in the reactor (which will preferentially occur on fuel surfaces). The trend shows that over time the deposition rate has varied, but during the last half of Cycle 15 the rate increased significantly. This increase appears in June 2000, roughly six months after the start of the condenser leak.

The startup at the beginning of third quarter 2001 shows the effects of noble chemistry treated surfaces in the reactor disrupting the CRUD layers at those surfaces, resulting in the release of significant amounts of CRUD back into solution. All measured reactor metal and activated corrosion products such as Co-60 show sharp increases during plant startup at the beginning of July 2001, and again at the beginning of August 2001 during a restart. In particular, a marked increase in copper deposition was observed in the first several months of Cycle 16 operation. The copper deposition has since dropped off and feed-water Cu has stabilized around 0.3 ppb, and even lower very recently.

Iron injection was started in July 1996 and zinc injection was started September 1996. Since then, feed-water iron has been maintained in the range of 0.5 to 1.5 ppb measured in the feed-water, and zinc in the range of 5 to 10 ppb in the reactor. The iron is measured and controlled in the feed-water since 95% of the feed-water iron deposits on the fuel. Zinc is more soluble and can be controlled by monitoring reactor water.

Following refueling outage 15, iron and zinc injection was suspended, pending further root cause evaluation to assess their collective role in the accelerated corrosion phenomenon. This suspension has resulted in Mn-54 activity returning to the 1995-1996 value, indicating that the vessel CRUD has returned to a lower, pre-injection state of stability for Co ions. Over the same time interval, the reactor copper concentration has increased from 10 to 12 ppb. Iron and zinc injection were started again in May, utilizing lower target levels intended to balance the radiological hazard in the plant with concerns about fuel corrosion effects. The evaluation of iron and zinc levels is ongoing, with CAP 201-2842-01 assigned to pursue the issue and determine appropriate targets for the future.

As per GE SIL 631 the reactor zinc levels have been maintained between 5 and 10 ppb. The feed-water iron levels were raised above 0.5 ppb and at times increased to as high as 1.5 ppb. The injection program is aimed at reducing the reactor soluble Co-60 by holding it in a stable oxide on the fuel formed with iron and to some extent with zinc. The zinc injection (this is depleted zinc also know as DZO) is intended to reduce the amount of Co-60 depositing on the out of core reactor surfaces, that is, the recirculation piping, in an effort to reduce drywell dose during outages.

Beginning in October of 2000 and continuing to about the end of March 2001, the RW conductivity went

through a rising trend that was not mirrored in the FW. The FW conductivity, in fact, remained very flat throughout this period. While the RW conductivity did not necessarily rise to levels well above some past levels, the rising trend at a time when that trend does not appear in the FW is a sign of possible organic or other intrusion. The organic or other material may not have an effect on FW conductivity, but then may break down chemically in the reactor due to temperature and neutron flux, thereby affecting RW conductivity. A trend in main steam line radiation monitor readings is highly correlated that of the RW conductivity. This is also a sign of organic intrusion, or possibly changes to the oxidation/reduction potential. A rising trend in Na-24 in the RW follows exactly with the RW conductivity and main steam line radiation level trends. The Na-24 trend is a possible indicator of material passing through the condensate filter demineralizers. Also concurrent with these trends is a very strong spike in RW sulfates, which indicates in-leakage through the main condenser passing through the CFDs. Finally, RW Tc-99m exhibits a concurrent rising trend in the same time period, reaching levels not seen in at least the last seven years, and possibly never seen in the history of the Columbia plant. Some other short-lived activation products, like Cr-51, Cu-64, and possibly Mn-56 and Zn-65 may also exhibit rising trends during this period of time, though not nearly as clearly as the Tc-99m. The Tc-99m is produced as the decay product of neutron activated molybdenum.

The circulation water (CW) on the cooling tower side may also exhibit some rising trends during this same time period. There is a very clear rising trend in CW alkalinity from about mid-November of 2000 and ending in the second half of March 2001. There are weaker trends in CW conductivity, Ca, and pH, with Ca and conductivity exhibiting weak trends that do not reach levels above those seen in other previous periods. These trends in CW could be due to changing CW management in terms of the number of cycles the CW is treated.

Corrosion Modeling for Cycle 16:

Based on the observed corrosion behavior and the measured oxide thickness and CRUD analysis, a corrosion model has been developed by Westinghouse for predicting the fuel performance for Cycle 16 (Reference 3). This model takes into consideration the enhanced corrosion with nodule like formations at low burn-ups (< 20 GWD/MTU) and the accelerated uniform corrosion at high burn-ups (>40 GWD/MTU). The derived model was fitted to the fuel corrosion model in the Westinghouse fuel performance code STAV7.2 for design evaluations of cladding temperature, fuel centerline temperature, fission gas release, rod internal pressure and cladding permanent strains for Cycle 16 operation. The impact on LOCA analysis due to the increased corrosion was also evaluated. The results of the evaluation performed by Westinghouse demonstrate that Cycle 16 operation remains bounded by the assumptions and constraints established for the Cycle 16 design. The corrosion model developed conservatively predicts a limiting oxide thickness of approximately 90 microns at end of Cycle 16. Note that the Reference 3 Operability Determination was completed before Revision 1 of this PER Resolution, when it was not known that the accelerated corrosion was specific to a period late in Cycle 15. Therefore, the corrosion model and the resulting assumed accelerated corrosion in Cycle 16 are very conservative. In any case, the Reference 3 analysis conservatively supports Cycle 16 operation in the unlikely event that accelerated corrosion is ongoing.

CONCLUSIONS

Based on examination of the data and information summarized above and in the Reference 2 draft report, the following trends are identified:

1) Based on the CRUD analysis, the total CRUD loading has generally increased from Cycle 12 to Cycle 15, consistent with the amount of time the fuel was exposed to the Fe and Zn injection environment. In addition, with injected Fe and Zn, the chemical composition of the CRUD is changed to spinel formation, leading to increased thickness in tenacious CRUD, relative to the amount of fluffy hematite CRUD.

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2) During the extended period of condenser leak (since January 2000), there was an increase in Na and pH. This increased pH and Na, together with Fe and Zn injection, are postulated to decrease the solubility of Cu in the reactor water and thus to increase the Cu deposition fraction on the fuel.

3) The heavy CRUD observed at the bottom of the rods in WAC076 (at about 400 mm elevation) is believed to be due to the deposition process associated with the subcooled boiling occurring toward the bottom of the fuel bundles.

4) The condensate filter demineralizer performance for Cycle 15 shows that following individual maintenance work on two filter demineralizers, the effluent soluble copper and insoluble iron concentration increased. This indicates a decrease in mechanical filtration and in ion exchange efficiency, which corresponds to increased copper deposition in the reactor, increased sodium concentration, elevated reactor pH and increased reactor conductivity. The increased pH, as a result of increased Na, in concert with Fe and Zn injection are postulated to decrease the solubility of Cu in the reactor water and thus to increase the Cu deposition fraction on fuel.

5) Periods of degraded CFD performance coincide with the period late in Cycle 15 where the water chemistry anomalies and trends were noted. Specifically CFDs D and F exhibited increased effluent concentrations and at least D was known to be experiencing mechanical performance problems after a Septa changeout. This directly implicates CFD performance problems as playing a part in the corrosion root cause.

6) The main condenser is known to have been leaking throughout most of Cycle 15, including the period of interest late in Cycle 15 (late 2000 and early 2001). One of the strong rising trends is in RW sulfates, which is normally considered an indicator of condenser in-leakage. The particularly strong trend in RW sulfates during the period of interest late in Cycle 15 may be evidence of an ongoing condenser leak in concert with CFD bypass.

7) There is a foreign utility that had experienced fuel failures that were determined to be a result of not regenerating the resin properly. During the process of regeneration they allowed cation resin to be regenerated using Na instead of the H+. When the condensate metals were exchanged the Na was released instead of the H+, increasing reactor Na and NaOH concentration. At Columbia Generating Station there was an increase in Na, notably from the condenser leak that was present for a long period in Cycle 15. There is test data that identifies certain species such as sodium sulfate, sodium carbonate, along with hydrogen sulfate causing accelerated fuel corrosion. These inorganic materials may be present in the Columbia Generating

ROOT CAUSES AND CONTRIBUTING CAUSES

Primary Root Cause:

The presence of a chronic condenser leak provided a source for one or more potentially damaging contaminants. This leak coupled with an observed degradation in condensate filter demineralizer performance over a period of months allowed the introduction of these contaminants into the reactor vessel. The effect of these contaminants allowed one or more substances to either deposit on the fuel surface or cause chemical reactions near the fuel surface during the specific period late in Cycle 15. The resulting water chemistry impurities initiated nodular formation and accelerated corrosion on the once burned bundles, and accelerated corrosion on higher exposure fuel. While the exact substance or substances involved have not been identified and may never be identified, trends and anomalies in reactor water chemistry during the specific period late in Cycle 15 provide clear evidence that contaminants and impurities

were allowed into the water during that period. The clear evidence of water chemistry anomalies and impurities, together with the timing of the discovery of nodule formations and accelerated corrosion soon after the water chemistry trends existed and with the previous absence of such corrosion problems, constitutes substantial circumstantial evidence that the water chemistry problems caused initiation of nodule formation and accelerated corrosion. It is concluded with high confidence that the impurities allowed into the water during that period caused initiation of nodule formation and accelerated corrosion.

Major Contributing Causes:

Condenser Leak - The condenser leak existed for a long period of time, roughly the last 17 months of Cycle 15 operation, and continues in Cycle 16 to the time of this writing. A condenser leak of this duration had not occurred previously in recent operating history (within the last 7 years at least). During this time, in combination with the degraded filter demineralizer performance, the condenser leak likely played a part in allowing damaging contaminants to enter the primary side. The leak is believed to have directly passed some potentially damaging contaminants into the condenser, which subsequently passed into the reactor, in part at least due to the degraded filter demineralizer performance, which then deposited on the fuel or caused a chemical change at the fuel surface which is responsible for the nodular corrosion and the accelerated corrosion observed. Even if, somehow, the damaging contaminant(s) did not directly pass through the condenser leak, the leak would still be implicated in the root cause since it has an effect on how the CFDs are managed and operated.
CAP-3 was created (Reduce or Eliminate Condenser Leak) to address this issue.

Degraded Filter Demineralizer Performance - A significant degradation in demineralizer performance was observed, beginning around June 2000, and continuing through the end of Cycle 15, including pronounced degradation in CFDs D and F during the period of most interest late in Cycle 15. During the period late in Cycle 15, pronounced trends in reactor water chemistry coincide with periods of pronounced degradation in CFD performance, especially for D and F. The pronounced degradation is evidenced by CFD effluent monitoring results and by the evidence in the water chemistry trends, and is explained by known problems with resin precoat following Septa changeouts in F in April of 2000 and D in November of 2000. Throughout the more extended period beginning in June of 2000, copper ratio drops (indicating a reduction in copper solubility), pH increases, and Na+ concentration is elevated in this time period. The main steam line monitor trends suggest that organic material may have been introduced over this time period. For these reasons, CAP-4 was created (Optimize Filter Demineralizer Performance). CFD performance has improved significantly since CAP-4 was written in May of 2002. Therefore, CAP-4 will be closed based on that evidence of improved performance and on completion of the independent reviews called for in the CAP. CAP-5 was created to assure that water chemistry will continue to be monitored for the negative indicators exhibited during the period of interest late in Cycle 15.

Minor Contributing Causes:

Fe & Zn Injection - In 1996, as part of a drywell ALARA dose reduction program, iron and zinc injection were initiated. Fe is injected for the purpose of forming stable metal oxides on the fuel surfaces, trapping cobalt and the associated activation product, Co-60 in stable spinel CRUD formations. Co-60 is the major contributor to drywell dose. Zinc is injected to help prevent the deposition of Co-60 on out of core surfaces, by competing directly with the Co for deposition at those sites. Based on the CRUD analysis, the total CRUD loading has generally increased from Cycle 12 to Cycle 15, the time frame during which Fe & Zn injection have been utilized for dose control. Over this time, an increase in the amount of CRUD deposited as a hard, stable, spinel type formation has been observed, relative to the amount of fluffy hematite CRUD deposited. The increases in Fe & Zn concentrations in the Feedwater and reactor initiated in 1996 for recirculation piping dose reduction and compliance with fuel vendor and EPRI guidance may also have played a role in the concentration of this unidentified substance in the subcooled boiling region of the core,

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which is where the peak oxide thicknesses have been measured. For this reason, CAP-1 was created (Implement Reduced Fe & Zn Targets), to properly balance the need for dose reduction vs. the potential for aggravating the fuel corrosion rates, thereby increasing the risk of fuel failure. Revised Fe and Zn targets were provided in April of 2002, and the investigation into the issue of what would be optimum targets for the long term and for after initiation of moderate Hydrogen Water Chemistry (HWC) is ongoing.

Presence of Copper - While the copper is not necessarily known to play a part in the nodule formation and/or the accelerated corrosion, it plays an important role in one of the prominent BWR failure mechanisms, CRUD Induced Localized Corrosion (CILC). CAP-2 was created (Perform Copper Reduction Conceptual Study), to examine possible alternatives for reducing or eliminating the levels of copper being introduced via the feedwater, the two most obvious alternatives being condenser tube replacement or deep bed demineralizer installation. CAP-2 was created with the original version of this PER Resolution. Based on root cause findings since then, and on experience at Browns Ferry as discussed in item 5 below, CAP-2 will be closed.

GENERIC IMPLICATIONS

This corrosion problem is specific to the fuel, since that is the only place where Zircaloy is used.

Fuel corrosion events at other BWR plants worldwide have been evaluated for similarities and applicability to CGS. The following five events were evaluated:

1) The corrosion event at Hamaoka Unit 1 in Japan in 1990 indicated certain similarities in the water chemistry changes leading to enhanced corrosion. This is one of the potential root causes CGS is pursuing, i.e., to improve water chemistry similar to Hamaoka to eliminate CGS corrosion problem. Also, the rod position effect identified at Hamaoka was observed at CGS.

2) In 1998, River Bend experienced seven fuel failures in Cycle 8 operation. In the EOC8 fuel inspection, it was determined the failures were caused by the thermally-induced accelerated corrosion due to heavy CRUD deposition. The iron input at River Bend as indicated by the CRUD analysis was very high (much higher than the level experienced at CGS). When the iron input was monitored closely at River Bend in the following cycle to ensure the levels were within the limits, the problem did not recur.

3) Vermont Yankee has experienced four fuel failures from December 2001 to March of 2001. An initial evaluation based on the number of failures in a relatively short period of time pointed to the tentative conclusion that the failures may be corrosion related. Vermont Yankee was shut down in May 2002 (moved their outage from fall 2002 to spring 2002) to remove and inspect the failed fuel. They replaced the four failed bundles and 40 additional bundles. While the root cause investigation is still progressing, it has been determined that the failures are CILC-type, and the fuel had heavy copper deposition of around 2000 microg/cm2.

4) The outage 2000 fuel inspection at KKB in Europe revealed indications of accelerated corrosion on lead use fuel rods with a pre-oxidized outer surface. Since CGS does not use pre-oxidized cladding, the experience at KKB should not have any bearing on the CGS corrosion observation being investigated.

5) Browns Ferry Unit 2 experienced four fuel failures from December 2001 to March of 2001. An initial evaluation based on the number of failures in a relatively short period of time pointed to the tentative conclusion that the failures may be corrosion related. Browns Ferry was shut down in a mid-cycle outage to remove and replace the failed fuel. They replaced only the four failed bundles. Soon after restart, they had indications of additional failures. Browns Ferry now has about 20 more failures, and is planning another outage to replace failed fuel. While the root cause investigation is still progressing, it has been determined that the failures are CILC-type. However, there are not heavy copper deposits on the fuel. The part normally

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played by copper oxide in the CILC failure process (formation of an oxide layer tightly adhering enough to cause steam blanketing) is apparently being played by some other compound.

RECOMMENDATIONS

To prevent future accelerated fuel corrosion it is imperative that condenser in-leakage be eliminated or minimized, and that the improvement in condensate filter demineralizer performance through improved maintenance, resin loading, and precoat changes already achieved be maintained. These actions will preclude a repeat occurrence of the conditions experienced late in Cycle 15. Reduction of the copper source term would represent added insurance that if nodule corrosion is present, the risk of CILC failures is reduced.

The list of recommendations and CAPs below will help achieve these preventative measures.

Corrective Action Assignments:

201-2842-01 -Implement Reduced Fe & Zn Targets. Implement the Fe and Zn guidelines provided to the plant for the reactor feedwater. These guidelines will minimize deposition of Fe rich spinels on the fuel, provide Co reduction for radiological safety, and provide compliance with the Fe/Zn ratio to prevent shadow corrosion. The appropriate procedure(s) should be changed to reflect these limits. Chemistry, Materials Engineering, and Reactor Engineering will jointly evaluate future changes to the target levels as necessary. Readiness for closure will be accomplished via email, from CAP Manager to Disposition Manager.

201-2842-02 - Perform Copper Reduction Conceptual Study. This CAP was created with the original (Rev. 0) version of this PER Resolution. Since copper is not directly implicated in the revised root cause documented in this revision of the PER Resolution, this CAP will be closed.

201-2842-03 - Reduce or Eliminate Condenser Leak. Continue with the condenser leak repair evaluation work. Independent review by outside an consultant has resulted in the identification of the proper tube plug material that will survive our existing CW chemistry and plugging applications. This CAP will be directly related to the Condenser Reliability Project, and will be finished when that project is completed. July of 2003 is selected as the deliverable date based on the assumption that the condenser leaks are repaired in R16, and evidence that the leak has been repaired is obtained during startup and initial Cycle 17 operation (closure via email documenting this from CAP Manager to Dispositioning Manager).

201-2842-04 - Optimize Filter Demineralizer Performance. An independent evaluation of our Condensate Filter Demineralizer has been completed. CFD performance has improved significantly since the period late in Cycle 15 when CFD bypass contributed directly to initiation of the fuel corrosion problem. Based on these facts, this CAP will be closed before the October 27 scheduled date.

201-2842-05 - Formalize Monitoring of Water Chemistry for Detection of Corrosion-initiating Conditions. This CAP is new with this revision of the PER Resolution, and serves the purpose of assuring continued avoidance of the Cycle 15 water chemistry problems in the future.

PTL Items:

PTL Item 193105: Monitor and Assess Expected NMCA Impacts. Continued monitoring of industry experience relative to fuel cladding corrosion impacts caused by NMCA application and loading. This information will be used to establish CGS application of NMCA and hydrogen injection levels to mitigate stress corrosion cracking. This PTL item will be assigned to the Fuel Corrosion Resolution Project.

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PTL Item 193106: Continue Fuel Surveillance Program. In addition to fuel inspections already planned for R16, maintain a fuel-monitoring program for future outages to continue to assess fuel corrosion performance, including impacts of our mitigation applications such as NMCA and Fe/Zn injection on the fuel cladding. In addition, the monitoring will allow the evaluation of new claddings being used in the fuel design and assessment of their performance at high burn-ups. This PTL item will be assigned to the Rx/Fuels Engineering organization.

PTL Item 193107: Improve Monitoring of Potential Chemistry Impacts on Fuel Performance. Develop appropriate monitoring tools and standards to help chemistry identify when the RPV chemistry may be potentially jeopardizing the fuel. These standards would include action levels to associate with specific levels, e.g. Fe/Zn ratios. This PTL item will be assigned to the Fuel Corrosion Resolution project. This PTL item will be coordinated with CAP 201-2842-05.

PTL Item 193108: Improve Routing of Fuel / Chemistry Related PERs. Assure that PER's associated with water chemistry are communicated to Reactor Engineering and Materials Engineering. This would allow better communication and identification of problems that may exist that one Group or the other are not aware of. This PTL item will be assigned to the Fuel Corrosion Resolution project.

PTL Item 193109: Complete CGS Fuel Corrosion Root Cause Evaluation. Complete all activities associated with the investigation, analysis, and root cause evaluation phases of the Fuel Corrosion Resolution project. One task currently ongoing is the investigation into the possibility that contaminants leading to the water chemistry trends and anomalies late in Cycle 15 could have been released from the fuel CRUD in some kind of CRUD destabilizing or restructuring event. This PTL item will be assigned to the Fuel Corrosion Resolution project.

PTL Item 193157: Reconsider Maneuvering Restrictions. Hold a meeting between the Fuel Corrosion Resolution project team and representatives from Reactor Engineering to discuss the appropriateness of continuing with the existing conservative operational measures in place (maneuvering restrictions), in light of the revised and improved understanding of fuel corrosion root cause. Their appropriateness for the remainder of Cycle 16 should be discussed, as well as for the upcoming Cycle 17. This PTL item will be assigned to the Fuel Corrosion Resolution project.

Other Recommendations Already Completed:

R-1.Select Appropriate Fuel Cladding. Maintain the use of Beta quenched cladding for the gadolinium rods until demonstrated that other cladding types will not be effected by CGS's water chemistry. This has already been done for the R16 reload batch. This will be reconsidered for the R17 batch based on experience gained in Cycle 16 and Cycle 17.

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REFERENCES

1) Letter, Richard Matheny (Westinghouse) to R.A. Vopalensky (EN), "Supporting Information for Startup of Cycle 16," Westinghouse Electric Company, WEN-01-036, dated June 14, 2001
2) Fuel Corrosion Root Cause Report (DRAFT), Energy Northwest, May 2002
3) Evaluation of SVEA-96 Fuel Performance in Columbia Generating Station Cycle 16, BTA-02-040, Westinghouse Atom AB

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Quality Assessments Initiated ☐ Yes

Followup Assessment of Operability ☐ Yes ☒ NA

Permanent Equipment Disposition Classifications
☐ Permanent Accept-As-Is ☐ Permanent Repair ☐ Rework ☒ NA

Equipment Classification: Quality Class: ☐ 1 ☐ A ☒ 2 ☐ G
☐ Safety Related ☐ ASME ☐ NA

Previous problems or generic impact discussed ☒ Yes ☐ NA

Significant: ☐ Yes ☒ No | Number of interim Corrective Actions: 0 | Number of permanent Corrective Actions: 11

Cause Determination Codes

☐ No Cause Necessary ☐ Unknown (UNKN), Justify in comments ☐ Assumed Risk (AR01), Justify in comments

DESCRIPTION	ORG	PROC	KEY	O&P	HE/IA	GEMS
Inappropriate Action: Plant downpower (60%) required to repair main condenser tube leak on-line resulted in a generation loss of approximately 18000 MWhrs	**MUL**	**FM1**	**FM**	**P-2**		

Comments:

Management Summary:

Event

On May 25, 2004, Operations manually reduced power to approximately 60% per OI-34 to support on-line main condenser tube plugging in accordance with PPM 8.3.312. Management decided to plug the main condenser tube leak because reactor water chemistry exceeded limits established in SWP-CHE-02 for protecting reactor vessel internals.

Problem

A condenser tube leak required a plant down power to repair the leak on line. This down power resulted in lost generation of approximately 18,000 MWhrs.

Conclusions

The physical cause of the tube leak is indeterminate pending results of the failure analysis for the leaking section of main condenser tube. The leaking tube section will be removed for failure analysis during refueling outage R-17. These actions are identified and tracked under Work Order (WO) 01073375. This cause determination provides a qualitative risk assessment for main condenser tube leaks resulting from foreign material in the CWS, identifies corrective actions to reduce these risks, and identifies fundamental causes for failure of foreign material exclusion controls and for failure of corrective actions from previous occurrences to prevent recurrence.

Root Causes

+ Widespread lack of regard for, or awareness of, importance for foreign material exclusion controls in the CWS across the organization indicating a lack of commitment to FME program implementation.
+ Ineffective corrective actions for previously identified foreign material problems.
+ Lack of appropriate foreign material controls in the CWS (i.e., widespread use of wire ties without regard to the consequence of their use).

Significance

The event had no adverse impact on nuclear safety. Reactor water chemistry guidelines remained within established limits. The online tube plugging effort involves work conditions that increase industrial safety risks for the duration of the task. Equipment and personnel performed as planned during the down power and tube plugging evolution. The event resulted in approximately 18,000 MWhrs loss generation. Main condenser tube leaks caused by flow induced fretting wear or erosion from debris in the condenser have occurred at least seven times in the past. In addition, foreign material in the CWS has created a condition of constant near misses. Debris that could cause main condenser tube leaks have been discovered in the

Approvals For Permanent Disposition

PER Dispositioner	*HUMMER, M*	*07/23/04*
Dispositioning Manager	*TWOMEY, JD*	*07/23/04*

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water boxes upon every entry since initial plant startup. At least 25 tubes were plugged during R12 because of accumulated damage to the inside diameter of tube from flow induced fretting or erosion from foreign material since initial plant startup. Statistical analysis of this occurrence history indicates an average of 509 days between main condenser tube leak events that requires plant shut down or down power for repairs (or a mean time between failure of 470 days).

Principal Corrective Actions

1. Eliminate the sources of foreign materials that are dominant contributors to risk of main condenser tube leaks.
2. Evaluate the need for physical barriers that provide effective protection against foreign material sources that cannot be reasonably eliminated. Based on results from this evaluation, implement additional and/or enhanced barriers to reduce the risk of tube leaks from foreign materials to acceptable levels.
3. Develop and implement strict program and administrative controls for foreign material exclusion from the CWS and main condenser water boxes.
4. Provide clear signage that communicates a strong message supporting foreign material exclusion controls at all locations (permanent and temporary) that present openings to the CWS and main condenser water boxes.
5. Communicate the consequences and significance of main condenser tube leaks especially those caused by foreign material in the CWS, the corrective actions taken, and roles and responsibilities of all personnel for preventing foreign material from entering the CWS.
6. Assign roles and responsibilities for developing and implementing appropriate practices to ensure foreign material discoveries in the CWS and main condenser capture reasonably available information.
7. Emphasize the expectation for using the condition reporting process to record foreign material discoveries when accessing main condenser water boxes. This is necessary to support subsequent assessment of the effectiveness of the foreign material exclusion controls and to implement appropriate corrective actions.
8. Assess the effectiveness of corrective actions to prevent recurrence during a CWS or refueling outage whichever occurs first.

Description of the Event (or Issue):

A. Time Line Sequence

On 5/19/04 at 03:51, with the reactor operating at 100% power, an increase in the reactor water sulfate level and main condenser hot well sulfate level was noticed. CR 2-04-02341 was generated to document this condition. The shift manager and STA were informed and follow-up sampling was performed. The main condenser leak was confirmed and calculated to be approximately 53 mL/min per CI-11.7 at 13:12.

Chemistry Management established decision points per PPM 1.3.67 at 15:30.

1. If the leak rate exceeds 150 mL/min, NDE should be contacted to perform SF6 testing to identify the leaking water box.
2. If the leak rate reaches 300 mL/min, plans should be made to downpower, find and repair the leak.

From 5/20/04 to 5/22/04 the leak rate trended upwards to about 160 mL/min. Preparations were being made by NDE to perform a SF6 test to establish the leaking water box. The test equipment was being delivered via FedEx because it was off site for repair and calibration. Preparations were also being made by maintenance and engineering to perform on-line tube plugging.

On 5/23/04 at 13:15 the leak rate reached 302 mL/min, exceeding decision point 2. The Shift Manager made a MANS notification due to the increased leak rate on 5/23/04 at 14:32.

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By 5/24/04 the leak rate had increased to about 418 mL/min, and NDE leak location testing had commenced. On 5/24/04 at 21:45 NDE determined the leak was in the "C" water box, and Chemistry had determined the leak rate to be about 431 mL/min.

The down power to 60% power was commenced on 5/25/04 at 00:55 and completed on 5/25/04 at 05:00. From that time until 5/26/04 at 02:36, the "C" water box was isolated, and the leaking tube was located and plugged.

From 5/26/04 02:36 to 5/26/04 11:27 the "C" water box was placed back on service and the ascension to 100% power was commenced. The reactor was returned to 100% power on 5/26/04 at 21:54. The leak did not return.

Attachment A provides the Detailed Timeline of Events for May 2004 Tube Leak.

B. Additional Background Information

Foreign material can enter Columbia's Circulating Water System (CWS) from a variety of sources as shown in the simplified system schematic of Figure 1. Foreign material of a critical size, shape, and hardness in the CWS flow can get caught at main condenser inlet tube sheets number 1 and 3 and cause a tube leak.

Features and conditions of Columbia's Circulating Water System that increase sensitivity to main condenser tube leaks caused by foreign material (i.e., differences between Columbia and other nuclear power plants) include:

+ Use of wire ties to secure fill in the cooling towers
+ Casual use of wire ties for a variety of tasks (where other methods might be more appropriate)
+ Demineralizers with lower leak handling capacity than those plants with deep bed demineralizers
+ Use of closed loop cooling system, which recirculates the debris (not a once through design)
+ Inability to back flush the condenser
+ Lack of a comprehensive FME implementation in the circulating water basin and cooling tower areas
+ Admiralty Brass and 70-30 Copper Nickel alloy tubing (i.e., softer than most other materials and therefore less resistant to abrasion/erosion)

Types of foreign material historically discovered in the waterside of the Circulating Water System are listed below by relative frequency of observation. The qualitative likelihood of these foreign materials causing a main condenser tube leak is indicated in parenthesis. Likelihood is a subjective estimate based on previous main condenser tube leak occurrences, previously observed damage, and the critical size, shape, and hardness of the foreign material.

+ Tumbleweeds (minor)
+ Duct tape (minor)
+ Boundary tape (minor)
+ Pieces of ceramic fill (moderate)
+ Tower Fill clips (moderate)
+ Tower Keepers T's (two piece part) (moderate)
+ Wire tie pieces - Typically clipped (severe)
+ Wire ties (unused) (severe)
+ Tower Drain (Spray?) nozzles (minor)
+ Metal Wire - Light gauge sizes (severe)
+ Scaffolding Wire (moderate)

+ Animal bones (birds/rabbits) (minor)
+ Foam chinking (minor)
+ Various types of plastic bags (minor)
+ Paper trash (minor)
+ Pieces of gaskets (minor)
+ Duck or waterfowl bill (minor)
+ Sand and gravel (minor)
+ Ball peen hammer (minor)
+ Flashlight (minor)
+ Tape measure (minor)

Figure 1 Circulating Water System Simplified Diagram Indicating Foreign Material Sources (see hard copy).

Extent of Condition

A. Scope

The extent of condition evaluation considers other similar components that might experience tube leaks due to damage from debris and would require a plant downpower or shutdown for repair. Assessing the potential for foreign material damage to rotating equipment, major electrical equipment, or instrumentation and control equipment is outside the scope of this root cause analysis. PER 203-2050 (see PERAs 203-2050-02 and -07) involve performing a current assessment of and implementing appropriate enhancements to Columbia's overall foreign material exclusion controls. Other plant components that have internal tube bundles include the feedwater heaters (FWHs), moisture separator reheaters (MSRs) and numerous heat exchangers. Further evaluation of these components is outside the scope of this root cause analysis for the following reasons.

1. The MSRs and FHWs as these components route "closed" systems (COND, MS, BS, etc.) through their tubes as opposed to the condenser that uses an "open" system (CW).
2. When maintenance activities are being performed inside these components foreign material exclusion (FME) is maintained per our site procedures.
3. Historical data that reveals damage to these components from foreign material has been limited to 1-2 tubes in a feedwater heater from a bolt.
4. A tube leak in any heat exchanger does not have the same potential consequences (damage to vessel internals) as a tube leak in the main condenser due to the chemistry in the circulating water system.

The scope of this root cause analysis is also limited to tube leaks caused by fretting wear or erosion from debris on the water side of the condenser. Assessing the potential for damage to main condenser tubes from other mechanisms that could result in a tube leak and require a plant down power or shutdown for repair is outside the scope of this root cause analysis for the following reasons.

1. The cause of the damage to the condenser tube and resulting leak is most likely due to debris induced fretting or localized flow erosion of the tube in the condenser waterbox.
2. Damage due to steam impingement usually occurs quickly once the tube is exposed to the steam and is limited to outer or peripheral tubes where the condenser penetrations are located. There were no known steam leaks into the condenser at the time as detected by thermal performance evaluation before and during the time period when the condenser leak was identified. The leaking tube was not a peripheral tube that could have been exposed to steam erosion. The tube was located near the center of the tube bundle (C1 top tube sheet, upper right quadrant Row 24 tube 4).
3. Tube damage due to long-term flow induced erosion has different characteristics than that of debris induced fretting or debris induced short-term localized erosion. Long-term flow induced erosion is addressed by eddy current testing performed on the condenser tubes during refueling outages.

4. Damage to main condenser tubes due to steam impingement was recently evaluated (including extent of condition) under PER 203-1439.

Therefore, the scope of condition examined by this root cause analysis does not address tube leaks caused by steam impingement or long term flow induced erosion or other service related tube damage such as dezincification and stress corrosion cracking. This root cause analysis focuses on the leaks caused by localized erosion or fretting wear from debris on the water side of the condenser. The extent of condition evaluation is limited to the main condenser, COND-HX-9.

B. Vulnerability

Circulating Water (CW) system flows through inlet and outlet tube bundles in the main condenser. The flow enters the tube bundles at sheets 1 and 3 and exits at sheets 2 and 4 (see Figure 1). The direction of the flow tends to trap debris on tube sheets 1 and 3 while pulling debris off of tube sheets 2 and 4. Thus, the vulnerable locations are at main condenser tube sheets 1 and 3. Past experience indicates that foreign material of critical size, shape and hardness for causing a tube leak due to debris induced fretting or erosion are equally likely to get trapped at any of the tubes at tube sheets 1 and 3. The total number of tubes in the main condenser is 48636 of which 1896 have been plugged in the past. Thus, the total number of main condenser tubes vulnerable to debris induced fretting or localized flow erosion is 46740. Damage to any of these tubes can result in a CW leakage into the Condensate system that adversely impacts reactor water chemistry.

Personnel observing main condenser tube sheet conditions during outages or down power conditions, always observe foreign material trapped at the number 1 and number 3 tube sheets. The types of foreign material and relative frequency of discovery are indicated in the Event Description Section. Debris that could cause main condenser tube leaks have been discovered in the water boxes upon every entry since initial plant startup creating a condition of continuous near misses. At least 25 tubes were plugged during R12 because of tube wall wear from flow induced fretting or erosion due to foreign material. Main condenser tube leaks caused by damage from foreign material in the CWS that require plant shutdown or down power to perform repairs includes at least seven occurrences over a period of eight and half years. The average time to the next occurrence is 509 days and the median time to next occurrence is 461 days. This history of prior occurrences is plotted in Figure 2. A three-parameter Weibull plot of these prior occurrences is shown in Figure 3 and indicates a mean time between failures of 470 days.

Figure 2, Days Between Tube Leaks From Foreign Material in CWS (see hard copy).
Figure 3, Main Condenser Tubes Reliability Vs. Days Since Last Tube Repair (see hard copy).

Statistical analysis of the historical occurrences shown in Figure 2 provides a means for estimating the expected reliability of the main condenser tubes as a function of time since last tube repair within associated uncertainty. These results provided in Figure 3 show the expected reliability of continued service without experiencing a tube leak that would require shut down or down power for repairs. The expected reliability decreases from approximately 96% at 130 days of service (with 90% confidence interval from between 100% and 76% reliability) to about 56% at 400 days of service (with 90% confidence interval from between 78% to 28% reliability).

C. Actions Taken

The leaking tube was plugged and RCS chemistry returned to nominal conditions to support 100% power operations. No other actions were taken to address the condition in response to this event. Numerous actions have been taken in response to previous tube leak events and in response to repeated documentation of foreign material in the main condenser water boxes. However, none of these previous

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actions effectively address vulnerability of main condenser tubes to similar damage because they do not identify or prescribe remedies for causes of the foreign material or causes of ineffective foreign material controls or causes of problems and issues with existing barriers (screens) that allow foreign material bypass. Specific Problem Evaluation Request (PER) records identified and reviewed are included in Attachment C.

Analysis

The physical cause is indeterminate pending results from failure analysis of the leaking section of main condenser tube. The leaking tube section will be removed for failure analysis during refueling outage R-17. These actions are identified and tracked under Work Order (WO) 01073375. This cause determination provides a qualitative risk assessment for main condenser tube leaks due to debris induced fretting or localized flow erosion and identifies corrective actions to reduce these risks. The analysis also identifies fundamental causes for failure of foreign material exclusion controls and for failure of corrective actions from previous occurrences to prevent recurrence.

A. Cause Determination Techniques

Cause determination uses the following methods.

1. Cause and effect analysis diagram identifies the actions and conditions that are necessary and sufficient for an unplanned power reduction to repair a main condenser tube leak. Attachment E provides the detailed cause and effect diagram.
2. Difference analysis identifies characteristics, features, or conditions at Columbia that differ from other plants in the industry and influence Columbia's sensitivity to main condenser tube leaks. This is provided in Section 2 under Additional Background Information.
3. Barrier analysis identifies the physical, programmatic, and administrative means (i.e., barriers) for excluding foreign material or for preventing foreign material from reaching the main condenser tube sheet area, assesses their effectiveness, and identifies flaws or conflicts that compromise these barriers. This is presented as part of the Failure Mode Effects and Criticality Analysis (see Attachment F).
4. Failure Mode Effects and Criticality Analysis is used to identify ways main condenser tubes can develop a leak, the consequences of these leaks, and their relative significance (i.e., a risk analysis). This analysis is presented in Attachment F.

B. Problems Identified During Evaluation

The design, maintenance, and operating environment conditions of the circulating water system, cooling tower, and main condenser make it susceptible to foreign material problems. Previous operating experience provides compelling evidence of these susceptibilities. Despite the history of incidents that demonstrate these susceptibilities, appropriate and effective foreign material exclusion controls have not been consistently applied to the entire system.

C. Equipment Failure Analysis

The leaking main condenser tube was located and plugged during the unplanned power reduction and will be removed during refueling outage R 17 for failure analysis of the leak location. This effort is tracked under Work Order (WO) 01073375.

D. Human Error Analysis

Despite prior similar occurrences of main condenser tube leaks due to foreign material in the Circulating Water System at Columbia and at other plants in the industry, Columbia personnel demonstrated lack of

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awareness or sensitivity to potential consequences of foreign material in the Circulating Water System. The failure to recognize and respond to the need for appropriate foreign material exclusion controls for this system reflects human errors of misjudgment. As a result, these susceptibilities have not been effectively managed, indicating management control weakness and continued program deficiency in failure to apply suitable foreign material exclusion controls for the entire Circulating Water System. Corrective actions for the previous occurrences treated symptoms or suspected / potential causes. Corrective actions targeted at establishing an appropriate and effective means of foreign material exclusion for the Circulating Water System have been delayed, cancelled, deferred, or transferred to other PERs and are still pending. This condition indicates corrective action program ineffectiveness. The corrective action program requirements for performing root cause analysis were not followed for all the previous events and condition when appropriate (i.e., PER 298-0180 and PER 204-0288 met the criteria for root cause analysis but the PER database provides no record of performing a root cause analysis). This condition involves human errors of failure to take actions prescribed by, to meet the intent of, and demonstrate strict adherence with SWP-CAP-01. As a result, the causal analysis was not always performed at the appropriate level and this reduces the likelihood for identifying the fundamental causes and for taking corrective actions that provide effective means for foreign material exclusion for the Circulating Water System. This shows faulty decision-making on the appropriate resolution category for PER 204-0288 and failure to provide documentation of root cause analysis for PER 298-0180. Both indicate weakness in the corrective action program to ensure applicable program requirements are satisfied and supported by documentation.

E. Findings and Conclusions

1. Principal Findings and Conclusions, Significance, and Contribution to Event

+ The main condenser is susceptible to tube leaks caused by foreign material.
+ Foreign material in the CWS has been a long-standing issue.
+ Foreign material exclusion controls have not been effectively applied to the entire system.
+ Corrective actions intended to establish an appropriate and effective means of foreign material exclusion for the CWS have not come to fruition because they have been delayed, cancelled, deferred or transferred to other PERs and are still pending.
+ Previous similar events and reports of inadequate foreign material controls for the CWS have been resolved at the Evaluate Only or Apparent Cause Evaluation level of significance. Events that required a plant shutdown or down power to repair a main condenser tube leak or that describe an adverse trend known of an adverse condition that historically has repeatedly caused loss generation satisfied the criteria (existing at the time) for performing a root cause analysis. Records in the PER database fail to document that a root cause analysis level of resolution was assigned and performed in all cases when the conditions satisfied program criteria for root cause analysis described in SWP-CAP-01. These conditions indicate weaknesses in applying corrective action program requirements and documentation that demonstrates compliance.

2. Discussion of Cause and Effect Relationships

The direct cause of the unplanned power reduction is the main condenser tube leak, an equipment failure. The main condenser tube leak appears to be the result of fretting wear or localized erosion on the inside diameter from foreign material of a critical size, shape, and hardness caught at the tube sheet. The most probable (i.e., only reasonable) source of foreign material in the waterside of main condenser is from the Circulating Water System. Foreign material in this system (including items of critical size, shape, and hardness) has been a long-standing issue as evidenced by continued discovery of foreign material, including items that have caused previous main condenser tube leaks. The design, maintenance, and operating environment conditions of the circulating water system, cooling tower, and main condenser make it susceptible to foreign material problems. Previous operating experience provides compelling evidence of these susceptibilities. The analysis identifies that wire ties and tie-wraps, wire and cooling tower parts have the greatest potential for causing a main condenser tube leak. The absence of ligament damage in this event

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indicates the potential that the foreign material was other than a tie wrap. There have been at least seven similar failures in the last eight and a half years, yet foreign materials that can cause main condenser tube leaks continue to be discovered in the CWS. Barriers to prevent foreign materials from reaching the main condenser tube sheet, including screens and foreign material exclusion administrative controls are not reliable. Despite the history of incidents that demonstrate these susceptibilities, foreign material exclusion controls have not been effectively applied to the entire system. Previous corrective actions have not been effective because they did not address the fundamental causes. None of these previous actions effectively address vulnerability of main condenser tubes to similar damage because they do not identify or prescribe remedies for causes of the foreign material or causes of ineffective foreign material controls or causes of breakdowns in existing barriers (screens). **The level of rigor assigned for these cause determinations did not always satisfy procedural requirements of SWP-CAP-01.** The level of cause determination assigned to previously reported problems was not at the root cause analysis level for all those events in which the criteria for performing a root cause analysis identified in the governing procedural requirements of SWP-CAP-01 was satisfied. Personnel did not demonstrate strict adherence to procedural requirements.

Causes and Contributing Causes

A. Root Causes

+ Widespread lack of regard for, or awareness of importance for, foreign material exclusion controls in the CWS across the organization indicating a lack of commitment to FME program implementation.
+ Ineffective corrective actions for previously identified foreign material problems.
+ Lack of appropriate foreign material controls in the CWS (i.e., The Level of FME control, Level D, is not commensurate with the level of FME control actually needed).

B. Significant Contributing Causes

+ Failure to demonstrate strict adherence to procedural guidance specified in PPM 10.1.13 for foreign material controls regarding housekeeping and cleanliness in and around the CWS where foreign materials can reasonably spread and enter design openings in the CWS.
+ Failure to demonstrate strict adherence to procedural guidance specified in PPM 1.3.62 for use of tie wraps commonly used at CGS.
+ Failure to demonstrate strict adherence to procedural guidance specified SWP-CAP-01 and apply criteria for performing root cause analysis when conditions warrant for previous reported events and conditions.

C. Other Contributing Causes

+ Original CW basin screen design provided a less than adequate barrier and the cleaning and seating practices previously used allowed foreign materials to bypass these screens.
+ Numerous work activities (routine and otherwise) that create opportunities for foreign materials to enter the CWS, especially when the need for appropriate FME controls are not recognized and planned into the work.
+ The risk posed to reliable plant operations by foreign material conditions that were known to exist was not performed because there is no requirement or guidance for doing so and thus, appropriate levels of management may not have recognized the actual risk.
+ Foreign material discovery documentation (including suitable level of detail and supporting evidence to support subsequent causal analysis and significance determination) were not consistently recorded because there is no requirement or guidance for doing so and thus, the extent of the condition and its significance may not have been recognized by appropriate levels of management.
+ WO 01067981 to drain and inspect the CW basin was last performed during R-11 under WO 00WE40, and has been deferred since.

D. Cause Codes

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Root Causes:
+ The lack of commitment to program implementation (OP-1).
+ Ineffective corrective action.
+ Lack of FME controls (P-2).

Significant Contributing Causes:
+ Failure to demonstrate strict adherence and compliance with applicable procedure requirements.

Other Contributing Causes:
+ Original design weakness (OD)
+ Work activities that create FME issues (PP-1).
+ Not recognizing and responding the significant risk posed by FME deficiencies (P-2).
+ Not recording sufficient level of detail information regarding foreign material conditions discovered in a consistent manner (P-1).
+ Repeated deferral of important work (O-3).

Significance

A. Safety
+ Safety significance associated with this event is minimal because all safety equipment remained available and operated as designed during the down power and tube plugging.
+ The event had no adverse impact on reactor fuel, reactor vessel internals, or control blades because reactor water chemistry was monitored and maintained within chemistry guidelines (no reactor water chemistry guidelines were exceeded).
+ No safety concerns regarding human performance were identified during the event as the down power was conducted in an orderly fashion as planned.
+ The evolution of identifying and plugging main condenser tube leaks poses significant personnel safety risk because the only protection between the inspectors and the operating circulating water system is butterfly valve. In addition, the work is performed in a high radiation area under extremely difficult environmental conditions (heat and humidity).

B. Cost
+ This event resulted in a plant down power to approximately 60%. The down power lasted for approximately 41 hours that resulted in a generation loss of approximately 18,000 MWhrs.

C. Regulatory
+ No impact.

D. Mitigating Conditions
+ There does not appear to be any other damage to the condenser than at the tube that was plugged based on limited inspection of the condenser during tube plugging activities.
+ Other foreign materials at the main condenser tube sheets did not settle in a critical location for sufficient duration to cause a tube leak.

E. Frequency of Occurrence
+ Main condenser tube leaks caused by flow induced fretting wear or erosion from debris in the condenser have occurred at least seven times in the past. Foreign material in the CWS has created a condition of constant near misses. Debris that could cause main condenser tube leaks has been discovered in the water boxes upon every entry since initial plant startup. During R12, the accumulated impact of flow induced fretting or erosion caused by foreign materials during the previous years was discovered to be extensive enough to warrant plugging at least 25 tubes. The average time to the next occurrence is 509 days, the median time to next occurrence is 461 days, and the mean time between failures is 470 days.

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Precursors

A. Internal Operating Experience

The PTL database is the information source for this internal experience review. This review identifies records of events involving main condenser tube leaks (i.e., events similar to those described in PER 204-0811). The PTL database was searched for records that contain keywords: "tube leak, fretting, foreign material, flow induced." Of the 274 PERs identified from the PTL database, twelve were relevant to foreign material in the main condenser. Attachment C provides detail evaluation of these twelve relevant PERs.

The attempts to address the source of the foreign material were reseating and cleaning the CW screens, and replacing the Cooling Tower fill tie wraps. The tie wrap replacement is scheduled for R-17 (reference Work Order 01059945 and PERA 203-1497-01), so the effectiveness of this corrective action cannot yet be determined. The cleaning and adjusting of the CW screens has not been effective since components that are from the cooling towers which are too large to fit through the screens and are not originally present in the waterboxes, are still being found in the condenser. The source of foreign material and its mitigation once entering the CW system has not been adequately addressed. Recommendations are included in the Corrective Action Plan.

B. External Operating Experience

The INPO website SEE-IN Library database is the information source for this external experience review. This review identifies records of events involving main condenser tube leaks (i.e., events similar to those described in PER 204-0811). The INPO SEE-IN Library database was searched for records that contain keywords: "condenser near tube leak" or "condenser near foreign near material." Over 140 records from the SEE-IN Library database satisfied the search criteria. Review of these records identified 20 events relevant to main condenser tube leaks or degradation from foreign material. Attachment D provides the detailed evaluation of the 20 relevant industry event records. It is considered highly likely that similar events in the industry may not be reported to the INPO network because these events are not considered nuclear safety significant and may not satisfy established reporting criteria.

The 20 relevant industry event records included 16 events that involved main condenser tube leaks. Only one of the INPO operating experience records (OE17243 dated November 7, 2003) identified a main condenser tube leak resulting from foreign material on the waterside of the main condenser. The plant involved repaired the condition however; the record does not identify any actions to address the causes. Main condenser tube leaks from various causes is an ongoing concern as evidenced by the industry operating experience records. **The records indicate most main condenser tube leak events are caused by dumping steam to the condenser, tube plug issues, or protective coating issues.** The INPO operating experience records do not provide insights for potential improvements to eliminate or reduce the likelihood of foreign material on the waterside from causing main condenser tube leaks. Recommendations are included in the Corrective Action Plan.

C. Previous Corrective Action Effectiveness

+ Internal operating experience identifies numerous actions taken in response to previous tube leak events and in response to repeated documentation of foreign material in the main condenser water boxes. However, none of these previous actions effectively address vulnerability of main condenser tubes to similar damage because they do not identify or prescribe remedies for causes of the foreign material or causes of ineffective foreign material controls or causes of breakdowns in existing barriers (screens).
+ External operating experience review identified that Columbia reviewed INPO OE17243 and determined it was for information only. The external experience review documentation does not identify any actions that CGS has taken in response to external operating experience regarding prevent similar events.

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Extent of Cause

A. Scope
The extent of cause considers and evaluates conceivable sources of introducing foreign materials into the CWS and main condenser water boxes as indicated in the spreadsheet that presents the FMECA / Risk Assessment results in Attachment F.

B. Vulnerability
Vulnerability is also indicated in the spreadsheet that presents the FMECA / Risk Assessment results in Attachment F in the form of relative risk ranking.

C. Actions Taken
Actions are included in the overall corrective action plan below

Corrective Action Plan

A. Corrective Actions To Prevent Recurrence
1. Establish a focus team to evaluate the need for physical barriers to provide effective protection against foreign material sources that cannot be reasonably eliminated. Based on results from this evaluation, implement additional and/or enhanced barriers to reduce the risk of tube leaks from foreign materials to acceptable levels. This is a CAPR that contributes to addressing the third root cause.
2. Develop and implement strict program and administrative controls for foreign material exclusion from the CWS and main condenser water boxes. This program should specifically address controls for the circulating water pump house and cooling tower area and may require eliminating the sources of foreign materials that are dominant contributors to risk of main condenser tube leaks. This is a CAPR that contributes to addressing the first root cause.
3. Provide clear signage that communicates a strong message supporting foreign material exclusion controls at all locations (permanent and temporary) that present openings to the CWS and main condenser water boxes. For example, install appropriate signs at the entrance to the CW Pumphouse and the stairs for the cooling towers emphasizing the need for foreign material control. This is a CAPR that contributes to addressing the first and third root cause.
4. Communicate the consequences and significance of main condenser tube leaks especially those caused by foreign material in the CWS, the corrective actions taken, and roles and responsibilities of all personnel for preventing foreign material from entering the CWS. This is a CAPR that contributes to addressing the first root cause.
5. Assess the effectiveness of corrective actions to prevent recurrence during a CWS or refueling outage, whichever occurs first.

B. Corrective Actions In Place
+ Replace all tie wraps on the Cooling Tower fill with stainless steel wire during R17 (reference Work Order 01059945 and PERA 203-1497-01).
+ Drain and inspect the CW basin during R17 (reference Work Order 01067981).
+ The corrective action program and associated process for reporting conditions and problems, reviewing these reports, and assigning resolution category changed substantially in February 2004. The fact that this event is evaluated at the root cause level of significance demonstrates the current corrective action program follows and implements the criteria for root cause analysis (currently specified in SWP-CAP-06). The same conditions (pressures) as previous similar incidents existed for this event, however the decision-making process correctly applied the criteria and designated this event be resolved at the root cause level.

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Non-conservative interpretation of the criteria and cost benefit considerations from precedents set by previous similar events were argued. However, in this event, under the current corrective action program, the decision-making bodies applied the criteria as intended, demonstrated conservative decision-making, and designated the resolution category as root cause analysis. This result provides evidence that the root cause of failure to apply criteria for root cause analysis has been resolved by recent changes to the corrective action program and associated review process. This action (completed) addresses the second root cause.

C. Other Recommendations

1. Assign roles and responsibilities for developing and implementing appropriate practices to ensure foreign material discoveries in the CWS and main condenser capture reasonably available information.
2. Emphasize the expectation for using the condition reporting process to record foreign material discoveries when accessing main condenser water boxes. This is necessary to support subsequent assessment of the effectiveness of the foreign material exclusion controls and to implement appropriate corrective actions.
3. Perform remote visual examination of intake screens during circulating water system shutdowns like that currently performed on the TSW screens in the spray pond on a regularly scheduled basis.
4. Reinstall cover(s) that have been removed from over circulating water pump house basin.
5. Capture LIS survey responses regarding industry experiences with condenser tube leaks.
6. Communicate results and insights from this RCA to the newly formed FME coordinator position.
7. Ensure appropriate controls are in place to maintain the practice of not pulling the screens to clean them without first making sure that debris will not flow past the screen area in the process.

Team Members and Technical Contributors

A. Team Members
John Twomey, Disposition Manager
Matt Hummer, Dispositioner
Larry Syverson, MP&Q - NDE
Tim Mitts, Root Cause Analyst

B. Technical Contributors
Art Wood, Senior Engineer -- Condenser Subject Matter Expert
Carlos Leon, Planner I - Formerly PER Coordinator
Joe Flood, MP&Q - NDE

References

A. PTL and PER Databases

B. INPO Website SEE-IN Library Database

C. Focused Area Assessment Report - Foreign Material Exclusion Program (FME), Dated July 12 - 14, 2004.

Attachments (see hard copy)

A. Detailed Timeline of Events for May '04 Tube Leak

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B. Historical Foreign Material Finds and Resulting Damage

C. Internal Experience Review

D. External Experience Review

E. Cause and Effect Analysis

F. Failure Modes, Effects, and Criticality Analysis (Risk Analysis)

G. Wire Tie Damage Mechanism

DIC 1803.5

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CORRECTIVE ACTION PLAN
PERMANENT Corrective Action

PER No. 204-0811

ACTION NO	RESPONSIBLE NAME	MAIL DROP	ORG	SCHEDULED	RXSU	FAO RELATED
1	Individual HUMMER, MM	PE24	24510	10/30/04	☐ FORCED	☐
REV. NO: 0	Manager TWOMEY, JD	909S	24510		☐ REFUEL	
					☒ NO	

Corrective Action Description: (If Corrective Action is a Work Order, does the work order need only Approval ☐ or Completion ☐ to close the action)

Establish a focus team to evaluate potential physical barriers to provide effective protection against foreign material sources that cannot be eliminated. This focus team should include as a minimum representatives from System and Technical Engineering, Maintenance and C&MS. Focus team should review responses to LIS survey initiated by ENW regarding condenser leaks for industry experience related to foreign material barriers in cooling water systems. Based on the findings of this team additional CAPs should be initiated to track the team's recommendations as necessary.

APPROVALS FOR CORRECTIVE ACTION

Corrective Action addresses PER: Cause ☐ _____ Generic Impact ☐ N/A ☐

Close Interim Corrective Action #: upon completion of this Corrective Action.

Approval for assignment by Dispositioning Manager: *TWOMEY, JD* *07/23/04*

Corrective Action Comments:

11/1/04 closed. (smt)

Focus team was established and met on 10/26/04. Focus team was made up of representatives from Maintenance, Operations and C&MS as well as the system engineer and the FME coordinator. Team will meet on a bi-weekly frequency until satisfied that potential barriers have been identified and evaluated. CAP 06 has been initiated to document that potential barriers already identified by the team for consideration and to document the evaluation of these barriers and any other subsequently identified by the team.

This CAP may be closed with CAP 06 generated to track the team's recommendations (as per the description for this CAP).

Approval for closure by Dispositioning Manager: *TWOMEY, JD* *10/29/04*

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Condition Report

CR #: 2-06-02382

Creator: **LASALLE, JOHN R** Extension: **4613** Org. Code: **24870** Date/Time: **03/30/2006 / 09:02**

Facility: **Columbia Generating Station**

Primary Area This Issue Impacts: **Industrial Safety Related**
Secondary Area(s) This Issue Impacts: **Industrial Safety Related**

Do You Believe This Issue Affects The Operations Of This Facility or is Reportable: **NO**
Do You Believe This Issue is: **Significant**

- [ ] Operability
- [ ] Reportability Requirement:

Comments / Assessment:

- [x] Not An Equipment Issue
- [ ] The Equipment Part Number (EPN) Is:
- [ ] I Don't Know The EPN, Short Description:
- [ ] I Don't Know

Safety Related: YES [ ] NO [x]

Condition Summary Statement:
The condenser inlet end upper water box manway cover does not open completely due the interference with the air removal valves.

Detailed Description:
This condition adds to the difficulty in entering and exiting the water boxes for the A,B and C trains. If a person was to go down in the water box it is not clear how the person would safely be extracted. Several requests were made to remove the upper manway covers and were denied by outage management. The explanation for not removing the cover is that the manway could not be quickly replaced in a "potential" flooding incident. however, it was not clearly communicated how a "potential" flooding incident is reconciled against worker safety.

Any Actions That Have Been Taken To Address This Issue:

Category Determination:
- [ ] CAT A - Root Cause
- [ ] CAT B - Apparent Cause
- [x] CAT C - Minor Condition
- [ ] CAT D - No Further Action Req. (Explain Below)

Minor Condition Assign. **PTL**

PER Assignment: PER Number:
Disp. Manager: Org.:
Dispositioner:

CAT C Assignment: PTL Number: **A 242090**
Responsible Manager: **HOGUE, RW** Org.: **50500**
Responsible Individual: **EHR, RL** Org.: **50500**
Scheduled Completion Date: **04/13/06**

Operations Comments:

Immediate OPS Review By: _____ Date/Time: /

Reviewer Comments:

Reactor Startup:
Outage (Year):

Review Completed By: **CARLYLE, AG** Date/Time: **04/03/06 / 13:38**

Codes: **I/ENG LL SAFET CONDENSER D/OUT CRGED**

DIC 1803.5

ENERGY NORTHWEST
People · Vision · Solutions

PROBLEM EVALUATION REQUEST

PER No. 204-0811

System Number	MEL EPN	Discovery Date / Time
	COND-HX-9	05/25/04 10:21

Plant Downpower to Repair a Main Condenser Tube Leak

Problem:

Created From CR: 2-04-02506
Facility: Columbia Generating Station

Description of Condition: The plant has been required to reduce power to 60% to repair the main condenser on line. The downpower will cause significant loss of power production.

Initial Operability Assessment: (OPERABILITY) - Operability is NA. This CR documents the plant downpower to repair a condenser tube leak.

Immediate Corrective Actions Taken: This CR documents the plant downpower and will faciltate performing a root cause analysis

Originator Name / Mail Drop or Extension	Reviewer / Date - Time	Quality Identified	Response Required
ROCKEY, HERBERT D 4543	PRITCHARD, LA 05/26/04 11:51	YES ☐ NO ☒	☐ Evaluation Number _____

Originator Signature / Date
Signed: YES ☒ NO ☐ 05/26/04

Reviewer Comments
COND-HX-9 is ce 1 (NSR)
Humphreys/Inserra

SWP-CAP-06 Attachment 7.2 Costs - Root Cause Criteria E1 - Any condition or event that results in an unplanned loss of generation greater than 10,000 MW hr. (Approx. 20% reduction for 40?50hrs)

OPERATIONS REVIEWER

OPERABILITY DETERMINATION

Component:	System/Structure:		REPORTABILITY
☐ Operable ☐ Operable but degraded or non-conforming ☐ Not Operable ☒ N/A	☐ Operable ☐ Operable but degraded or non-conforming ☐ Not Operable ☒ N/A	☐ YES Perform Followup Assessment of Operability per 1.3.66 ☒ NO Assigned To: _____	☒ Non Reportable ☐ Potentially Reportable ☐ Reportable Requirement: _____ ☐ Potential Tech. Spec. Violation

Comments:
This CR requires no immediate actions and raises no operability or reportability issues.

Operations Reviewer Signature / Date / Time
MUTH, JJ 05/26/04 16:22

ASSIGNMENT

Resolution Categories	Cause Determination	Reactor Startup	Significant PER
☒ (A) Resolve Deficiency using PER Resolution Form ☐ (B) Trend ☐ Human Performance Related ☐ Generic Considerations	☒ Root Cause ☐ Apparent Cause ☐ Evaluate Only	☐ Forced ☐ Refueling Year ☒ No	☐ YES ☒ NO (Justify below)

Comments:
re-assigned to Twomey / Hummer on 06/08/2004 by TE Alton per PJ Inserra.

Assigned Dispositioning Manager	Dispositioning Organization
TWOMEY, JD	ENGINEERING
Assigned Dispositioner	**PER Program Reviewer Signature / Date**
HUMMER, MM	ALTON, TE 06/08/04

PER CLOSURE

PER Coordinator (Print) / Signature / Date	Transmitted To Plant Files (Print) / Signature / Date

Advance Copy

ENERGY NORTHWEST

Sudesh K. Gambhir
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October 23, 2008

Mr. Andrew J. Rapacz, M/D 1399
Manager Contract Generating Resources
Bonneville Power Administration
U.S. Department of Energy
c/o Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

Dear Mr. Rapacz:

Subject: **ENERGY NORTHWEST RFP 651803**
MAIN CONDENSER REPLACEMENT MODULES

Energy Northwest intends to execute a Contract as a result of RFP 651803 with Thermal Engineering International (TEI) in the not-to-exceed amount of $37,000,000. The contract will be for the design, manufacture and delivery of twelve condenser modules to replace the existing modules at the Columbia Generating Station. Details of the aforementioned transaction are contained in the attached Findings of Fact.

This contract action is subject to the right of the Administrator, Bonneville Power Administration, to disapprove pursuant to the Project Agreement.

Respectfully,

S.K. Gambhir
Vice President, Technical Services

/wge

Attachment

FINDINGS OF FACT

COLUMBIA GENERATING STATION RFP 651803

MAIN CONDENSER REPLACEMENT MODULES

SCOPE

This scope of work is for the analysis, design, manufacture, and delivery of replacement condenser modular bundles, and all other requirements in accordance with Procurement Specification 12502. In addition, the Supplier shall coordinate work with Energy Northwest and Energy Northwest's Installation Contractor(s) performing the project management, engineering and installation of the condenser modular bundles at the Columbia Generating Station.

BACKGROUND

The Columbia Generating Station Main Condenser Replacement Project has been broken into two principal segments: (1) the Design, Fabrication, and Delivery to the project site of Replacement Condenser Modules; and (2) Contract(s) for the performance of tasks necessary for the removal of the existing condenser modules and installation of the new replacement condenser modules.

RFP 651803, using the competitive negotiation process was issued on May 23, 2008, requesting proposals for the design, fabrication and delivery of replacement condenser modules. Responsive proposals were received on August 6, 2008, from the following three vendors: Westinghouse (Toshiba), Yuba Heat Transfer, and Thermal Engineering International (TEI). Following vendor discussions and plant site visits with all three proposers, a request for Best and Final Offers was issued on September 29, 2008.

DISCUSSION/NEGOTIATION RECORD

Best and Final Offers (BAFOs) for the replacement condenser modules were received on October 9, 2008, from all three vendors. These BAFOs were evaluated by a Source Evaluation Panel (SEP) using pre-established weighted evaluation criteria. The SEP ranked the proposal provided by TEI as being technically most advantageous and representing the lowest cost to Energy Northwest.

Efforts to identify the most cost effective means of performing the tasks necessary for the removal of the existing condenser modules and installation of the new replacement condenser modules during the R-20 outage are ongoing. Award of the module vendor contract will assist these efforts by eliminating current design unknowns and by clarifying installation task scopes.

FINDINGS OF FACT RFP 651803 (cont)

EVALUATION

Evaluations of the Submitted proposals were conducted by a Source Evaluation Panel (SEP) with over site by a Contract Review Board (CRB). The SEP makes its recommendation to the Source Selection Official (SSO) who has the responsibility of making the final decision. See the attached documents for details related to the personnel performing the evaluations, evaluation of submitted prices, and selection criteria with evaluation points used to reach a recommendation for award to the SSO.

- MAIN CONDENSER REPLACEMENT PROJECT PROCUREMENTS -- Appointment of Source Selection Official (SSO) including the Source Evaluation Panel (SEP) and Contract Review Board (CRB).

- BAFO Pricing Comparison For RFP 651803 Condenser Module Procurement

- Condenser Module Proposal Evaluation Criteria for RFP 651803 including assignment of points by the SEP.

FUNDING STATEMENT

This procurement is authorized by Pass Port Contract Requisition No. 651803 having an estimated value of $37,000,000. Costs will be allocated to Work Order 01125228 – 15.

SPECIAL PROVISIONS

The contract is a fixed price contract having liquidated damages for late module delivery and provisions for performance payment adjustments for increased / decreased condenser performance.

RECOMMENDATION

It is recommended that a contract be awarded to Thermal Engineering International in the not-to-exceed amount of $37,000,000 for the design, fabrication, and delivery of Replacement Condenser Modules as described in RFP 651803. This price includes a fixed price element and allowances for cost reimbursement elements such as performance bond and transportation costs.

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FINDINGS OF FACT RFP 651803 (cont)

APPROVALS

Prepared By: W. G. Edmonds — 10-23-2008
W. G. Edmonds, Pr. Contracting Officer — Date

CONCURRENCES:

10-24-08
B. G. Berglin, Condenser Replacement Project Manager — Date

10/27/08
P. R. Bradley, Assistant General Counsel — Date

10-27-08
D. A. Swank, Manager, Major Projects — Date

10/28/08
G. A. Sponholtz, Supervisor, Purchasing & Contracts — Date

acting for Lynne Pagel — 10/28/08
L. A. Pagel, Manager, Supply Chain Services — Date

S. K. Gambhir, VP Technical Services — Date

Condenser Module Proposal Evaluation Criteria RFP 651803

Evaluation Item	Weight	Points		
		Supplier Name		
		Toshiba	Yuba	TEI
TECHNICAL EVALUATION				
1. Offeror's Response to Procurement Specification/Statement of Work Requirements Completeness	**125**	60	90	110
2. Offeror's Relevant Experience	**125**			
a. Performance-Delivery Record.	15	15	15	15
b. Past Pullout test Historical Performance.	5	2	4	4
c. Demonstrated experience of similar size condenser fabrication and nuclear experience.	10	7	8	8
d. Demonstrated commitment to long term success in condenser replacement	10	10	10	10
e. Past responsiveness to engineering and field modifications	10	5	8	10
f. Previous condenser historical performance record.	75	75	70	70
3. Proposed Team Composition including Qualifications and Experience	**55**			
a. Key personnel	10	2	8	10
b. Proposed subcontractors	5	5	1	5
i. Tube subcontractor's QA and procedural compliance	40	10	30	40
4. Consideration of Offeror's Design and Fabrication Capability and Capacity	**30**			
a. Facilities and manufacturing processes	15	15	8	10
b. QA Program	15	5	10	14
5. Guaranteed performance	**60**			
a. Guaranteed Vacuum performance level (Desired 2.41 max)	60	60	55	60
b. Guaranteed Condensate Temperature Depression (3 degrees F max) *				
6. Consideration of Offeror's Schedule (including subcontractors)	**65**			
a. Fabrication schedule	30	10	20	30
b. Delivery Plan and resource loaded schedule	25	5	18	25
c. Technical and contractual risks	10	5	8	10
7. Offeror's:	**50**			
a. Technical and administrative alignment with Energy Northwest	10	4	8	10
b. Technical interchange of information	10	4	8	10
c. Project ownership	30	10	22	30
8. Overall technical adequacy of the proposal and the likelihood, as judged by Energy Northwest, that the Offeror can meet a required delivery date of July 7th, 2010 given the estimated award date of November 15th, 2008.	**50**	30	38	48
SUB-TOTAL WEIGHT	**560**	339	439	529
COMMERCIAL EVALUATION				
1.0 Acceptance of Terms and Conditions	**100**	60	40	25
2.0 Cost	**250**	205	245	250
SUB-TOTAL WEIGHT:	**350**	265	285	275
TOTAL WEIGHT:	**910**	604	724	804

* Re-heat was provided as an option for BAFO in Addendum 9, Option 2 of the Pricing sheet. The Project team determined from visiting all vendors and evaluating each design and that MWe added from claimed efficiency could not be guaranteed, the value of the requirement in the specification was severely reduced and should be removed.

Source Evaluation Panel Technical evaluation comments:

1 Toshiba:Several exceptions to technical requirements, 25g tubes offered vs. 24g requested, 25g are not used in the US. Shell support design deferred to Westinghouse, material not offered for supports.
Yuba: Did not provide stress analysis for the tube sheet or a design summary as requested. They won't customize their design to fit the Columbia's configuration. An example: Sub-cooling is a standard feature whether you use it or not which could be used to add more tubes if it's not used. Their design increases risk of installation issues without a guarantee of the best back pressure (MWe gain).
TEI: Least amount of exceptions to SOW, design of module is fit around the existing shell design.

2a. All had a good performance delivery record

2b. Toshiba: Information provided was 20 years old and relies on the clad joint with perfect cladding where the weld joint takes the load.
Yuba: A pullout test can be performed at anytime in the shop. They took exception on measuring the wall thickness of 1 out of 50.
TEI: Provided a pullout test procedure but can not perform it right away. They can perform an apparent wall reduction. No exceptions taken by TEI.

2c. Toshiba: Haven't performed a retrofit of a Westinghouse design. Design is flexible to meet Energy Northwest needs.
Yuba: Yuba has designed and provided intermediate water boxes. Floating tube sheet design not flexible to changes
TEI: just performed Big Bend project because they understand the Westinghouse Design. They have not built an intermediate waterbox.

2d. All demonstrated success to a long term commitment of Condenser manufacturing

2e. Toshiba: After field visit and BAFO, the same information was provided even though revised information was requested. Toshiba does not provide a shell analysis and in the BAFO, Westinghouse is providing it. Westinghouse and Toshiba did not demonstrate seamless cooperation.
Yuba: Yuba's computer program for design is conservative and proven. Their staff doesn't appear to be as flexible to changes.
TEI has a solidworks model that can they can respond quickly to changes and demonstrated it during the field visit. They can quickly change drawings.

2f. Toshiba: Fukushima plant started up without any leaks with a new Toshiba Condenser.
Yuba: Lots of other utilities have expressed concern about Yuba's historical performance record. When asked, Yuba had two incidences of performance test they did not meet but fixed them.
TEI: Doesn't have the concern from other utilities, but did have an issue at Ft. Calhoun performance of the condenser.

3a. Toshiba: Westinghouse the middle man to Toshiba. No direct link to Toshiba and their coordination with each other needs improvement
Yuba: Technical team not as strong as TEI. Didn't know who performs stress analysis or mechanical engineering. Organization submitted in BAFO not as strong as TEI's. Project Manager was not dedicated to the Project.
TEI: Very Strong Team submitted with a dedicated Project Manager. Strong technical team and Project Management both at the shop and engineering location

3b. Toshiba: Only used two subcontractors. 1)Tube sheets 2)tubes.
Yuba: Five proposed subcontractors, Yuba did not know which subcontractors they are going to use.
TEI: Only subcontractor is a high quality tube supplier, TEI will manufacture everything else in their own shop.

3bi. Toshiba: They never provided copies of their QA/QC procedures that were requested.

Yuba: Haven't committed to using Valtimet or Ameritie as a tube supplier. Ameritie tubes are a lower cost but their quality program has issues that need to be corrected. The Project Team has both visited the Valtimet and Ameritie factories.
TEI: Has committed to using Valtimet as a tube supplier that has a strong QA program.

4a Toshiba: Quality of work very good and a clean shop. Organization of shop could use some improvement.
Yuba: Very cramped shop, feed water heaters also manufactured. Quality of workmanship better but don't know how their subcontractors perform because they wouldn't commit to who they were so EN could evaluate them.
TEI: Clean shop, lots of room, quality of workmanship could use some improvement.

4b: Toshiba: Their quality personnel could not provide information how they are involved in the manufacturing process. They don't appear to be involved with hold points.
Yuba: Quality Personnel person on site every three weeks. Also visits subcontractors. Quality Personnel didn't appear to work seamlessly with the shop. Checked tubes in the shop during visit, tubes were discovered to be scratched. They did not come back with a strategy to keep the modules clean even though they were asked during the site visit and in the BAFO.
TEI: Lots of improvement since the Columbia's feed water's manufactured. Fulltime person at Sepulpva shop, Corporate QA personnel also located in Joplin, MO close by. Tubes being manufactured in the shop were not found to be very clean during a site visit.

5a. Toshiba: Met requirement but it's based upon using 25 gauge tubes where minimum 24 gauge were specified.
Yuba: 2.36 hg", did not take credit for gains in re-heat, feedback from Technical Consultants is they are conservative in their ratings.
TEI: 2.30 hg", used 23 gauge in their calculation that is conservative. Feedback from Technical Consultants they will not be conservative in their rating.

5b. Re-heat was provided as an option 2 in Addendum 9 of the BAFO pricing sheet. The Project team determined from visiting all three vendors (between the initial proposal and the BAFO) and evaluating each vendor design, there were not guarantees of MWe gained from efficiency. As a result, the value of the requirement in the specification was severely reduced. Pam Bradley, Glen Edmonds, John LaSalle, Craig Grier, Jim Parker, Dave Tedeschi and Brian Berglin all agreed with the removal of the points for BAFO evaluation.

6a. Toshiba: Very high level 5 line schedule provided. Limited information in schedule. No subcontractors showed up on schedule.
Yuba: Detailed fabrication schedule provided. No subcontractors showed up on schedule.
TEI: Detailed fabrication schedule provided. Most detail provided.

6b. Toshiba: Delivery plan will not meet delivery schedule but will deliver in a one month time frame. Proposed delivery time was 3 months after request in BAFO.
Yuba: Will meet specified delivery schedule but over a five month period where one month was specified.
TEI: Will meet specified delivery schedule but over a two month period where one month was specified.

6c. Toshiba: Communication plan through Westinghouse for Toshiba adds risk to miscommunication. Toshiba takes has full ownership of the module it until it hits the unloading dock and turns it over Westinghouse. Not one party involved. Proposal states Westinghouse will be performing the condenser shell analysis which creates a lot of risk because they don't design condensers.
Yuba: More exceptions taken than TEI. Shop personnel concerned with Condensers in the shop. Shop is performing over its capacity. Water boxes need to be modified. Yuba does not subcontract engineering.
TEI: Least exceptions were taken by TEI. Shop is relatively new and has lots of room. Three different condenser were being manufactured at one time. All the machine work is not performed in the shop whereas the shop is a lot cleaner than Yuba's. Joplin performs all the machining and is their Joplin, MO shop keeping the particulate leveling the shop at a very low level.

7a. Toshiba: Had a separate company for Project Management.
Yuba: Did not have a dedicated Project Manager
TEI: Dedicated Project Manager at the same site with the Engineering organization. A second Project Manager was named and will be stationed at the manufactured facility.

7b. Toshiba: Communication barriers through the Westinghouse filter provides added time. A middle person creates a higher potential for technical communication errors.
Yuba: Hesitant to explain how they perform their manufacturing in detail.
TEI: TEI engineering very open to questions and provided answers when requested.

7c Toshiba: Did not commit to who would be on the Project for both Westinghouse and Toshiba.
Yuba: Did not know who exactly will be on the Project
TEI: Project personnel identified for the project which the Project team met on their visit to TEI's facilities. They also presented a Project Plan on how they would perform the Project.

8 Toshiba: Provided flow analysis and a lot of what was requested. Information was not provided for EN Engineering to validate the analysis.
Yuba: Did not provide the analysis requested. Flow analysis was not provided.
TEI: Provide most of what was requested except for Flow analysis. Also provided Engineering for lifting and rail system outside of condenser bay area.

Source Evaluation Panel Commercial Comments:

1. Toshiba: Took no exceptions to Amendment 10 but there are still lots of remaining exceptions that still need to be negotiated.
Yuba: Took minor exceptions to Amendment 10 and in general their exceptions appear to be reasonable.
TEI: Amendment 10 sent out to not take exception to these four terms. They took exceptions to 3 of 4, but the liquidated damages exceptions are difficult for us to clarify and level the field. Exceptions they did take were reasonable and well thought out.

2. Toshiba: $43.6M for 1" tubes.
Yuba: $36.9M for 7/8" tubes - $34.79M for 1" tubes - Delta = $2.13M
TEI:$36.14M for 7/8" tubes - $33.23M for 1" tubes - Delta = $2.91M

BAFO PRICING COMPARISON FOR RFP 651803 MODULE PROCUREMENT

Description	Toshiba	YUBA	TEI	
12 Modules(Ti-Clad Tubesheet and 7/8" tubes) and 3 intermediate waterboxes	Not provided	$34,180,000	$34,821,000	Toshiba: Not provided Yuba: Their base price includes a re-heat system which is their standard design TEI: Prefers to offer solid titanium tube sheets due to a bad experience with titanium cladding. Savings of using cladding is $27K.
12 Modules(Ti-Clad Tubesheet and 1" tubes) and 3 intermediate waterboxes	$40,227,000	$32,028,000	$31,965,000	Toshiba: This is the only option offered. It includes Condensate re-heat system and sparger system. There is a $29F2K savings if you select the standard 25 gauge tubing wall thickness. No one in the US has used 25 gauge tubes yet. BN Engineering advises against using 25 gauge tubes. Revised cost of 20 gauge tubes $37,329,000 Yuba: Same comment as 7/8" tubes above TEI: Same comment as 7/8" tubes above
12 Modules(Titanium Tubesheet and 1" tubes) and 3 intermediate waterboxes	Not provided	Not provided	$31,906,000	Toshiba: Not provided Yuba: Not provided TEI: This price includes all the temporary and permanent support material and design.
12 Modules(Titanium Tubesheet and 7/8" tubes) and 3 intermediate waterboxes	Not provided	Not provided	$34,845,000	Toshiba: Not provided Yuba: Not provided TEI: This price includes all the temporary and permanent support material and design. At 1.8 Tg/Megawatt electric ($800/Megawatt hour. The $3870K delta will take 4 years to recover and provide a $2.9M positive NPV at 2024 using 7/8" diameter tubes.
12 Modules(Ti-Clad Tubesheet and 1 1/4" tubes) and 3 intermediate waterboxes	Not provided	$36,368,000	Not provided	Toshiba: Not provided Yuba: Same comment as 7/8" tubes above TEI: Not provided
Condensate re-heat system originally specified and provided as an option in BAFO	Not provided	Included	Not provided	Toshiba: Not part of Design Yuba: Integral part of Design and no additional cost for option. Re-heat system replaces area where tubes would be. Benefit vs. tube failure is estimated to potentially be 3 Months gain. The risk of utilizing Yuba's design includes the recommendation of using new waterboxes or retrofitting our existing water boxes adding additional cost not yet estimated. BDP determined the risk of using this design not weighs the benefit of the 3Mths potential gain which cannot be guaranteed at this point. TEI: Not part of Design
3 new inlet and 3 new outlet waterboxes	$3,797,000	$1,710,000	Not provided	Toshiba: Not originally offered but prohibitively expensive Yuba: Due to their design, inlet & outlet waterboxes are the least cost for Yuba and dividing them will cause EIP to modify existing waterboxes and piping to adapt to Yuba's design leading to additionally costs that have not been estimated. TEI: Design is a rebuild centered around the original design which has been demonstrated at other sites. Purchasing inlet and outlet waterboxes is not needed with this design.
Provide temporary supports design and entire permanent design (inside shell) and material	$864,000	$600,000	Included	Toshiba: Did not supply all the support materials asked for in the BAFO. Attachment F, Toshiba Scope Plan item 11 includes $156,000 for the design for removal of the existing modules but not sure if this is included in the price. Westinghouse to design the rail systems inside the Condenser shell, not Toshiba. Yuba: Material not normally provided TEI: All included in price
Additional manways and ladder rings being added to address current safety concerns	$300,000	$10,000	Included	Toshiba: Price includes sparger system Yuba: none TEI: Included in price
Sparger system injecting leak detection in the intermediate water boxes	1	$60,000	Included	Toshiba: Price includes sparger system and is shown with the additional manway pricing Yuba: none TEI: Included in price
1/2" thick main tube supports vs specified 5/8"	Not provided	Not provided	-$114,000	Toshiba: Did not offer alternative cost & reduction in module weight Yuba: Did not offer alternative cost and reduction in module weight TEI: Shipping cost will also be less because of reduced weight. Additional savings can be achieved but it was not offered with proposal
Provide design of the rail system outside of the condenser bay that would load the condenser modules onto a trailer for shipment.	Not provided	Not provided	Included	Toshiba: Not enough time in BAFO to supply price Yuba: Design included in offer TEI: Design included in offer
150 Control tubes and holes in the tubesheets	Included	Included	Included	Toshiba: Reduced $28,000 if 30 control tubes and holes are used Yuba: No exception TEI: No exception
Shipping	$648,000	Included	$196,000	Toshiba: Initial shipping estimate only. Overseas shipping may be missing? No rate in overseas shipping included. If able to modify the Late Delivery Liquidated Damages to reflect the dates of delivery, liquidated damages could reduce price by $810,000 Yuba: Included in price? TEI: Estimated price without weight reduction utilizing 1/2"
Module Delivery time based on a one month period by July 2010. (D&I Contractor Cost baseline is also 1 month) (Cost not added to total below).	Does not meet	Does not meet	Does not meet	Toshiba: Meets the one month delivery but not until October 2010 instead of the required July 2010. Yuba: July delivery but stretched out 5 months, additional D&I cost should be added to this offer or a different delivery date negotiated to coordinate with D&I contractor currently scheduled for one month delivery. TEI: July delivery but stretched out 1 month, additional D&I cost should be added to this offer or a different delivery date negotiated to coordinate with D&I contractor currently scheduled for one month delivery.
Overseas Tariff	Included	Not required	Not required	Toshiba: Price includes 5.8% import duties Yuba: Not required TEI: Not required
Ten items in Toshiba's Attachment C of BAFO identifying increased costs that were not part of BAFO.	$1,835,000	N/A	N/A	Toshiba: Attachment F, Toshiba Scope Plan items 12, 13, 16, 17, 18, 20-2, 21, 24, 26, 27, 28, 30 has $1,835,000 of additional costs associated with the procurement. Yuba: None identified TEI: None identified
Subtotal 7/8" Tubes		$36,918,000	$36,434,000	
Subtotal 1" Tubes		$34,769,000	$32,591,000	
Performance Bond 7/8" tubes	Included	Included	$708,000	Toshiba: Included in the price Yuba: Included in the price 100.0% of total 7/8" tube price.
Performance Bond for 1" tubes	Included	Included	$651,000	Toshiba: Included in the price Yuba: Included in the price 153.0% of total 1" tube price. $57,000 less cost than 7/8" tubes.
Total 7/8" Tubes		$36,918,000	$36,142,000	Toshiba: No bid on 7/8" tubes Yuba: Delta between 7/8" & 1" tubes. $2,128,000 additional cost. Vacuum gain is .04"hg TEI: Delta between 7/8" & 1" tubes. $2,853,000 additional cost. Vacuum gain is .06"hg. 8 years to NPV=0. NPV@2024=$2M/yr. per Asset Management Chris Infall.
Total 1" Tubes	$40,015,000	$34,769,000	$33,242,000	Toshiba: Cost is out of range and significantly greater than other competitors. Yuba: Less cost than 7/8" diameter tubes TEI: Least initial cost, performance bond savings on lower price is an additional $17.0K. Backend savings was based on $2,853,000 additional cost, $2,000,000 + $51,000 = $2,910,000.
Total 1 1/8" Tubes	Not an option	$31,376,000	Not an option	Yuba: Lowest initial cost. Not allowable option to be considered because of back pressure is 2.48" hg whereas the spec and business case was based on 12 Mwe at 2.41"hg back pressure.
Delta between 7/8" and 1" Titanium Tubes		$2,128,000	$2,910,000	

Yellow-used in figuring price
Orange-questionable items that need answers
Red-concerns
Green-recommended compatible selected options
Orange-delta of 7/8" tubes vs. 1" tubes

Notes:

1. TEI has a one piece waterbox that can be fit up in the shop ahead of time. They will split the waterbox if they need to. They haven't installed a new intermediate waterbox before. They have just performed the Big Band Project on a like design.
2. Yuba has a split intermediate water box design. They have used this split design before and been successful.
3. Yuba provides no cladding for the waterboxes. TEI does
4. Yuba supplies the re-heat system for the modules no matter if we use it or not.
5. Extensive modification to the existing inlet and outlet waterboxes must be performed with Yuba. Yuba's price comparison includes installing new waterboxes to reduce the risk.
6. TEI can stack the modules and fit the intermediate waterboxes in the shop before shipment to assure alignment
7. Yuba's design requires internal supports inside the waterboxes, whereas TEI's does not require it.
8. Yuba did not supply the stress analysis documents
9. Yuba did not provide historical tube results requested in the Specification
10. TEI did not provide a re-heat design system

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INTEROFFICE MEMO

DATE: August 26, 2008

TO: S. K. Gambhir, Vice President, Technical Services

FROM: J. V. Parrish, Chief Executive Officer

SUBJECT: MAIN CONDENSER REPLACEMENT PROJECT PROCUREMENTS

REFERENCE: CONTSEG, Source Evaluation Guidelines, September 2000

On April 28, 2008, a memo was issued assigning you as the Source Selection Official (SSO) and appointing a Source Evaluation Panel and Contract Review Board for the two primary procurements supporting Columbia Generating Station's Main Condenser Replacement Project. The first procurement is for the fabrication and delivery of twelve condenser modular bundles and three intermediate waterboxes; the second procurement is for associated design and installation services. On July 10, 2008, a memorandum was issued revising the composition of the Contract Review Board and Source Evaluation Panel.

As a result of recent staffing changes and the need for backup support, the membership of the Source Evaluation Panel has again changed. Accordingly, the appointment memo is revised to reflect the changes to the Source Evaluation Panel membership as shown below:

Source Evaluation Panel

Chairman:	B.G. Berglin, Condenser Project Manager
Members:	C.L. Grier, Condenser Project Cognizant Engineer
	J.R. Lasalle, Pr. Engineer
	D.R. Senner, Quality Supervisor
	D.A. Swank, Manager Projects
	L.W. Syverson, Quality Auditor II - NDE
	K.A. Whelan/G. Edmonds, Pr. Contracting Officers
	L.J. Woods, Sr. Engineer
Recorder:	Donna Sylvester, Administrative Assistant
Advisors:	R. Bayer, Independent Contractor
	P.R. Bradley, Assistant General Counsel
	J.W. Dabney, Maintenance Component Group Manager
	D.A. Garza, Condenser Project HP Coordinator
	R.S. Korenko, Independent Contractor
	L.D. Morrison, Chemistry Specialist

J.E. Parker, Independent Contractor
A.D. Rains, Staff Attorney
D. Tedeschi, Independent Contractor

Contract Review Board

Chairman: L.A. Pagel, Manager, Supply Chain Services
Members: D.K. Atkinson, VP, Nuclear Generation
J.E. Bekhazi, Planning/Scheduling Outage Manager
A.E. Mouncer, VP Corporate Services/CFO

kaw

1/25/07
Chris T.
Carl G.

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Condenser Replacement Project/ Project No. 01125228

PHC Meeting

January 24, 2007

Joe Frisco

Background

- Sargent and Lundy Main Condenser Upgrade Scoping Study completed in Dec of 2006
  - Condition assessment
  - Copper reduction options
  - Thermal performance analysis
  - Installation options and considerations
  - Budgetary estimates
  - Dose and fuel impacts
- Recommendations Summary
  - Do nothing option not a realistic option
  - Recommend replacement at earliest opportunity
    - Modular with Sea Cure or Titanium
    - Retube with Sea Cure or Titanium
    - Conduct cost benefit to determine most appropriate path

Cost Benefit Analysis – Results

Present Value Details - Magnitude and Sensitivity of Input Assumptions

	FY07 $M NPV					
Impact/Description	**Base Case**	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Installation Costs	$ (23.0)	$ (49.0)	$ (24.0)	$ (28.4)	$ (55.3)	$ (70.5)
Installation Outage Impacts/ Incl Dose	$ (18.7)	$ (24.9)	$ (32.7)	$ (32.7)	$ (85.0)	$ (85.0)
Chem Decon (incl dose)	$ (11.7)	$ (8.0)	$ (8.0)	$ (8.0)	$ (11.7)	$ (11.7)
Fuel Failure Risk	$ (5.8)	$ (3.0)	$ -	$ -	$ (3.0)	$ (3.0)
Projected Downpowers for Tube Leaks	$ (10.2)	$ -	$ -	$ -	$ -	$ -
Reduced Dose	$ 17.5	$ 19.4	$ 19.4	$ 19.4	$ 17.5	$ 17.5
(Derate)/ Increased Generation	$ (13.6)	$ -	$ (25.6)	$ (15.8)	$ 69.6	$ 69.6
Added ongoing Inspection Costs for Modular	$ -	$ -	$ -	$ -	$ (1.8)	$ (1.7)
Total	**$ (65.5)**	**$ (65.4)**	**$ (71.0)**	**$ (65.5)**	**$ (69.6)**	**$ (84.7)**

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Recommended Options

- Sea Cure material selection NOT recommended by our materials engineers
  - Tube processing consideration – ability to find defects/complex material mix
  - Future inspection challenges – ability to find defects
  - Titanium proven performer in many more installations

Option 3 – pro's and con's relative to modular replacement

- Pros
  - Relatively Low Capital Costs
  - Easier Installation – can be accomplished in FY09
  - Technical and Installation risk - Low
  - Gets copper out of the plant the quickest
    - Getting dose reduction ASAP
- Cons
  - Summer Derate possible now and with Extended Power Uprate
    - Due to unknowns not considered in business case (EPU)
    - If/When EPUR occurs evaluate further for other mods to gain back potential losses — C.Tower mods, reheater
  - Muntz Metal tube sheet concern — but a lot of operational experience out there.
- Risks
  - Titanium availability could drive to R20 → 2011

not huge $

— recent contacts say this isn't an issue

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Cost Benefit Analysis - Key Financial and Economic Considerations

- Total Capital Costs
- Outage Duration
- Value of Lost Generation
- Value of Increased Generation
- Uprate Capability
- Fuel Failure Risk
- ALARA

Key Assumptions/Qualifications

Note: All alternatives will result in condenser retube

Discount Rate		6.5%
Escalation		3.0%
Man-rem exposure costs $K/man-rem	$	25
FY09 Outage w/o Condenser (days)		35

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Cost Benefit Analysis – Specific Assumptions

Other Cost Impacts Assumptions		FY07 $K Base Case	Option 1	Option 2	Option 3	Option 4	Option 5
Radiation							
Radiation Impacts Retubing (man-rems)		12	12	12	12	60	60
Cost per Man-rem		$ 25	$ 25	$ 25	$ 25	$ 25	$ 25
Total Radiation Impacts		$ 300	$ 300	$ 300	$ 300	$ 1,500	$ 1,500
Installation Outage Impacts							
Incremental Outage Impact (Days)		25	33 ~~25~~	33	33	85	85
Lost MWH from Outage Impact	1107	664,200	664,200	876,744	876,744	2,258,280	2,258,280
Annual Derate/Increase							
Lost MWH from Summer Derate		17133	-	27,818 (1 PP day)	17,133	-	-
Increased Generation						~~$~~ 91,542	~~$~~ 91,542
Additional Annual Inspection Costs							
Per Outage → more tubes: 1/3 each outage		0	0	0	0	220	200
Chemical Decon (rough cost)		$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367	$ 4,367
Radiation Impacts from Decon (man-rems)		15.00	15.00	15.00	15.00	15.00	15.00
Radiation Benefits for Copper Removal							
Man-rems Saved		50	50	50	50	50	50
Value of Man-rems saved		$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250
Fuel Failure Risk from copper							
Probability of failure Annually prior to retube post FY09		0.05	0.05			0.05	0.05
Cost of a failure							
Direct Cost		$ 4,000	$ 4,000			$ 4,000	$ 4,000
Fuel Purchase		$ 25,000	$ 25,000			$ 25,000	$ 25,000
Root Cause Analysis		$ 4,000	$ 4,001			$ 4,000	$ 4,001
Radiation Costs of a failure		$ 425	$ 425			$ 425	$ 425
Total Fuel Failure Costs		$ 33,425	$ 33,426			$ 33,425	$ 33,426
Annualized Cost for Fuel Failure Risk		$ 1,671.3	$ 1,671.3			$ 1,671.3	$ 1,671.3
Downpowers for Condenser Problems Post FY09							
Direct Costs		605					
Annual Average Lost Generati	40	$ 2,358	Based upon 6 in the last 3 years due to condenser				
Total Downpowers Loss and Cost		$ 2,963	Estimated				

35 day Base outage assumed.

incremental

odds of an event.

cost of event.

John Hansen & Shaw Bien

(10-11 avg mwhrs)

is this value correct. Ron & Inga disagreement.

cause don't replace till 2011

cost of lost generation.

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Condenser Replacement Project
PHC Update

Project No. 00608601

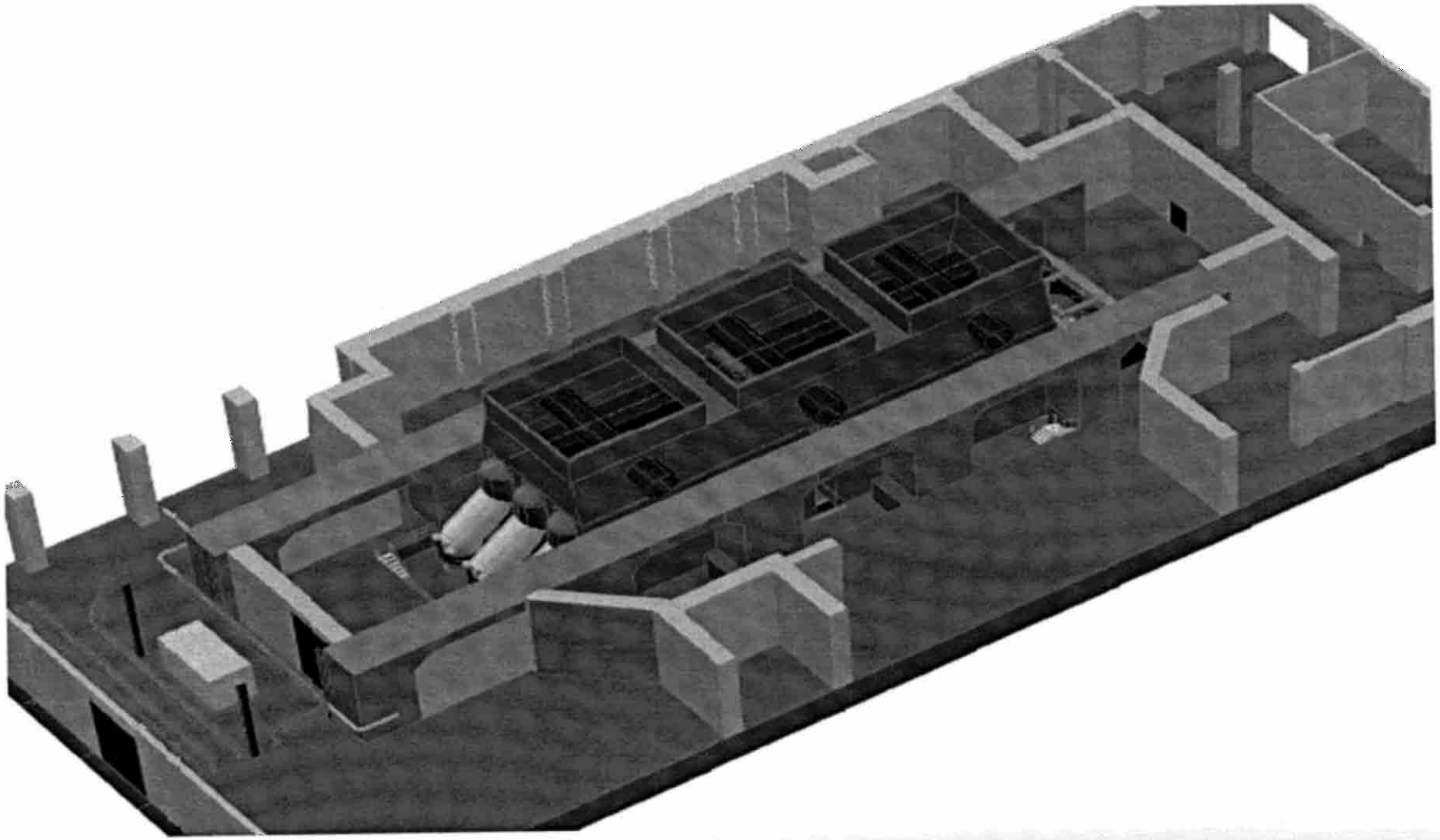
January 17, 2008

Brian Berglin

Presentation Outline: Condenser Replacement

- 3D overview
- R-19 Time Line Schedule
- R-19 Design Changes
- Other R-19 non-EC
- R-20
- Budget Review
- FY08 through FY12 Schedule

Main Condenser Project: 3D overview



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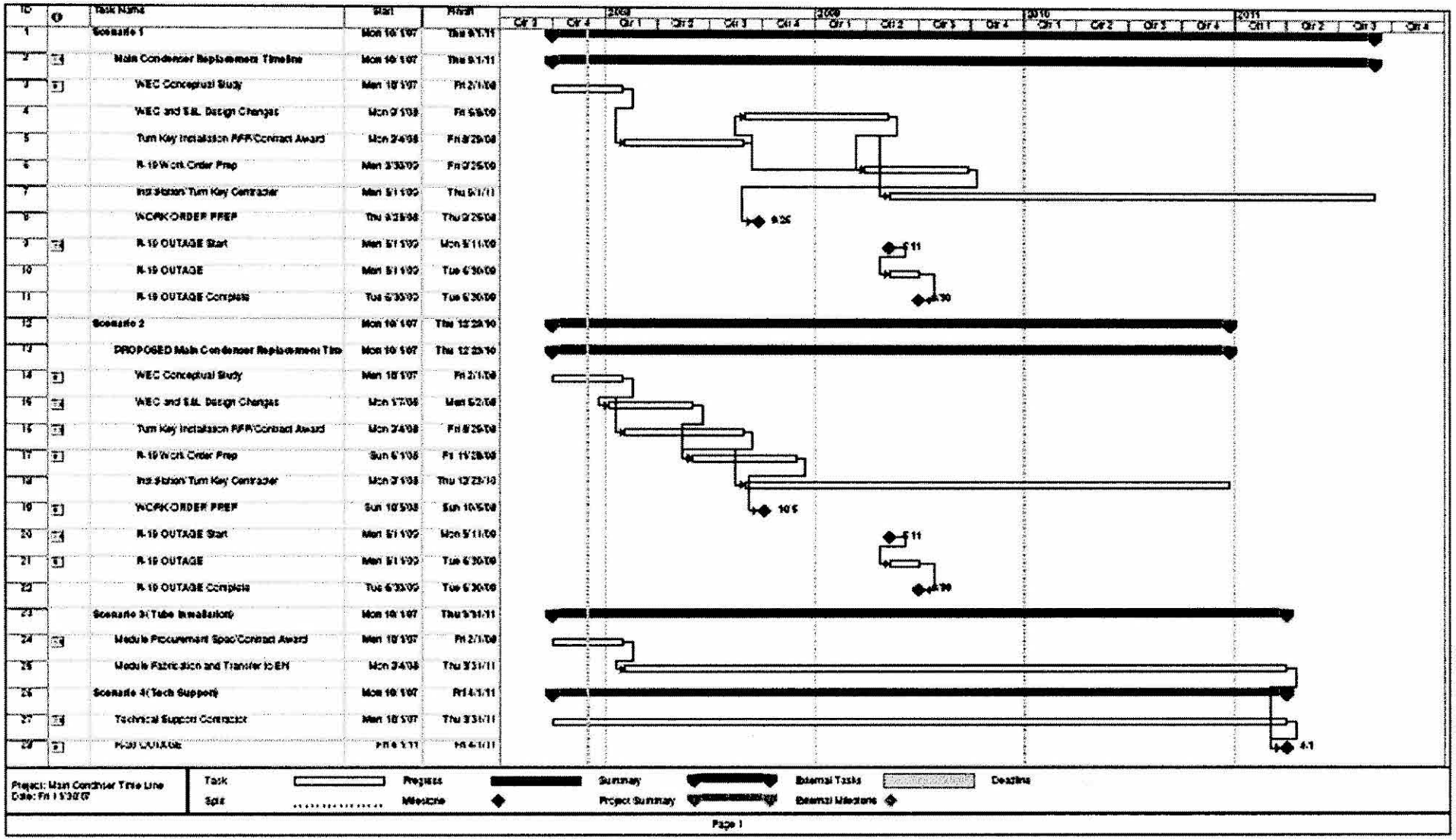
Main Condenser Repl R-19 Time Line



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R-19 Design Changes

- EC 6693 Condenser travel path interference modifications (may break following into additional ECs)
  - **West concrete wall removal & temp shielding installation for operation** (**SS** or DS)
  - **Relocate 3" CAS pipe West Turbine wall interference**
  - **Relocate HWC Air Injection skid**
  - **Relocate H2 pipe outside TG Building**
  - **Relocate power/control H2 Chem cable (thru TG wall)**
  - **Relocate 12" COND short cycle return pipe – in between stator water cooling and inner west wall**
  - 8 cable trays equating to approx 178 cables (DS)
    - 14 Div A & B Trays which includes E-TR-S power

R-19 Design Changes (continued)

- **EC 6693 (continued)**
  - **East concrete wall removal** (1 of 2 locations)
    - Option 1 – through Relief Valve room
    - Option 2 - Directly through east wall (restricted use of corridor)
  - **Relocate 1/2" Demineralized Water & 6" Fire Protection pipes**
  - **Supports under hot well false bottom for rail system**
  - **Install FWH 1A,1B,1C supports**
  - Install gantry crane inside Condenser Bay shield area (SS)

R-19 Design Changes (continued)

- EC 6692 –
  - Boundary Valve Temperature Monitoring of Condenser Inlets
    - Heater Drain
    - Bleed Steam
    - Main Steam
    - Miscellaneous Drains
  - Condenser Performance Monitoring (ASME PTC 12.2 Testing Code)
    - Pressure instruments in the main condenser shell- 9
    - Circ Water outlet temperature instruments - 18
    - Circ Water Ultrasonic Flow Transducer -1

Other R-19 non-EC & Project Work

- Desludge Hot well – PN:00608601
- West slop drain piping replacement PN:01413001
- Dog bone seal replacement - WO
- Replace cracked expansion steam bellows – PN:01811901
- BS Extraction Pressure Sensing Lines are eroded – OUTAGR19
- Replacement of eroded hood spray piping (contingency) – WR 29061192

R-20 Design Changes

- EC 6694 Main Condenser Modular Replacement

Budget Review

- Current Budget - $1.8M
- Proposed revised budget – $4.08M
  - Complete Project Plan – 01-31-08
  - Revise Project Schedule – 02-15-08
  - PCF for revised FY08 funding - 03-08
- FY09 Budget - $36.5M

Condenser Replacement Schedule

- FY-08 Path Forward
  - Complete Conceptual Study "Project Plan"
  - Complete independent Business Case by Huron
  - Commence R-19 Design Changes (Elect, Mech, Civil) & Planning
    - EC 6692 Boundary Valve Temperature Monitoring of Condenser Inlets & Condenser Performance Monitoring
    - EC 6693 Mech/Elect Interferences
  - Obtain full project funding from stakeholders
  - Modular tube bundle Material Procurement
  - Turnkey Contractor contract preparation

- FY-09 Path Forward
  - Complete R-19 design modifications & Work Order Planning
  - Complete Turn-Key Contract process / award contract
  - Mobilize Turn-Key Contractor
  - Implement R-19 design modifications

Condenser Replacement Schedule

- FY10 Path Forward
  - Complete on-line design modifications
  - Complete R-20 Design Changes
- FY11 Path Forward
  - Receive Main Condenser modules on-site
  - Implement R-20 design modifications
  - Condenser module replacement
- FY-12
  - Post Outage Demob & Disposal

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Plans to Ensure Reliability Following a Major Maintenance Outage

Condenser Replacement Project

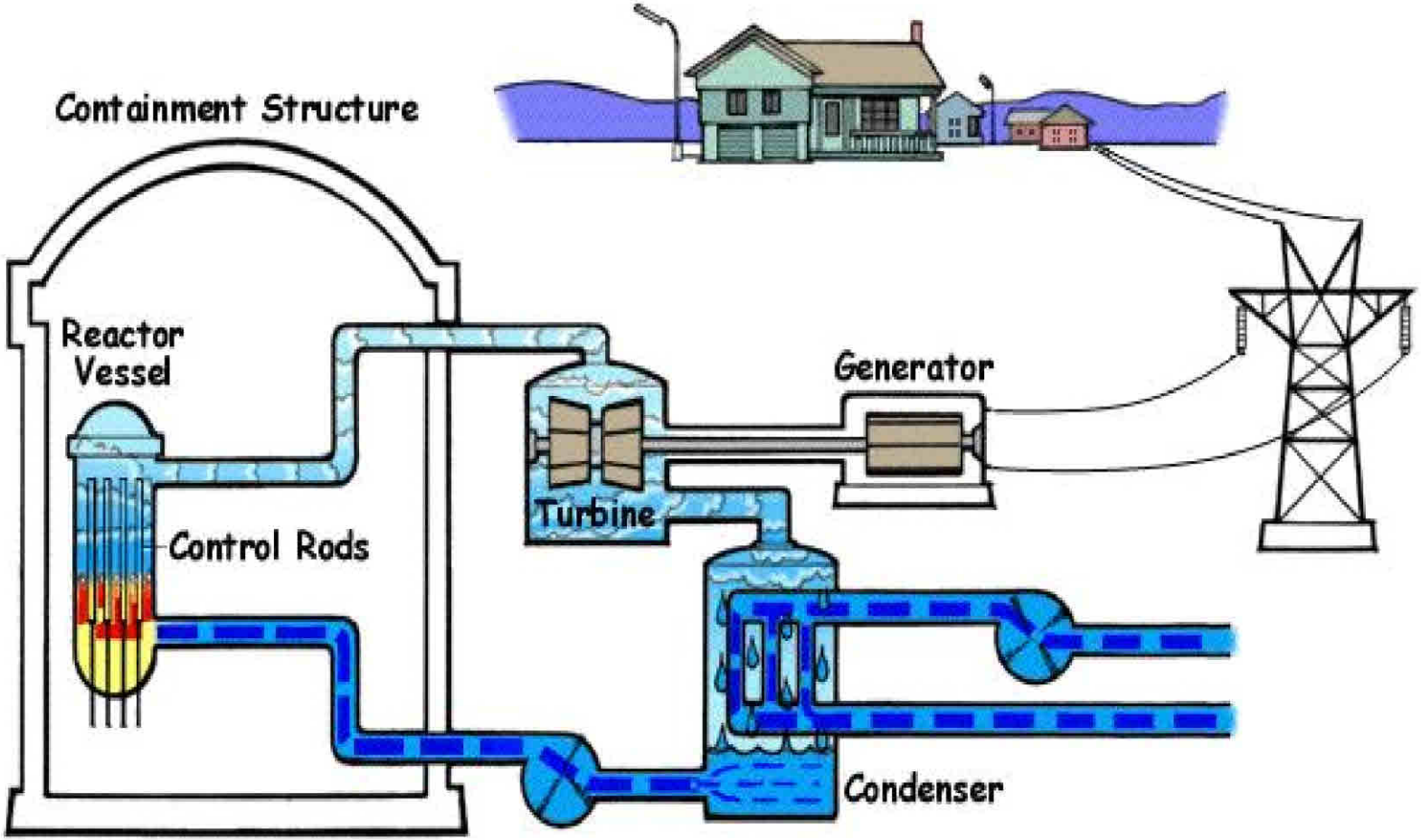
Sudesh Gambhir/Brian Berglin

11-18-09

Overview

- BWR Steam Cycle – How a condenser works
- Review of Business Case
- Project Overview
- What does success look like
- How is the Project assuring success
- Risk identification and monitoring
- Plans to assure reliability

BWR Steam Cycle



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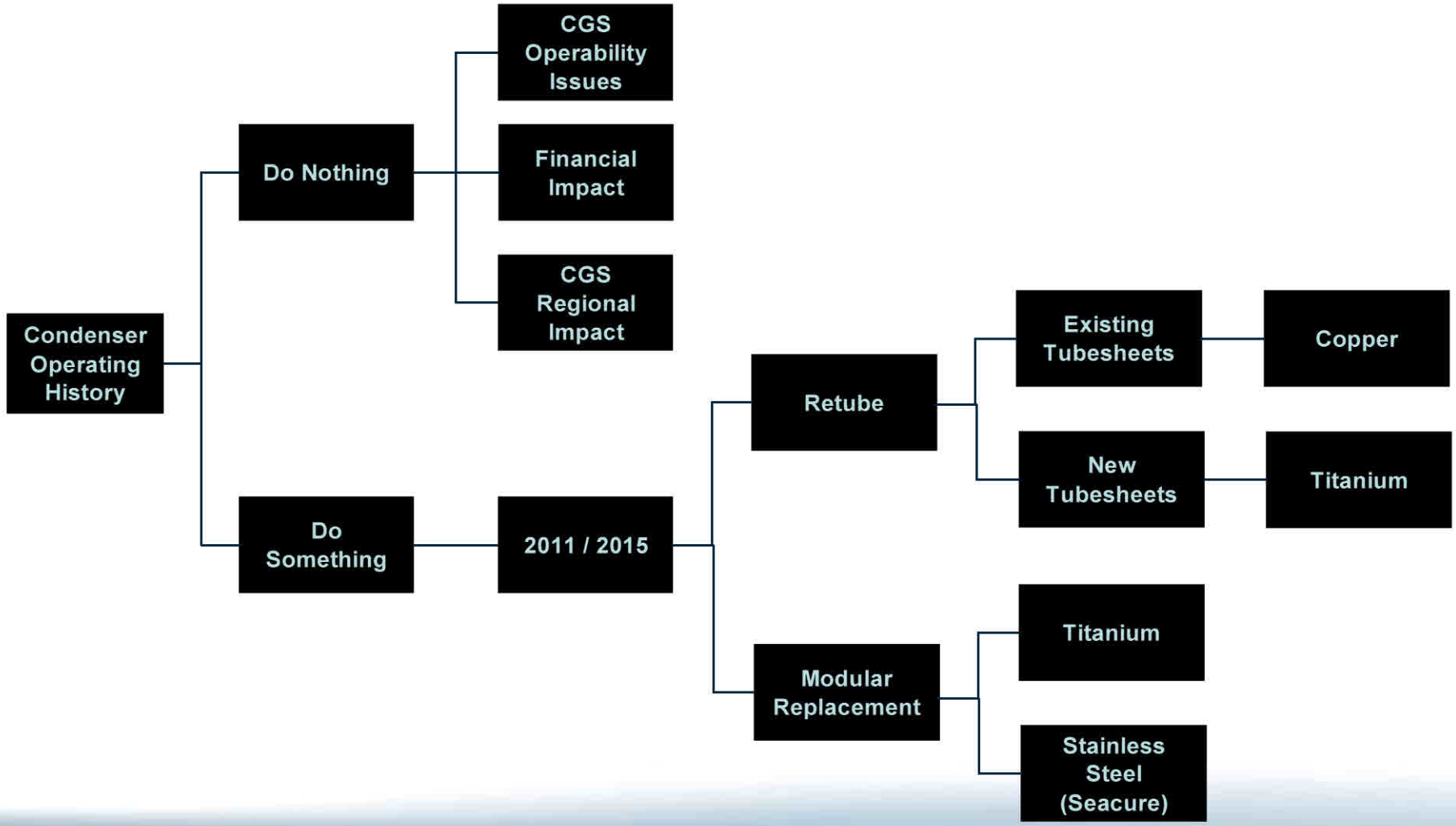
Background - Business Case

Five major issue areas are impacted by Main Condenser performance.

Issue Areas	Summary Observations
Fuel Integrity	• Copper content in the existing condenser tubes poses a continuing risk of fuel cladding damage and fuel failure events.
Radiation Exposure	• Copper from the condenser contributes to increased plant radiation exposure. • Plant downpower evolutions to repair leaking condenser tubes increase radiation exposure. • Copper from the condenser contributes to additional decontamination activities and increases costs. • Potential future litigation due to radiation exposure to workers.
Operational Reliability	• Recurring condenser tube leaks have impacted plant operation and output by forcing downpower evolutions to repair tube leaks.
Financial Implications	• A result of downpower evolutions, forced outages, increased dose, additional decontamination activities, and lost plant generation CGS costs have been adversely impacted.
Industry Perspective	• The potential for fuel damage resulting from copper corrosion is a high interest issue within the nuclear industry and CGS is lagging the industry in this area.

Background - Business Case



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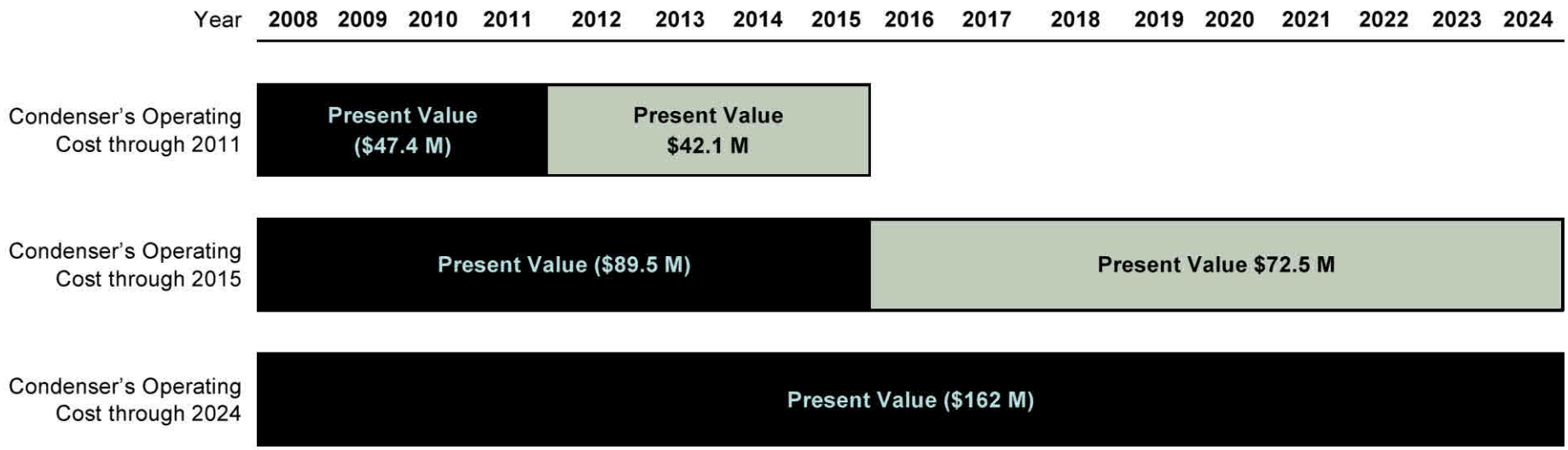
Background – Business Case

Copper Retube Using Existing Tubesheets	Titanium Retube Using New Tubesheets
Stainless Steel (Seacure) Modular Replacement	Titanium Modular Replacement

Background – Business Case

Taking into consideration the operating costs of the current condenser, it is financially beneficial to address the current deficiencies in 2011, the earliest available timeframe to "do something."



(units in PV 2008$ millions; values shown are the expected mean values from Huron analysis)

Based upon the analysis performed, Huron calculates an expected present value of approximately $42.1 M in operating cost savings by implementing a Main Condenser strategy in 2011 versus 2015.

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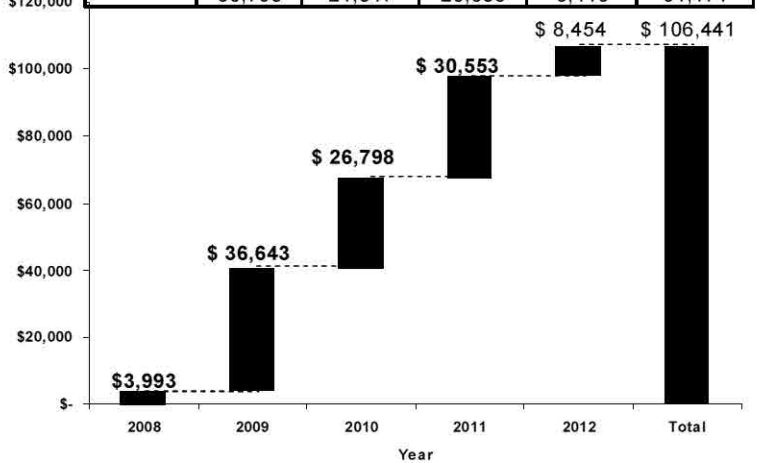
Background - Business Case

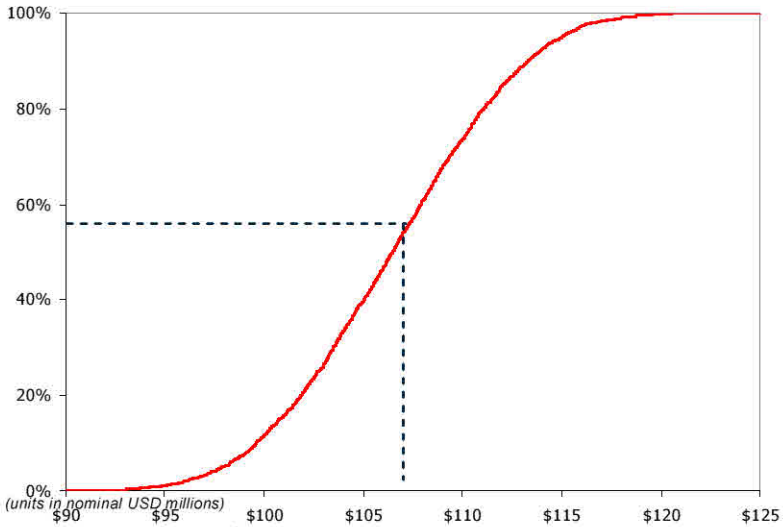
Nominal Cash Flow for Modular Titanium Replacement

	2008	2009	2010	2011	2012	Total
Max	$ 4,769	$ 42,680	$ 31,819	$ 35,260	$ 10,827	$ 122,032
Min	$ 3,212	$ 30,795	$ 21,847	$ 25,685	$ 6,410	$ 91,171

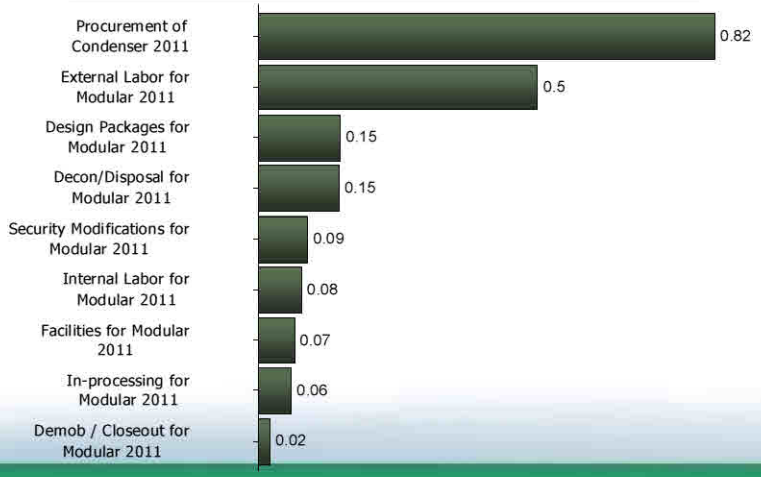


(units in nominal USD thousands; values shown are the mean from Huron analysis)

Total Nominal Cost S-Curve for Modular Titanium Replacement



Tornado Chart for Modular Titanium Replacement



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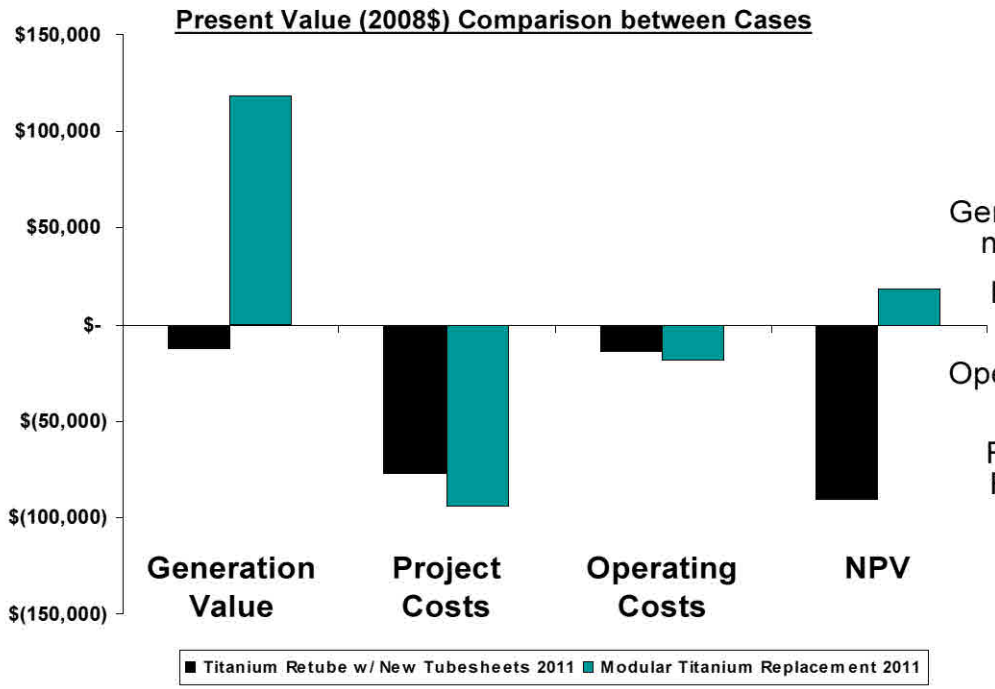
Best Viable Scenario

CGS should perform a Modular Titanium Condenser Replacement during the year 2011 outage.



Comparison of Present Values between both Cases

	Titanium Retube w/ New Tubesheets 2011	Modular Titanium 2011	Delta between cases
Generation Value	$ (12,800)	$ 118,300	$ 131,100
Project Costs	$ (76,706)	$ (93,891)	$ (17,185)
Operating Costs	$ (14,201)	$ (18,900)	$ (4,699)
RFW & RWCU	$ 12,993	$ 13,143	$ 150
NPV	**$ (90,714)**	**$ 18,652**	**$ 109,366**

(units in PV 2008$ USD thousands; values shown are the expected mean values from Huron analysis)

The same outage length is assumed for both cases, although it is possible that the Titanium Retube with New Tubesheets option has an greater risk of longer outage duration due to in-place construction of the new condenser. This requires the perfect "as-building" of >40,000 tube holes.

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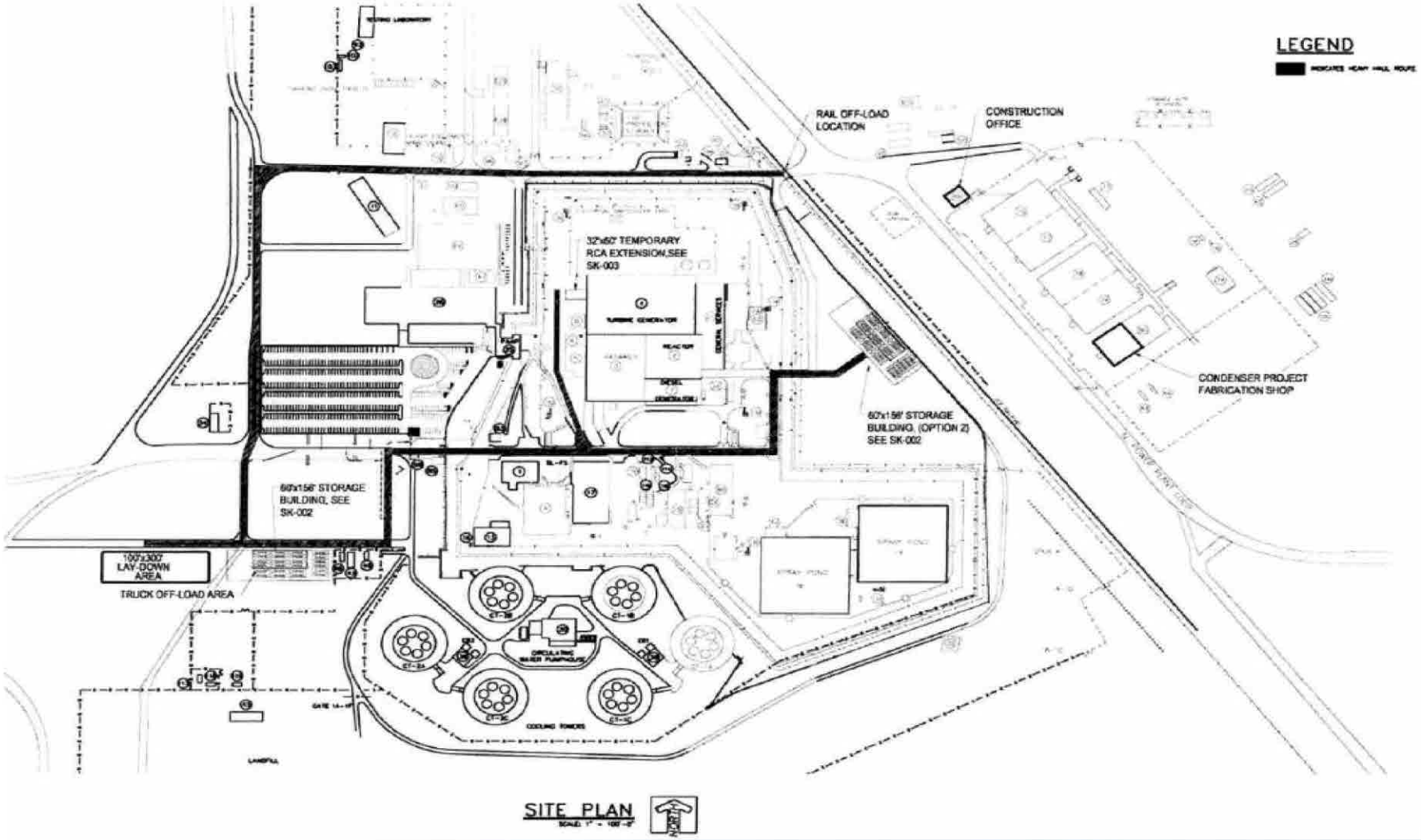
Condenser Project Site Building Plan



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Main Condenser Building Layout

Project Overview –Modules

- Contract awarded on 02-02-09 to Yuba
- Contract consist of:
  - Design of modules, water boxes and bracing
  - Removal and installation instructions
  - 12 modules and 9 water boxes
  - All support bracing material
- First module in the process of being loaded with tubes
- Delivery on track for July 2010

1st Condenser lower module

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Project Overview

R-19 Outage Work Completed – June 2009

- Removable biowall Sections installed on both the west (Column 15) & east (Column 6)
- Relocated Hydrogen Water Chemistry piping and panels outside and inside the Turbine Building
- Six permanent access hatches installed on the condenser walls
- Performance Monitoring Instrumentation installed
- Installed Condenser Wall Stiffeners
- Cleaned the false floor (ceiling of the Hot Well)
- Cleaned the Hot Well

42” bioshield removable west wall

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42” bioshield removal east wall

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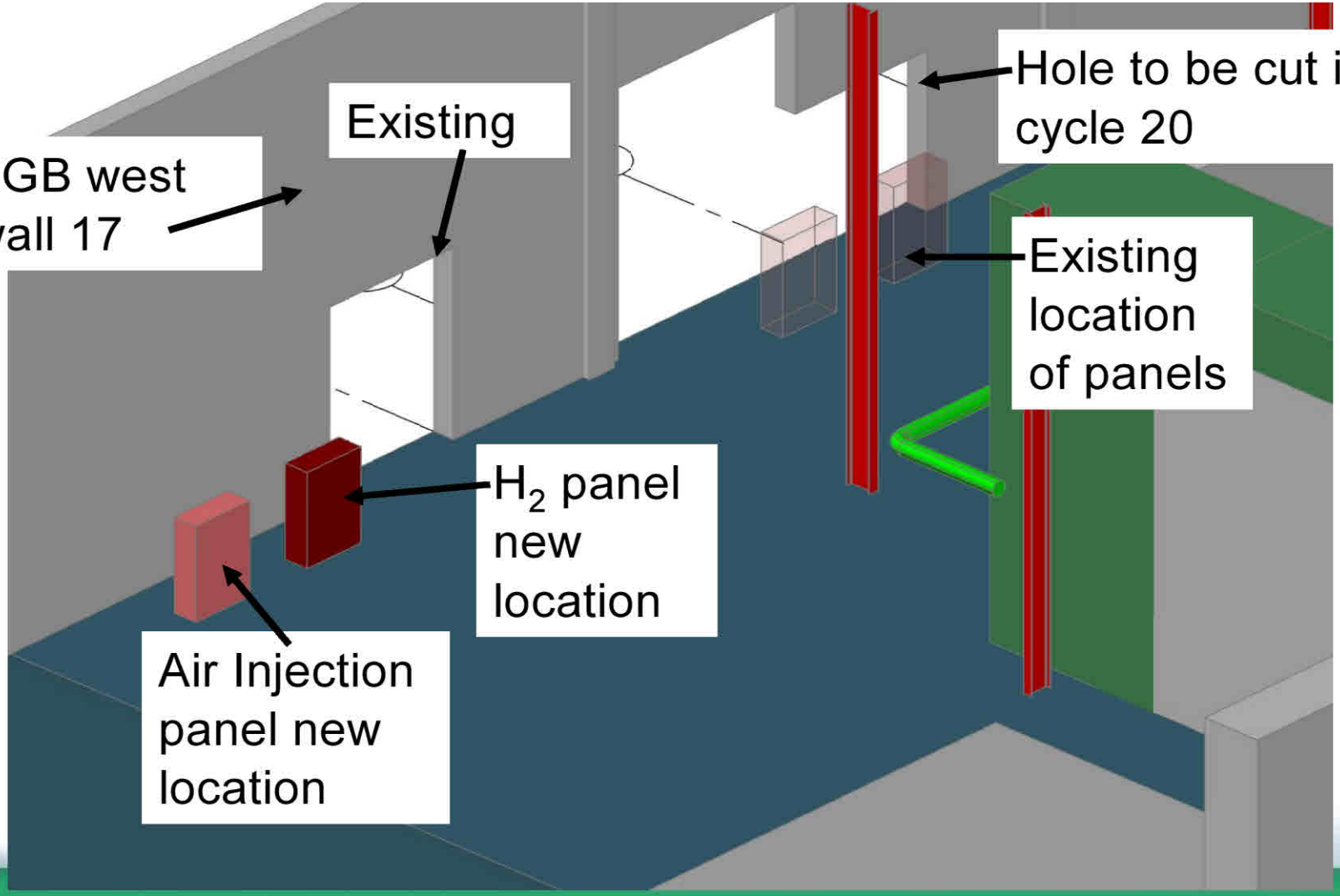
Existing & relocated HWC Panels



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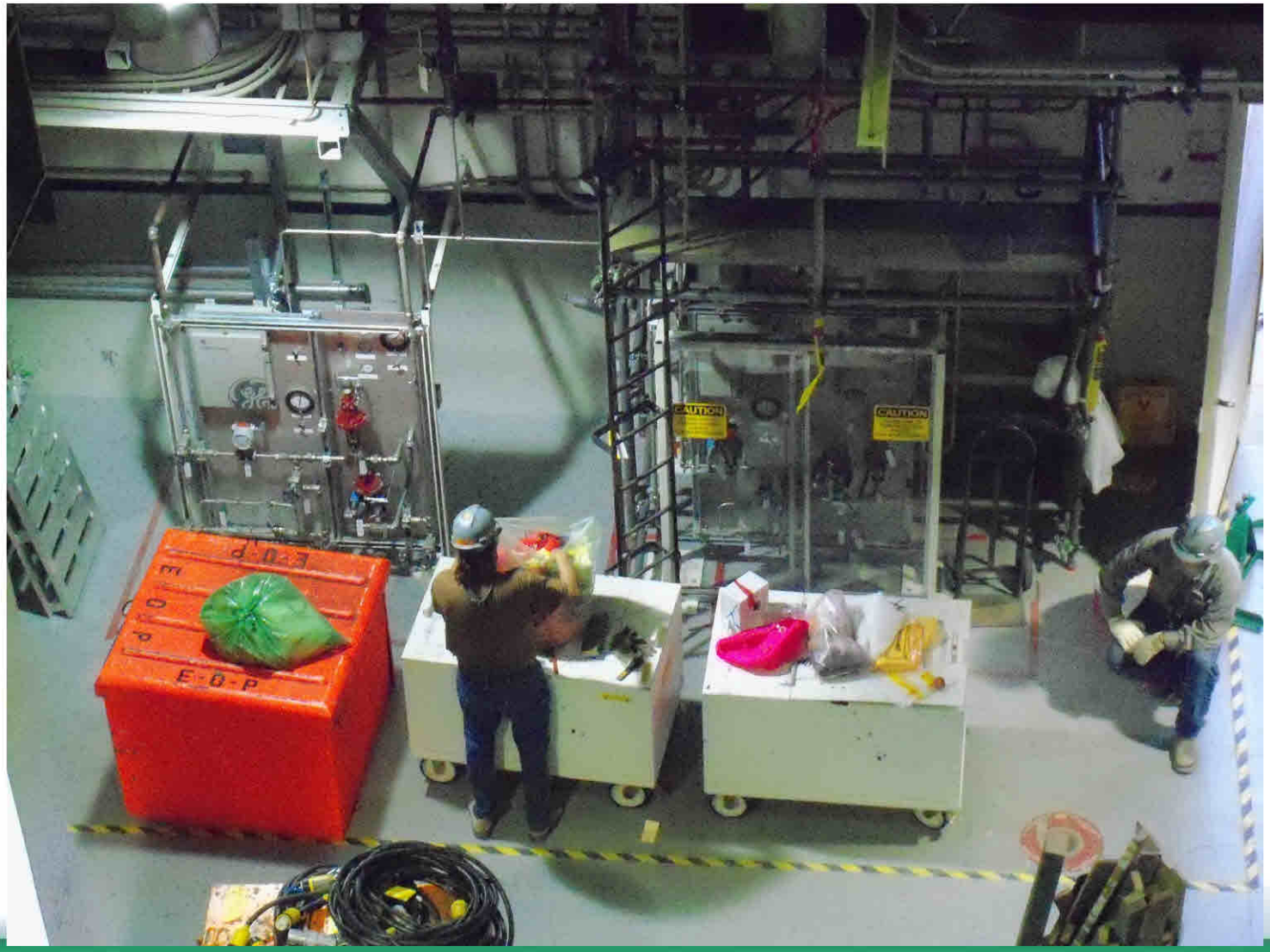
Relocated HWC Panels



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Condenser shell access hatch (6ea)

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Performance Monitoring Instrumentation

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Project Overview-Work in Progress

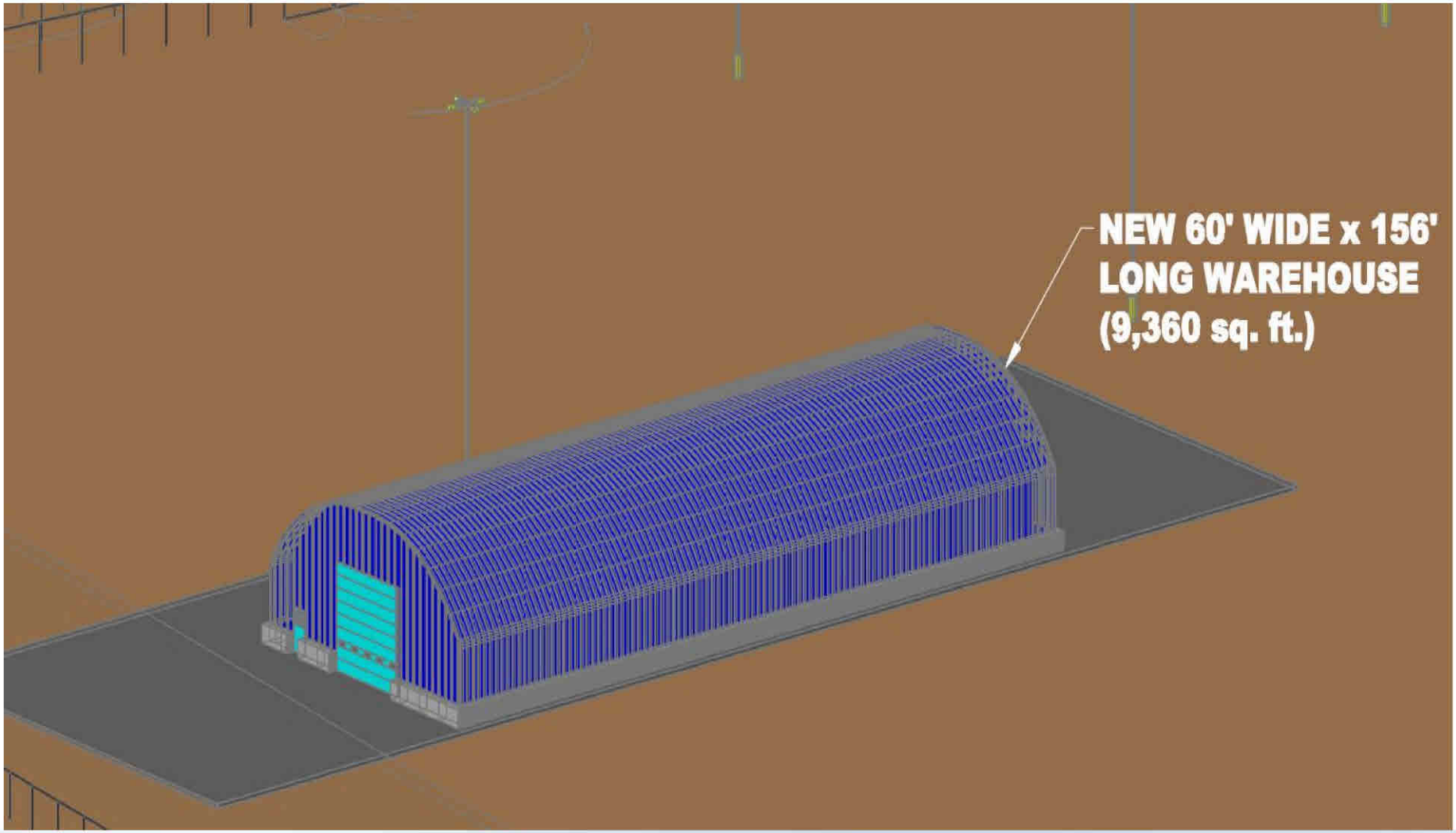
Work in progress:

- Award for R-20 Installation Contract near completion
- Design Engineering is in progress
- Work Order Planning starting after 30% Design complete
- Disposal/recycle plan being developed

Project Overview – Cycle 20 SOW

- Design and install a temporary Condenser Module & Material Storage Building (CM&MSB) for the existing and new condenser module storage area
- Design and install a Temporary Handling Building (THB) on west side of Turbine Building
- Cut and remove exterior wall so access to the THB can be obtained

Condenser Module & Maint Storage Bldg



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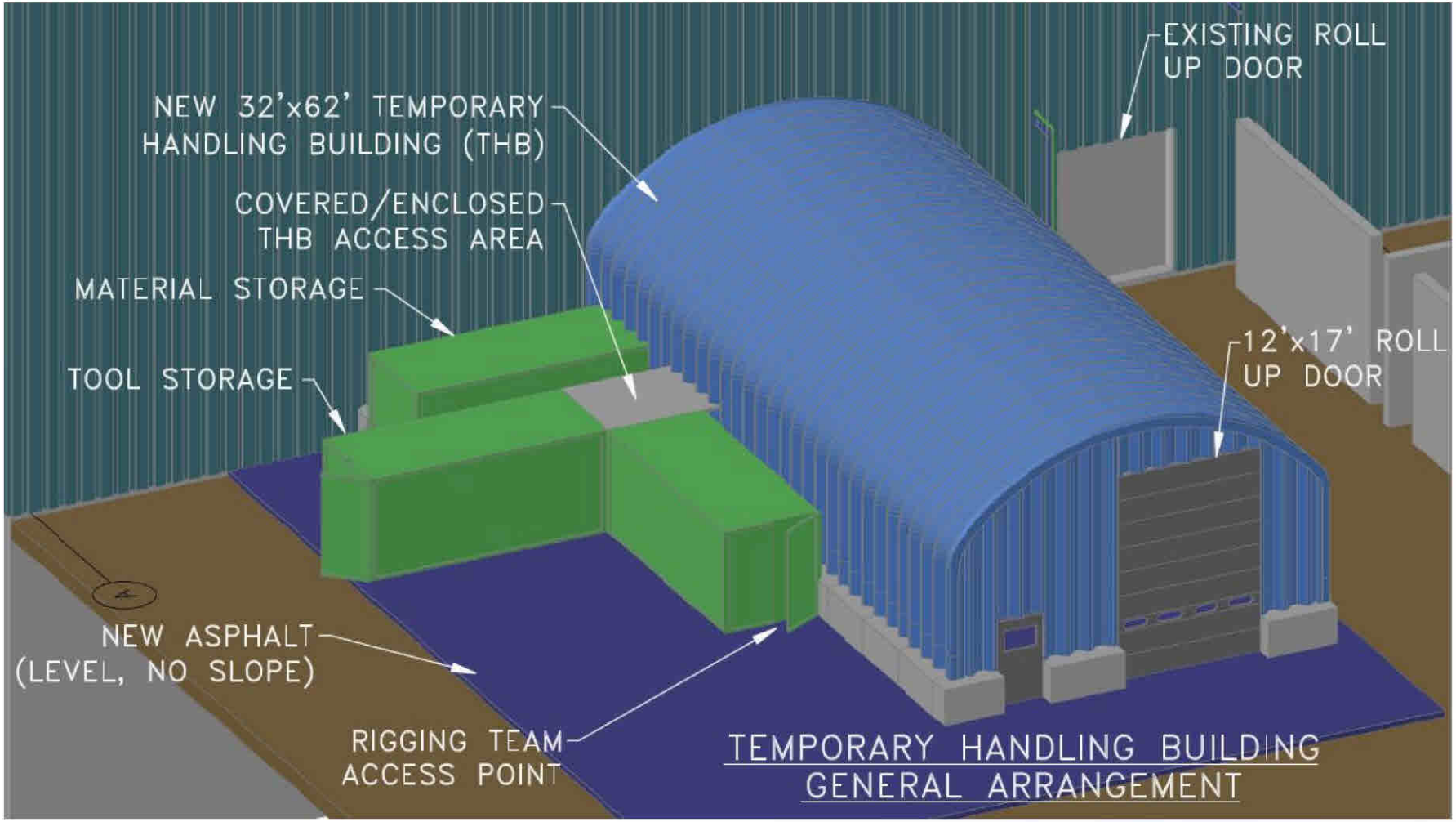
Temporary Handling Building



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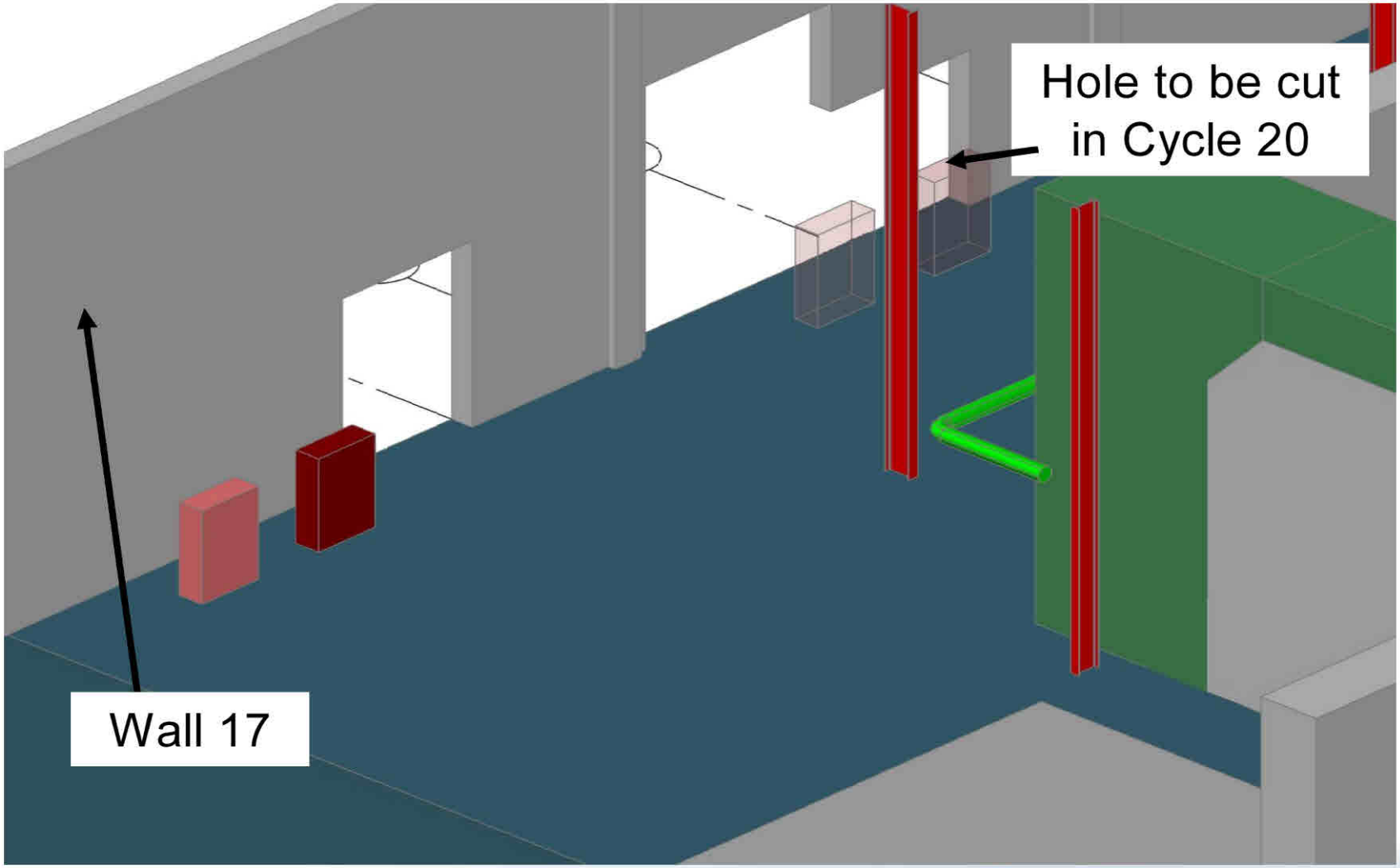
Outside Wall 17



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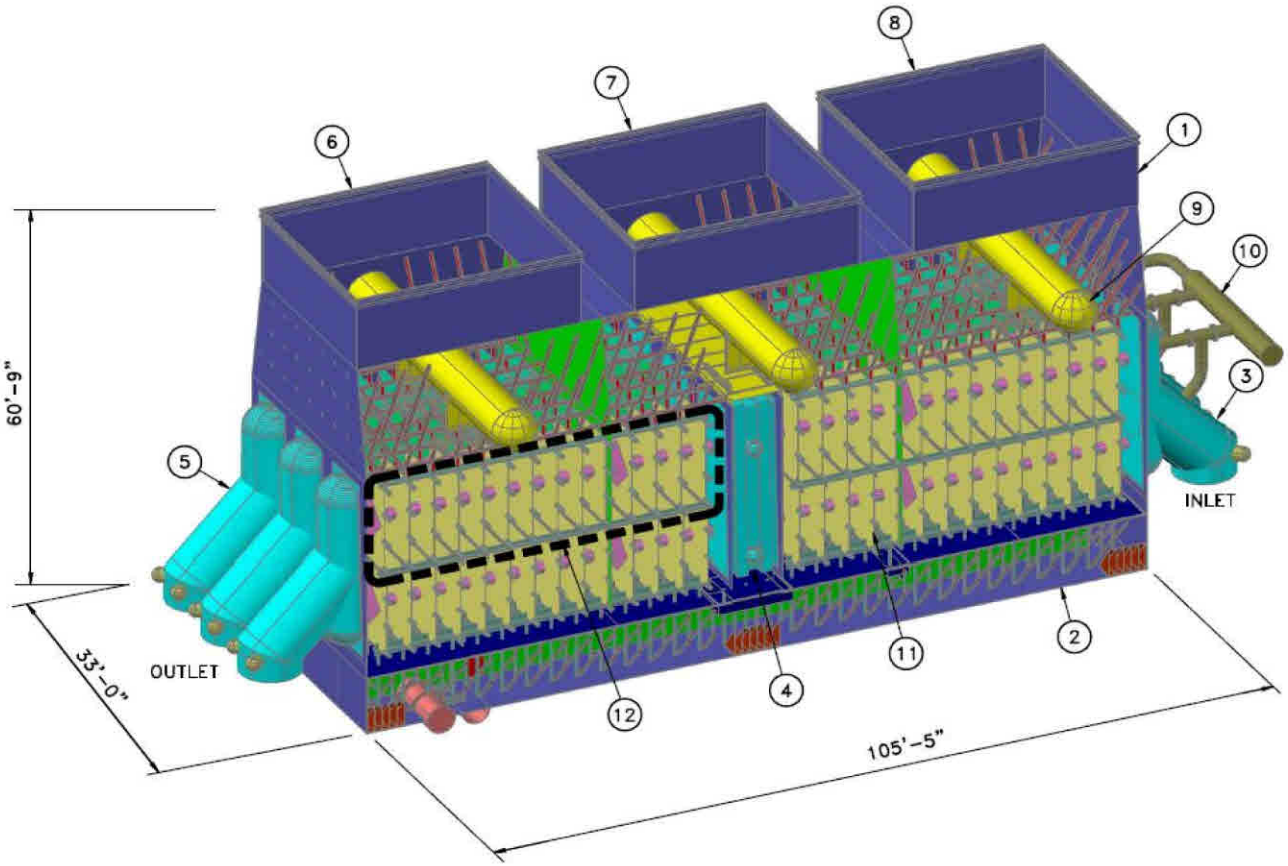
Project Overview-R-20 SCOPE OF WORK

- Remove and replace bioshield block walls
- Remove existing Water Boxes and replace with new Water Boxes
- Remove existing Condenser modules and replace with new Condenser modules
- Modify air removal piping
- Install remaining Performance Monitoring instruments:
  - Install 18 Hard Wire Basket tip pressure instruments on the Condenser Shell
  - Move three temperature gauges and six pressure gauges from the existing water boxes to the new water boxes
  - Install 6 ea flow transmitters on the 72” Circ Water Risers in the Cooling Tower Area
- Replace 100 vertical Hot Well Supports
- Modify 23 Heater Drain Valve penetrations

R-20 Work - Modules

MAIN CONDENSER



1. CONDENSER SHELL
2. HOTWELL
3. INLET WATERBOXES
4. INTERMEDIATE WATERBOXES
5. OUTLET WATERBOXES
6. L.P. TURBINE EXHAUST NECK 1-C
7. L.P. TURBINE EXHAUST NECK 1-B
8. L.P. TURBINE EXHAUST NECK 1-A
9. FEEDWATER HEATER 1-A
10. AIR REMOVAL PIPING
11. TUBE SUPPORT PLATE
12. CONDENSER MODULE (1 OF 12)

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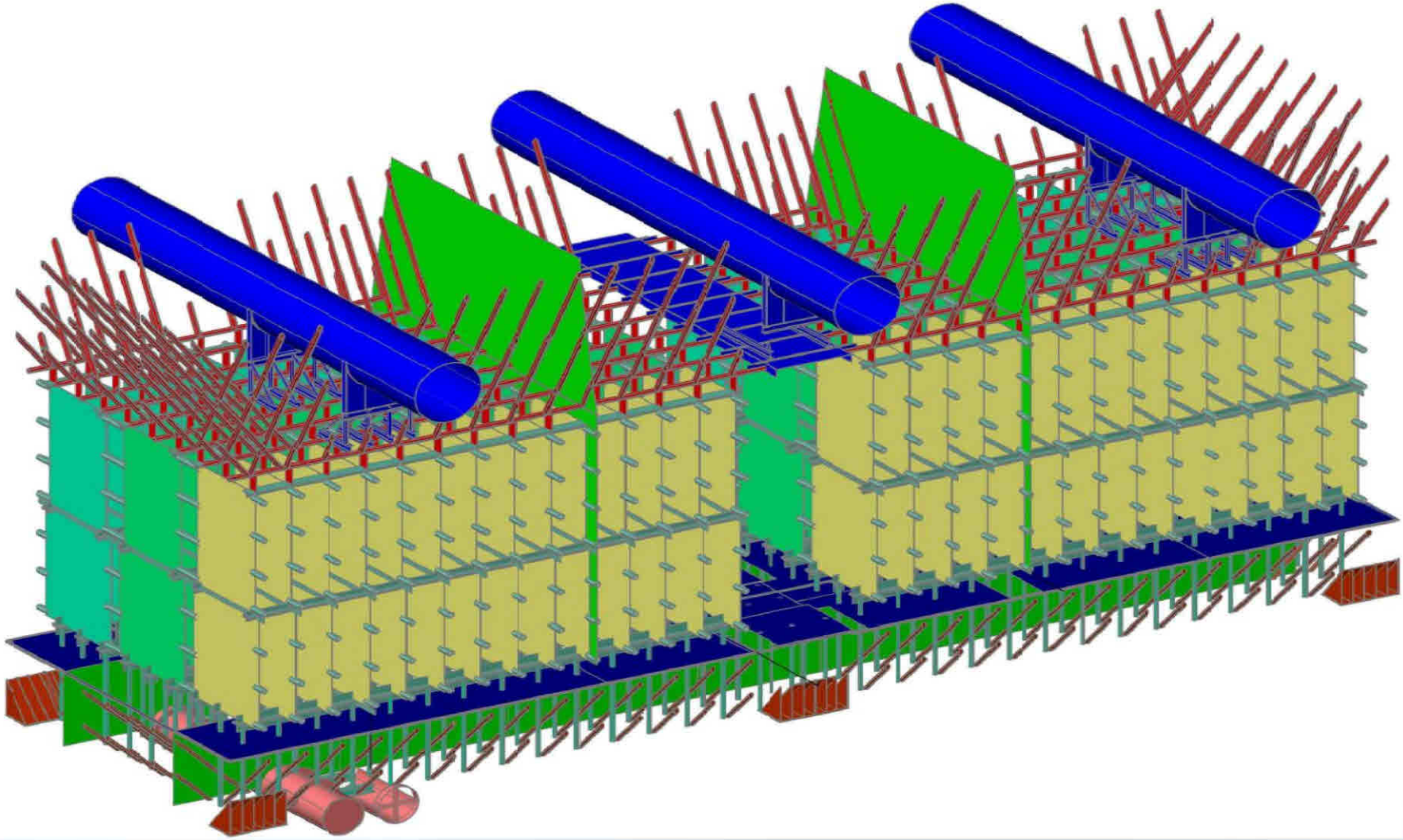
Condenser Modules & Supports



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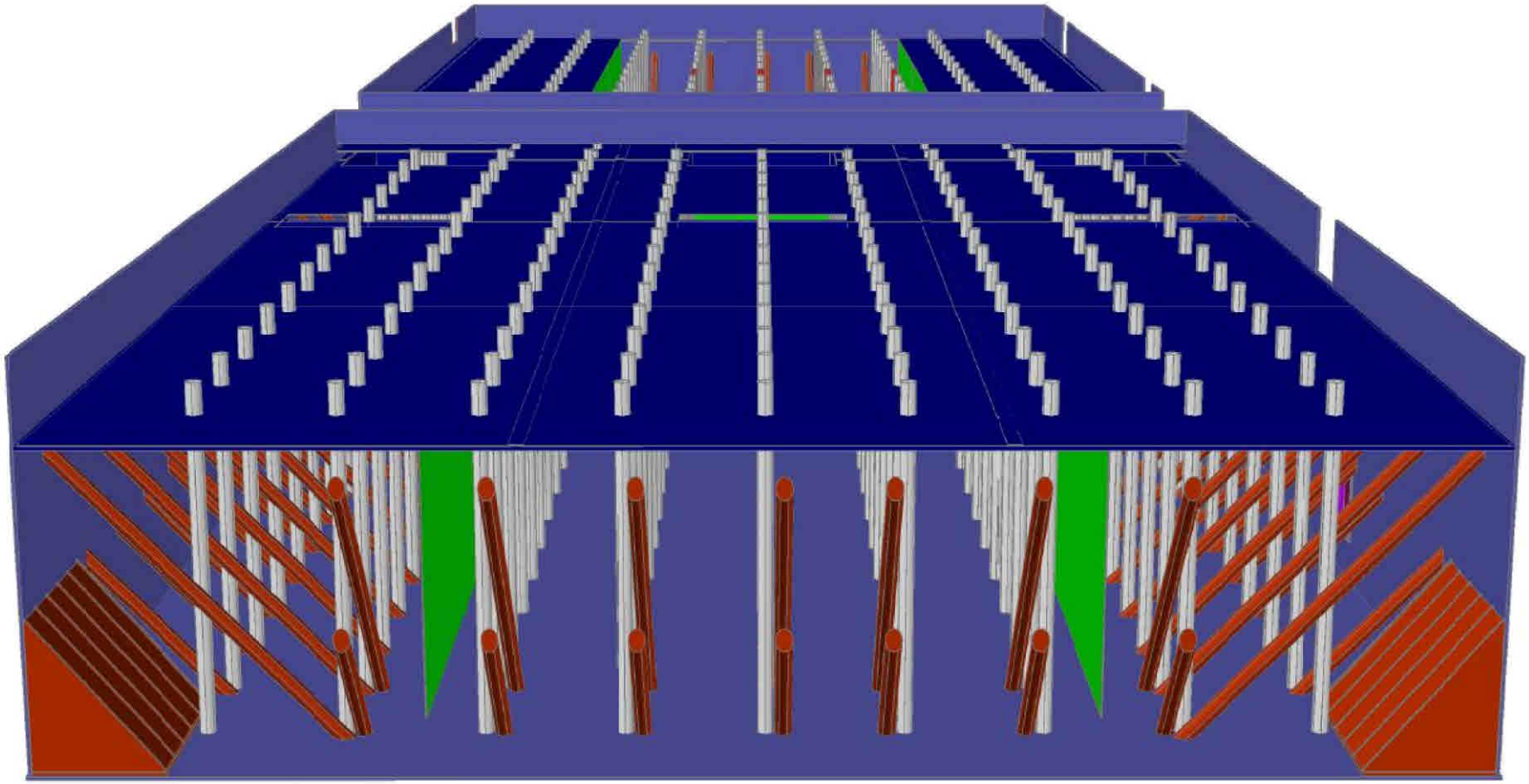
REPL AREA FOR HOTWELL SUPPORTS



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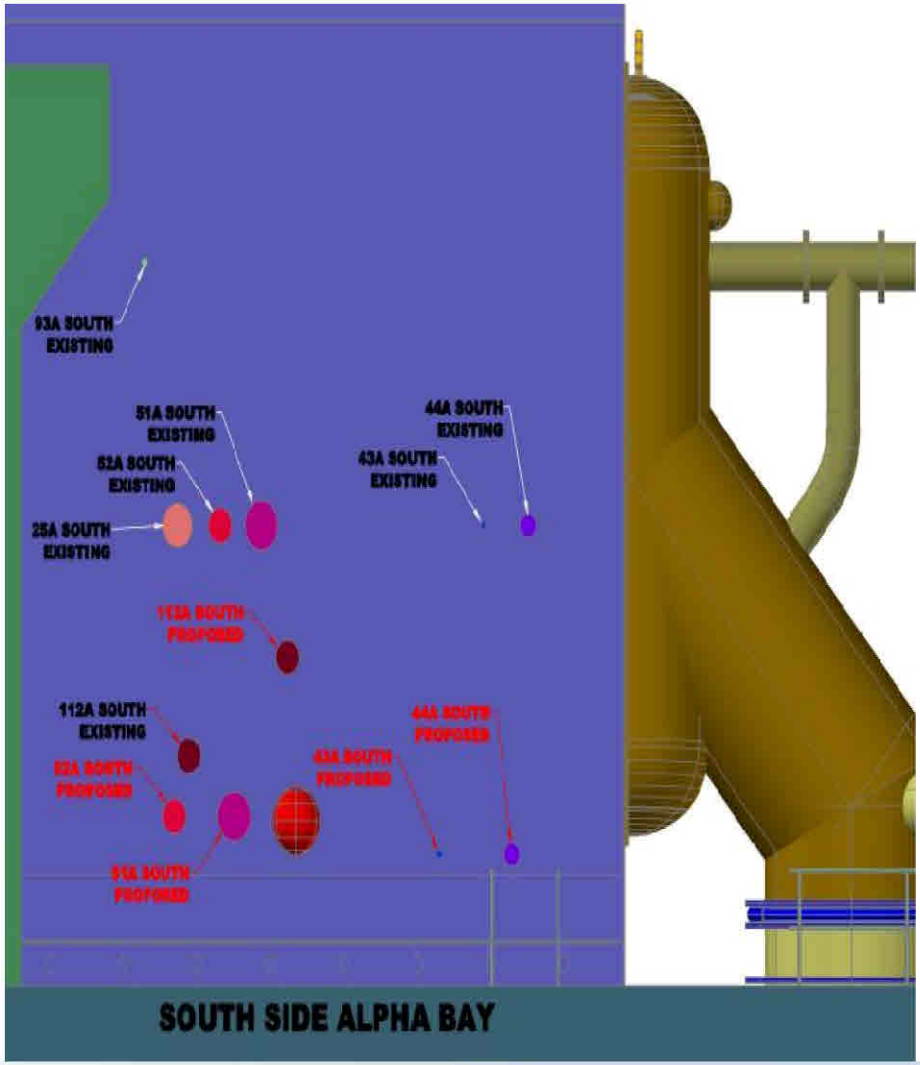
Typical HD&V Piping Relocations



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What Does Success Look Like

- Project industrial safety goals met
- Quality / Error Free performance the 1st time
- **No negative impact on the operation of the plant (during startup and/or cycle 21) due to condenser replacement**
- Condenser replacement duration minimized for R-20 outage achieving the following:
  - Condenser installed on schedule
  - Project maintained within budget
  - ALARA dose goals achieved
- Obtain expected electrical output increases (MWe)

How is the Project Assuring Success

- Extensive involvement with R-20 Installation bidding contractors prior to contract award
  - **Identified the need in the RFP for combined company safety record to be identified**
  - Criteria for bid evaluation gives credit for good OSHA and L&I safety records.
  - Requested contractor to submit for review and approval their safety plan or 100% compliance with Energy Northwest Safety procedures
  - Safety Representative oversight during the R-20 outage on every shift

How is the Project Assuring Success

- **Incorporating lessons Learned from R-19 and before**
- Incorporating Lessons Learned from benchmarking other plants and INPO Operating Experience
- Met the Module Manufacturer and bidding contractors at manufacturer's facility to discuss removal and installation to minimize installation challenges
- **Bidding contractors walked down condenser internals during R-19 Outage to understand the complexity of work**
- **Energy Northwest Engineering and Industry Subject Matter Experts review and approval of Condenser Module Design**
- Extensive benchmarking on condenser design will produce superior performance

How is the Project Assuring Success

- **100% Energy Northwest condenser module manufacturing oversight**
- Goal of Zero Tube damage during transport and installation by use of FME protection. (Plywood sheeting / tarp coverings)
- Redesign of all high steam impingement impact points on existing condenser placing the nozzles below tube sheets and adding spargers to disperse steam
- **Redesign of the Air removal system increases efficiency of condenser**
- Each condenser module and other large components will have a rider accompanying the load to assure shipping is performed without unknown damage
- **Energy Northwest oversight of R-20 Installation Contractor assures quality planning and implementation**

How is the Project Assuring Success

- **Site Engagement by Teaming with other Plant Organizations using one team one goal approach**
  - Identification of other R-20 work that will impact critical path R-20
  - Work with Outage Management & PRC to reduce the impact of other R-20 work that could impact critical path
  - Integrated scaffolding plan with Maintenance and Radiation Protection for the Turbine Building
  - Integrating Radiation Protection processes into the project plan
  - Identification of R-20 Installation Cost and Disposal Cost
- Monitor progress of Project with an approved Work Breakdown Structure Schedule utilizing Schedule Performance Index
- **Monitor cost of project utilizing Cost Performance Index**

How is the Project Assuring Success

- System interface being analyzed in Plant Design Change to install new condenser to verify no unintended consequences exist
- Dedicated Health Physic technicians assigned during R-20 Outage with Project/Contractor Radiation Protection Coordinators to assure ALARA
- **Installation of a performance monitoring system to verify Megawatt increase contract agreement with condenser module manufacturer was satisfied**
- **Post Modification Testing of the Installation contractor using a vacuum pull test to detect leaks**

Risk Identification and Monitoring

- Identification of risks has been completed
- Owners have been identified
- Monitoring plans in process of being developed
- Risk statements incorporated project assumptions developed during the Request for Proposal process
  - Contractor provided their assumptions which were incorporated into the RFP or turned into risk statements
- Project contingencies also identified
- Controlling general work in Turbine Building will protect condenser critical path work
  - Based on lessons learned from R-19
  - Teaming with other organizations in progress

Plans to Ensure Reliability

- 100% Energy Northwest oversight of module manufacturing
- On-site Energy Northwest Project Team oversight of Installation Contractor
- Vacuum test to verify system Is leak tight
- Performance monitoring test verifying all operating parameters by manufacturing vendor have been satisfied

Plans to Ensure Reliability

- High pressure steam dumps re-routed below the condenser modules
- Instrumentation to monitor performance of the condenser to detect issues on line
- B water box entry capabilities so leaking tubes can be plugged at 60% power
- Procedures implemented to protect condenser tubes during future refueling outages for the life of the plant

Questions/Comments?

Progress Report on ACPRT Review
CGS Condenser Replacement

The Agency Capital Project Review Team (ACPRT) is reviewing the business value of Energy Northwest (ENW)'s condenser replacement project for BPA. The review is focused on the financial implications of four alternatives that were considered in a Huron Consulting Group study commissioned last winter by ENW:

1. Titanium modular replacement installed in 2011;
2. Titanium modular replacement in 2015;
3. Titanium retube with new tubesheets in 2011; and
4. Titanium retube with new tubesheets in 2015.

The Huron Study concluded that the Titanium modular replacement – 2011 alternative was preferable because it offered greater technical and operational benefits than the titanium retube alternative and because it was financially advantageous to proceed sooner rather than later. ENW included the modular replacement – 2011 alternative in its FY 2009 budget, which the ENW Board approved and BPA non-disapproved in late spring 2008. This alternative is also reflected in the spending levels that BPA proposed in the Integrated Program Review.

The Huron Study process was largely closed to BPA and other stakeholder review until it was completed in February 2008. The Study's analytical approach, assumptions, and results were documented, however, and the Study serves as the primary source of financial data for the ACPRT's review. Huron evaluated the financial costs and benefits of the alternatives using the same life cycle costing/net present value method that Bonneville now uses to evaluate other capital projects. At the Administrator's direction, the review is being conducted with currently available materials; no request has been made for supplemental information from ENW or Huron, and no business case was requested or submitted. PGC is a full partner in the review.

We anticipate completing the review by the first week in August. Power Services will be briefed and comments considered before findings are advanced to the CAB. The ACPRT's report will cover the (1) financial and risk implications of the project alternatives and (2) a high-level assessment of ENW's capital decision practices with regards to BPA's asset strategy and standards for capital project valuation.

The ACPRT has replicated the financial analytics performed by Huron, and issues have been found that affect the calculation of net present values for the four alternatives. For example:

- The discount rate that Huron used to determine the net present value of the alternatives was 6.5 percent (reflecting ENW's weighted average cost of capital), rather than the 13 percent risk-adjusted discount rate that BPA has established for Federal hydro and other capital projects in Power Services.
- Incremental cash flows for each alternative were not developed by comparison to a reference, or "no action" case. All other things equal, the net effect of this is that long-term benefits were overstated
- Replacement power costs (due to lost generation) and savings were not fully accounted for, nor was replacement power cost uncertainty.

We are re-running the analytics now, and offer no findings or conclusions at this point.

1/26/06

EXECUTIVE BOARD
RESOLUTION NO. 1423

A RESOLUTION APPROVING THE 2006 ENERGY NORTHWEST REFUNDING PLAN FOR PROJECT 1, COLUMBIA GENERATING STATION, AND PROJECT 3 AND EXTENDING COLUMBIA GENERATING STATION DEBT

The Chief Executive Officer reports that by Executive Board Resolution No. 1207, adopted September 27, 2001, the Executive Board approved the Energy Northwest September 2001 Refinancing Program, comprised of the refinancing of Project 1, Columbia Generating Station (Columbia), and Project 3 Bonds, and delegated certain responsibilities to Energy Northwest's Chief Executive Officer and Chief Financial Officer in connection with that program, and

The Chief Executive Officer further reports that the September 2001 Refinancing Program detailed the goals and objectives of the Refinancing Program implemented by Energy Northwest and the Bonneville Power Administration (BPA). That Refinancing Program contains the historical debt service savings goals and objectives for Callable Refunding Candidate Bonds and also contains the Debt Optimization Program description and objectives. The 2006 Refunding Plan reaffirms the above sections and proposes that the final maturity of Columbia debt be extended from 2018 to 2024, and

Based upon the recommendation of the staff and the Chief Executive Officer, the Executive Board finds that approval of the 2006 Refunding Plan, the reaffirmation of the authorities granted in Executive Board Resolution No. 1207, and the proposal that the final maturity of Columbia debt be extended from 2018 to 2024 are in the best interests of Energy Northwest and the electric ratepayers of the Pacific Northwest; NOW, THEREFORE,

IT IS RESOLVED that the Executive Board approves the 2006 Refunding Plan, reaffirms the authorities granted in Executive Board Resolution No. 1207, and approves the proposal that the final maturity of Columbia debt be extended from 2018 to 2024 in the following circumstances:

1. For new capital investments to their useful life up to 2024;

2. For the Columbia Debt Optimization Program debt in Fiscal Year 2006 of $105 million; and

3. For the Columbia callable/advance refundable debt in Fiscal Year 2006 of $350 million.

It is further resolved that the above approval is subject to the following conditions:

1. That adequate funding for Columbia license extension be provided for in the 2007-2009 BPA rate proposal as agreed to by Energy Northwest management;

2. That a joint BPA-Energy Northwest taskforce be created to address deferred maintenance issues for Columbia. A plan shall be prepared which addresses the implementation of necessary equipment upgrades and replacements, including but not limited to condenser replacement, feedwater heaters, and the digital electro hydraulic control system. The plan shall include a goal to minimize impacts to ratepayers both near and long-term. Such plan shall rely first on savings achieved by Energy Northwest activities and may include long-term debt financing if necessary; and

3. The taskforce shall proceed immediately and finalize its report to the Executive Board and other interested parties as soon as possible;

and the Chief Executive Officer, or his designee, is authorized and directed to take such actions as necessary to implement these actions, subject only to the contractual rights of the Bonneville Power Administration and the Participants' Review Board.

ADOPTED by the Executive Board of Energy Northwest this 26th day of January, 2006.

Chairman

ATTEST:

Secretary

APPROVED AS TO FORM AND LEGALITY:

Counsel

EXECUTIVE BOARD

RESOLUTION NO. 1445

A RESOLUTION WITH RESPECT TO PLANT LIFE EXTENSION AND EQUIPMENT RELIABILITY – COLUMBIA GENERATING STATION

Whereas, the working relationship between Energy Northwest's (EN) Columbia Generating Station (CGS) and the Bonneville Power Administration (BPA) requires the highest levels of cooperation and coordination, and

Whereas, the recent successful extension of BPA's Debt Optimization Program included a commitment to the Participants Review Board, the Board of Directors, and the Executive Board that essential CGS life-extending investments would be made as scheduled by EN management, and

Whereas, condenser replacement is a vital element of plant life extension and equipment reliability, with condenser tube leaks leading to reduced power, lost generation revenue, engineering and repair costs, and increased radiation exposure to workers, and

Whereas, national regulators and evaluators have grown weary of the CGS delay in replacing condenser tubes that goes back to the 2003 budget request and further delay will result in negative findings, future safety and reliability risks, and potential damage to the reactor's components, and

Whereas, the Executive Board is questioning BPA's potential influence through budget uncertainty over what is clearly a nuclear reliability and safety issue; NOW, THEREFORE,

IT IS RESOLVED that the Executive Board of Energy Northwest insist on all parties keeping commitments on plant life extension investments as well as the extension of debt, with special emphasis on replacement of the trouble-plagued condenser.

ADOPTED by the Executive Board of Energy Northwest this 27th day of April, 2006.

Chairman

ATTEST:

Secretary

APPROVED AS TO FORM AND LEGALITY:

Counsel

ENERGY NORTHWEST

Condenser Replacement Project Steering Committee Meeting

Project No. 00608601

May 8, 2008

Brian Berglin

Agenda

- Follow up from 04-07-08 Meeting — Berglin
- Project Status — Berglin
- Help/Decisions Needed — Smalldridge
- What does success look like — Swank
- Open Discussion & Action Summary — All

Follow up Actions from 04-07-08

- Project Goals – What does success look like – Swank — Complete – next week.
- Condenser Project Organization Code – Reed — Complete → Denied
- Updated FY08-FY12 Schedule-Lovejoy – Level 1 schedule — Handout
- Reduction of R-20 Outage Duration-Lovejoy/Mossey — Handout
- Detailed FY08&FY09 Design Cost-Jordan — Handout
- Relief Valve Testing Room re-location-Racine — In-Prog.
- R-19 Outage Schedule Break-down-Lovejoy — Handout
- Establish Source Evaluation Panel & Contract Review Board personnel — Complete

to make sure everyday's condenser work fits in – integrated effort → so people aren't bumping into each other.

how to go in to condenser bay on east side, so need to move this room. 380k to move to 471

– Can we send valves off for one or two years?

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Project Status (Recent Accomplishment)

- Project Scoping Document
- Fast Track Outage Milestones are near completion
  - Engineering 12-18-08 (Proposed & Preliminary agreed to)
  - Work Orders 95% 02-12-08 (Proposed & Preliminary agreed to)
- R-19 Design work is in-progress & on Schedule
- R-19 Planning
  - Planning for HIT is 87% complete on Status 25
  - Project Planning is in progress with Design Work
  - All Work Orders identified for R-19 Outage
- Condenser Specification Rev A
- RFP draft completed for Condenser Module Procurement
- RFP for Design and Installation contract is near completion
- Project Team Risk Assessments are near completion

Project Status (Issues/Decisons)

R-19 Condenser Design & Implementation Issues/Decisions (Risk Assessments)			
Major Decisions	DATES		
	Due	Complete	Responsible
One high/Two High Module Removal/Install through west side	01/31/08	1/31/2008	Bickford/Mossey
Re-coating of Water Boxes	03/28-08	3/28/2008	Woods/Catlow
East side Access through Bio wall	04/03/08	4/3/2008	Racine/Mossey
Removal of East Water boxes	04/03/08	4/3/2008	Racine/Mossey
PTC-12.2 Performance Monitoring Instrumentation scope	4/16/2008	04/16/08	Grier/Woods
Defining cuts in West Turbine Building Walls (Bio & Exterior)	4/16/2008	04/16/08	Mossey/Racine
Risk Assessment of removal method of condenser modules	05/02/08	05/02/08	Thiederman
Hotwell Temporary Access Areas	05/06/08	05/06/08	Mossey/Racine
441'/471' Condenser Permanent Access Areas	05/06/08	05/06/08	Mossey/Racine
Relief Valve Room relocation/limited use plan for R-19 and R-20	05/09/08		Garza/Racine/Mongomery/Hoyle
Rigging Plan Conceptual Design	05/30/08		Jim Paulsen (Barnhart)
Can hot well floor supports support both rail system orientations	TBD		Grier/Malinski

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Near Term Milestones

Relief Valve Room Re-location	05-09-08/Racine/Garza
Condenser Project Special Outage Milestones	05-15-08/Lovejoy)
Develop a Communication Plan	(05-15-08/Thiederman)
RFP for Condenser Module Fabrication Issued	(05-23-08/Korenko)
RFP for Design & Installation issued	(05-23-08/Berglin/Whelan)
Receive Bottoms up estimate	(05-30-08/S&L)
Develop a Procurement Plan	(05-30-08/Whelan)
Re-baseline FY09 Project Schedule	(06-03-08/Jordan)
Receive Bottoms up estimate	(06-08-08/S&L)
Rev 0 Condenser Spec approval	(06-11-08/Korenko)
Set up a Benchmark trip to Laguna Verde	(06-15-08/Berglin)
Hold Project Kick Off meeting with Stakeholders	(06-18-08/Berglin)
East Condenser bay access contract change	(TBD/Whelan-Grier)
Develop a R-19 Hotwell Cleanup Schedule	(TBD/Lovejoy)

FY08 Project Budget

Description	EAC
Scoping	$640,000
Project Management & Project Controls	$579,180
Design and System Engineering	$534,219
R-19 Designs	$1,099,982
Independent Contractors & Consultant	$125,000
Module Procurement	$256,300
Planning & Coordination	$127,140
R-19 Installation	
EN SSC & Other Pre Outage and Outage Support	$17,630
Facilities	$289,526
Administration & Taxes	$141,200
Incentives	
Non ENL FY08 Total	$3,810,177
ENL	$200,000
With ENL Total	$4,010,177

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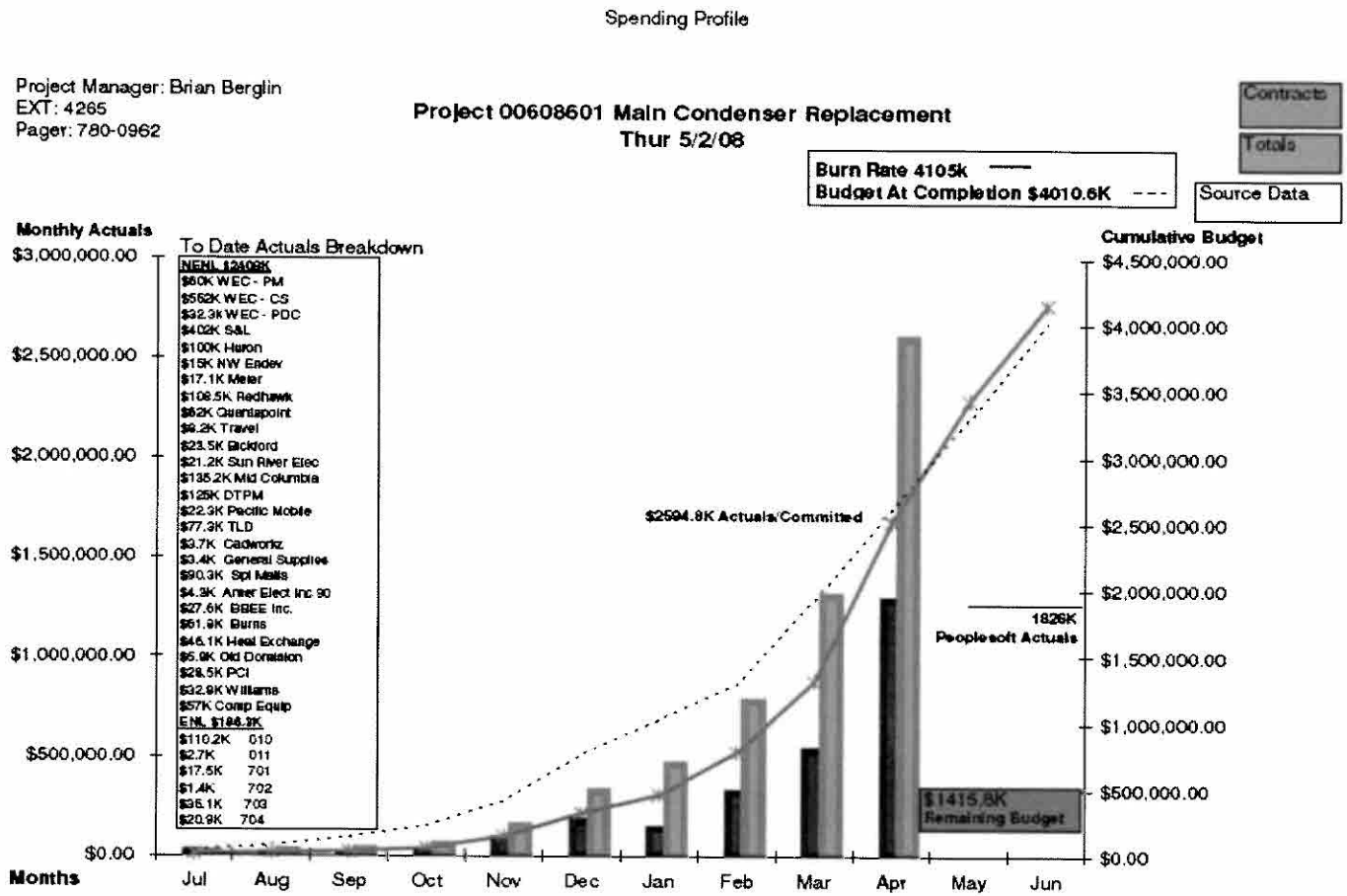
FY08 Current & Expected Costs



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FY09 Project Budget

Description	FY09				
	PHC	EAC	EAC(2nd)	Delta	Risks
Scoping	$0	$0	**$0**	$0	
Project Management & Project Controls	$1,169,660	$1,169,660	**$968,060**	$201,600	Medium
Design and System Engineering	$1,928,321	$1,599,101	**$960,670**	$638,431	Low/Medium
R-19 Designs	$3,357,099	$3,107,077	**$2,807,077**	$300,000	Medium/High
Independent Contractors & Consultant	$291,400	$291,400	**$90,400**	$201,000	Medium
Module Procurement	$2,584,360	$2,584,360	**$2,434,360**	$150,000	Low/Medium
Planning & Coordination	$1,361,122	$1,361,122	**$1,027,688**	$333,434	Medium
R-19 Installation	$8,950,883	$5,705,883	**$5,705,883**	$0	
EN SSC & Other Pre Outage and Outage Support	$1,588,734	$1,588,734	**$1,498,734**	$90,000	Medium
Facilities	$1,075,456	$1,075,456	**$649,056**	$426,400	High
Administration & Taxes	$2,315,188	$1,001,055	**$921,055**	$80,000	
Incentives	$429,000	$429,000	**$0**	$429,000	Medium/High
				$0	
Non ENL FY08 Total	$25,051,223	$19,912,848	$17,062,983	$2,849,865	
ENL	$174,720	$174,720	**$655,358**	($480,638)	
With ENL Total	$25,225,943	$20,087,568	**$17,718,341**	$2,369,227	

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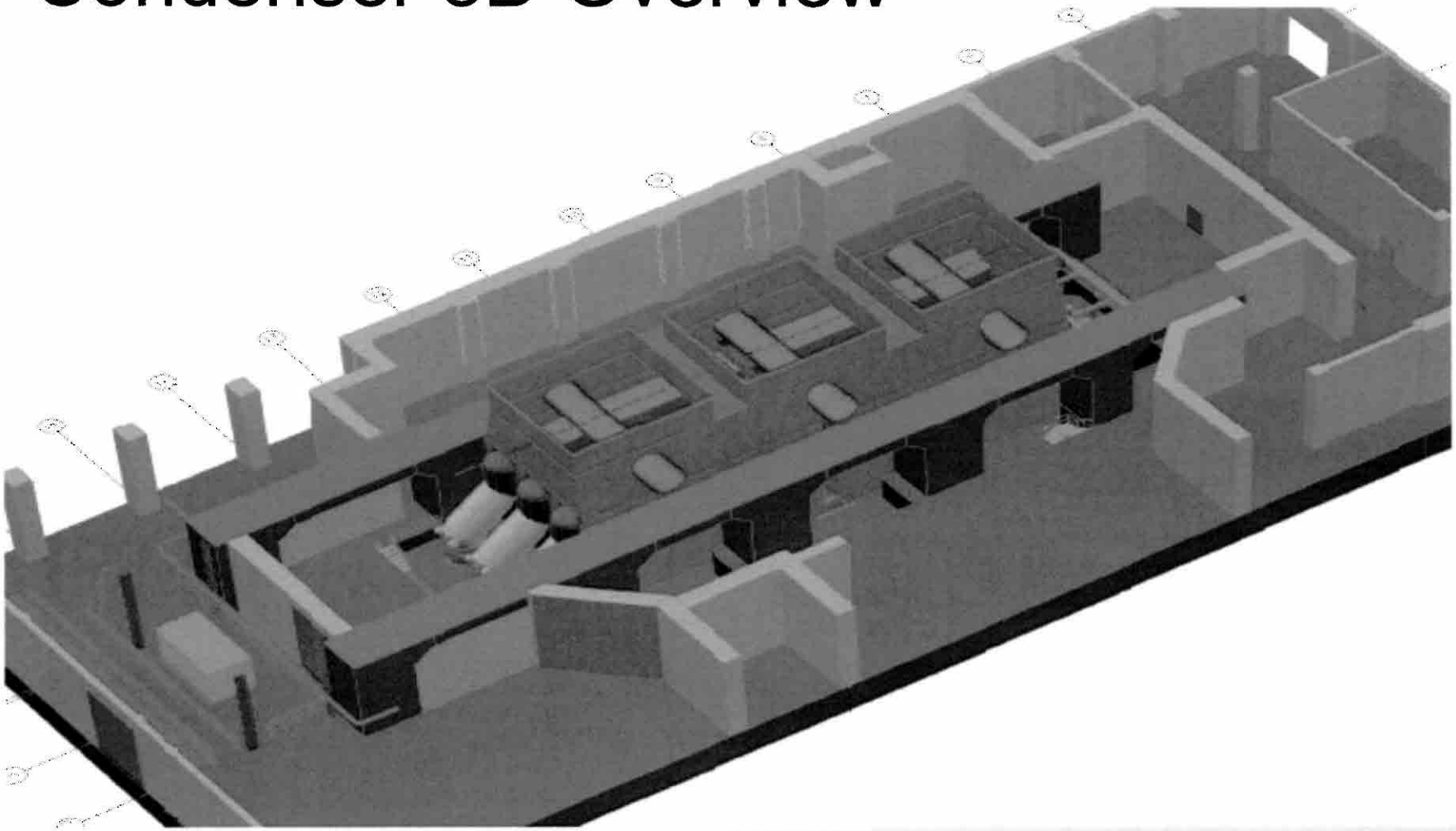
Help/Decisions Needed

- Senior Management to verbalize station commitment of Project to all Station personnel
- East Side Security Access – Ingress/Egress to Protected Area
- Fabrication Facility for Installation Contractor
- Relocation of the Relief Valve Testing Equipment Scope
- Expediting Procurement process of obtaining Installation contractor
- EN staffing needs for the Condenser Team & filling vacancies
- FY09 Funding Revisions – direction on how to ease budget issues
  - Vulnerable until Module & Installation Contractor Contracts placed
  - 06-03-08 FY09 Baseline due right during scheduling tool change
- Financial Incentives for Core Team members for duration of Project
- Electrical Engineering Augmentation Resources

What does success look like

- No condenser leaks during operating cycle 21.
- No unplanned power changes, forced losses, or plant shutdowns in operating cycle 21 attributable to condenser replacement project work.
- At least 80% of the projected increase in electrical output is achieved as demonstrated through performance testing.
- Condenser replacement completed on or ahead of schedule as baselined after supplier and installer selection (date to be specified by the Condenser Steering Committee).
- Condenser replacement completed at or under budget as baselined after supplier and installer selection (date to be specified by the Condenser Steering Committee).
- Condenser replacement completed at or under dose budget as baselined after supplier and installer selection (date to be specified by the Condenser Steering Committee).
- No significant (XX scfm) increase in Off-Gas flow rate attributable to the condenser replacement project.
- EMS ???
- No lost time injuries attributable to project work.
- One or fewer recordable injuries attributable to project work

Condenser 3D Overview



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Open Discussion & Action Summary

- Open Discussion
- Review Actions
- Closing Comments

ENERGY NORTHWEST

Condenser Replacement Project Steering Committee Meeting

Project No. 00608601

July 27, 2008

Brian Berglin

Agenda

Safety	5 min
Information items	10 min
Steering Committee Charter	15 min
R-19 Status	20 min
Break	5 min
Procurement Status	10 min
Other Projects affected	10 min
Staffing Plan	10 min
Round Table	20 min
Review Action Items	10 min
Meeting Effectiveness	5 min

Project Information Updates

- 30% Design Review for R-19 Condenser Travel Path Interference inside TGB (PDC 6693) completed. On track to complete 70% review.
- 30% Design Review for R-19 Condenser Mods to support rail system support & access (PDC 6834) completed On track to complete 70% review.
- FY08 Project cost are 13.6K under budget of $4010K. (.34% under spent)
- ½ of Building 80 being modified for Installation Contractor fabrication shop ready to begin work → old warehouse #5.
- Source Evaluation Panel Evaluation Criteria weighting completed for both contracts
- Five Studies in final stages to complete Interference removal Design Change (PDC 6693) Scope of Work
  - Expand West Turbine Building wall opening for more efficient ingress/egress
  - Condenser Bay Alternate Radiation Shielding Walls
  - HWC H2 & Air Injection skid panel re-location
  - Stator Water Cooling Skid removal method
  - Fire Protection piping re-location (east wall removal support)

Steering Committee Charter

What it is (Purpose):

- The Columbia Generating Station Condenser Project Steering Committee is established to provide oversight and direction through proactive performance monitoring of the approved scope, schedule and budget for the Project, as set forth in the Steering Committee Charter. The Committee is also established to provide a forum for the resolution of project related disputes/conflict, to the extent agreed by the members.

What it isn't:

- Project problem solver
- Troubleshooting group
- In the trench decisions

R-19 Status

see update on 7/28/08

Condenser Module Replacement - Rev 8 | Near Term Lookahead | 24-Jul-08 16:51

Activity Name	% Complete	Start	Finish
Outage Milestones	0%	26-Dec-08 13:00	24-Apr-09 13:00
Issue Major/Minor Design Changes	0%		26-Dec-08 13:00*
Work Order Planning Complete	0%		12-Feb-09 15:00*
Approved Ready for Walkdown (Status 30)	0%		16-Apr-09 10:00*
Work Package Ready to Work (Status 45)	0%		24-Apr-09 13:00*
Studies	0%	31-Jul-08 15:00	31-Jul-08 15:00
Expanded West Turbine Building Wall Opening	0%		31-Jul-08 15:00
Alternate Shielding for Wall Opening During Cycle 20	0%		31-Jul-08 15:00
H2 and Air Injection Skid Relocation	0%		31-Jul-08 15:00
Relocation of Stator Cooling Water Skid	0%		31-Jul-08 15:00
Fire Protection Piping Re-Location	0%		31-Jul-08 15:00
Decisions	0%	18-Aug-08 14:00	18-Aug-08 14:00
Expanded West Turbine Building Wall Opening	0%		18-Aug-08 14:00
Alternate Shielding for Wall Opening During Cycle 20	0%		18-Aug-08 14:00
H2 and Air Injection Skid Relocation	0%		18-Aug-08 14:00
Relocation of Stator Cooling Water Skid	0%		18-Aug-08 14:00
Fire Protection Piping Re-Location	0%		18-Aug-08 14:00
R19 Cond Replacement Travel Path Interferences (Inside TGB) EC 6693	0%	01-Jul-08 07:00 A	10-Dec-08 09:00
S&L 70% Package Development	1.12%	01-Jul-08 07:00 A	14-Oct-08 09:00
S&L Comment Incorporation for 100%	0%	03-Nov-08 09:00	06-Nov-08 09:00
100% Package Submitted by S&L for Approval	0%	06-Nov-08 09:00	07-Nov-08 09:00
PGM Approval (EC 6693)	0%		10-Dec-08 09:00
R19 Cond Mods to Support Rail System Support and Access EC 6834	0%	01-Jul-08 07:00 A	05-Nov-08 12:41
S&L 70% Package Development	3.62%	01-Jul-08 07:00 A	02-Sep-08 11:41
S&L Comment Incorporation for 100%	0%	25-Sep-08 11:41	02-Oct-08 11:41
100% Package Submitted by S&L for Approval	0%	02-Oct-08 11:41	03-Oct-08 11:41
PGM Approval (6834)	0%		05-Nov-08 12:41
Cond Travel Path Evaluation (Outside TGB) AR 6086 AS-7	0%	28-Jul-08 07:00	04-Sep-08 15:00
AR Assignment Response Prepared and Issued For EN Review	0%	28-Jul-08 07:00	14-Aug-08 15:00
EN Review of AR Response	0%	15-Aug-08 07:00	28-Aug-08 15:00
Comment Incorporation and Completed in PP - AR 6086 Assignment 07	0%	29-Aug-08 07:00	04-Sep-08 15:00
R19 Cond Perf. Monitoring Instrumentation EC 6992	0%	28-Jul-08 13:00	26-Dec-08 13:00
WEC 30% Package Development	0%	28-Jul-08 13:00	12-Sep-08 13:00
WEC 70% Package Development	0%	29-Sep-08 13:00	27-Oct-08 13:00
WEC Comment Incorporation for 100%	0%	18-Nov-08 13:00	28-Nov-08 13:00
100% Package Submitted by WEC for Approval	0%	28-Nov-08 13:00	02-Dec-08 13:00
PGM Approval (EC 6992)	0%		26-Dec-08 13:00
Procurement - installation Contractor	0%	07-Aug-08 07:00	31-Oct-08 15:00
Proposals Due	0%	07-Aug-08 07:00	07-Aug-08 15:00
Issue Request for BAFO	0%	25-Sep-08 07:00	25-Sep-08 15:00
Issue Contract	0%		31-Oct-08 15:00
Procurement - Modules	0%	02-Jul-08 07:00	28-Nov-08 15:00
Proposals Due	0%	02-Jul-08 07:00	07-Aug-08 15:00
Issue Request for Best and Final Offer (BAFO)	0%	30-Sep-08 07:00	30-Sep-08 15:00
Award Contract	0%		28-Nov-08 15:00
Work Package	0%	01-Jul-08 07:00 A	24-Apr-09 13:00
Work Order Preparation	5%	01-Jul-08 07:00 A	13-Feb-09 12:00
Work Order Review (Status 25)	2%	01-Jul-08 07:00 A	13-Mar-09 13:00
Work Order Team at Status 30 (Walkdowns)	2%	01-Jul-08 07:00 A	16-Apr-09 10:00
Work Order Team at Status 45 (Ready to Work)	2%	01-Jul-08 07:00 A	24-Apr-09 13:00

Actual Work | Critical Remaining ... | Remaining Work | Milestone

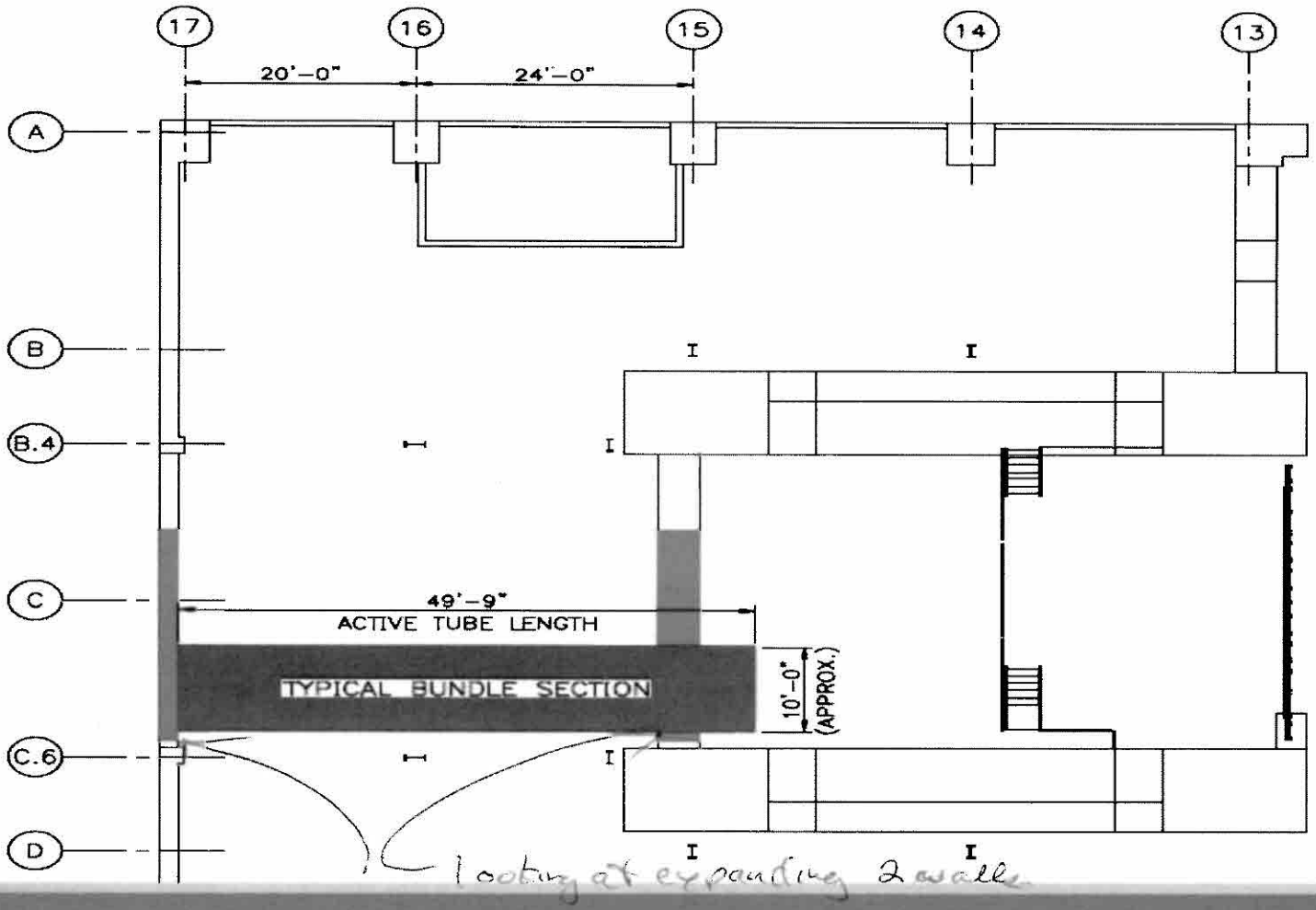
Page 1 of 1

ENERGY NORTHWEST

R-19 Status Continued

- Performance Monitoring Instrumentation scope refinement
  - 25 instruments originally
  - 45 instruments & 5 hubs
- ½ of Building 80 refurb cost is $286K
- Fast Track Project Outage Milestones reviewed by QA resulting in a "SAT" grade

Condenser bundle removal



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Contract Procurement Status

BPA mtg 8/12/08 S.O. 8/26/08 S.W.

Activity	Estimated Dates	
	Module	Installer
Issue Request of Proposal	Complete	Complete
Pre-bid Conference	Complete	Complete
Proposals Due	**08-06-08**	**08-06-08**
Visit Vendors (TBD)	**09-10-08**	
Offeror's Presentations		**08-18-08**
Best & Final Offer	**10-08-08**	09-30-08
Issue Limited Notice to Proceed	**10-24-08**	**10-16-08**
Contract Execution	11-25-08	10-30-08

Module Scope -12 Modules w/ requested delivery in 07-2010

Installer Scope - R-19 Implementation, R-20 Pre-outage Design & Install, R-20 Implementation. Mobilization 11-30-08 following Contract Execution.

Will take to Board in Oct.

ENERGY NORTHWEST

Other Project affected by Condenser

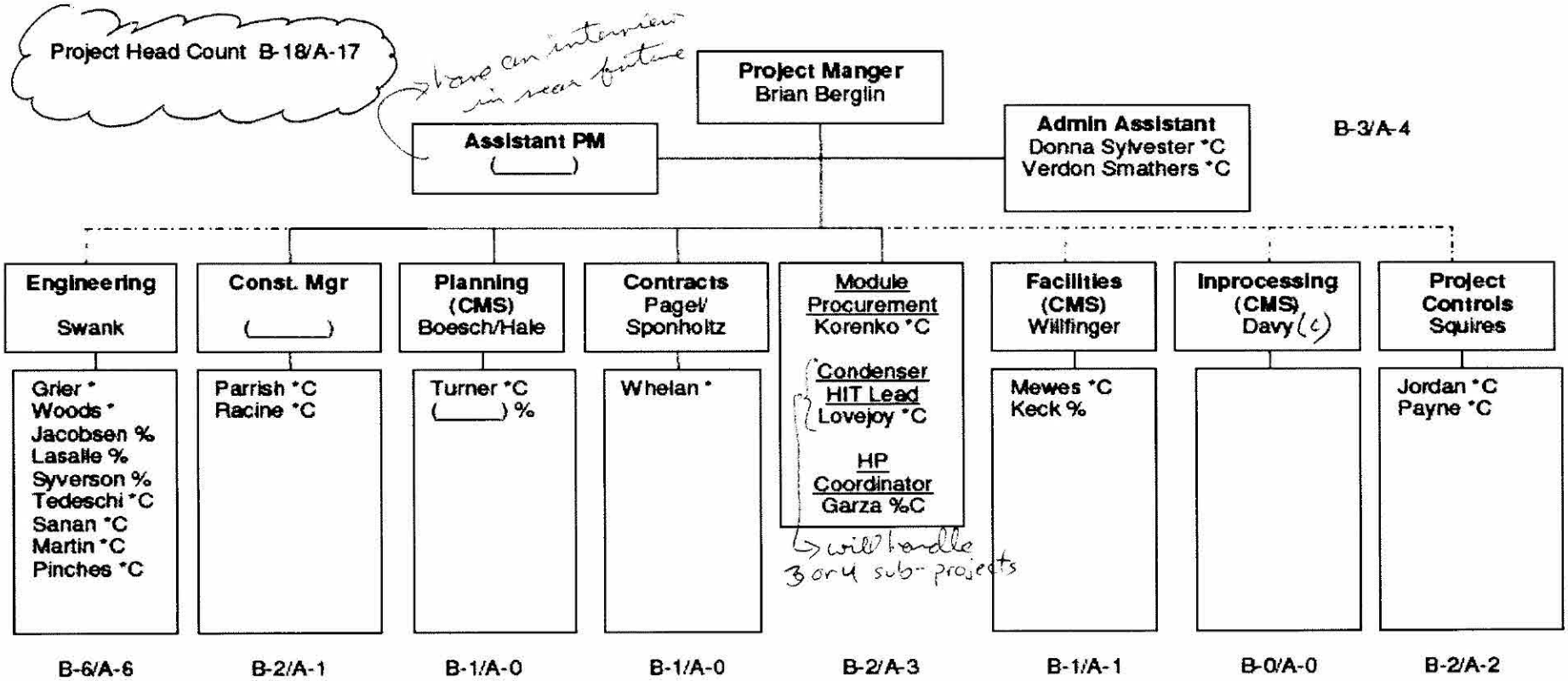
- Temporary Power Project
  - Added 3 Temporary Load Centers in TGB — Due to Condenser Project
  - Additional funding needed to support theTemporary Power Project was approved by PHC for $230K on 07-17-08. — came from Temp. Power budget.
- MOV Valve Refurbishment Area Re-location
  - MOV refurbish area in west end of Condenser Bay must be removed in R-19 — they already cut their budget by $1.0m
  - Funding of $150K submitted by MOV Project . PM checking to see if funding is still available in project. — in process
- Relief Valve Testing Area Re-location
  - Delayed until pre-outage R-20
  - Re-locating two water test stands to a temporary area — can do on line if shield wall gets put up.
  - Least cost option is estimated at $320K — will do shielding in R-19.
  - Funded by Condenser Project

They may choose to relocate permanently, funds come up w/ extra $

ENERGY NORTHWEST

Project Staffing Plan

Main Condenser Replacement Project



B - Before Installation Contractor
A - After Installation Contractor
* Full Time
% As Needed
C Contract
(_) TBD

Brian; "On the road to success now. Feel better about staffing now."

A good number of the contracts have worked at EN before and have a lot of experience of how to get things done.

ENERGY NORTHWEST

FY08 Cost Vs. Budget

Description	ENL ($K)	NENL ($K)	TOTAL ($K)
FY08 Budget	200.0	3,810.0	4,010.0
FY08 Spent	501.4	3,495.0	3,996.4
Delta	-301.4	315.0	13.6

FY09 Cost Vs. Budget

have backed out all "900" charges. – overhead of EN people

Description	ENL ($K)	NENL ($K)	TOTAL ($K)
Budget #	767.9	15714	16481.8
Spent	TBD	TBD	145
Spent & Committed	TBD	TBD	TBD

some question about the total, how you deal with how you report the costs.

burdened vs unburdened rate

ENERGY NORTHWEST

Business Case & LRP Budget

Input for HURON on 02-01-08 for CGS Condenser Project Business Case						
	Modular Titanium FY08$K					
Description	2008	2009	2010	2011	2012	Total
Procurement						
Procurement of Condenser	$ -	$ 18,000	$ 19,000	$ 2,060	$ -	$ 39,060
Installation						$ -
Internal Labor	$ 650	$ 1,000	$ 800	$ 1,400	$ 200	$ 4,050
External Labor	$ 300	$ 8,200	$ 2,600	$ 17,000		$ 28,100
Design and Project Support						$ -
Security Mods	$ 238	$ 1,917	$ 1,300	$ 1,550	$ -	$ 5,005
Design Packages	$ 2,820	$ 2,200	$ 726	$ 1,880	$ -	$ 7,626
Facilities	$ -	$ 1,250	$ 1,000	$ 1,000	$ -	$ 3,250
In-Processing		$ 1,000		$ 2,250	$ -	$ 3,250
Project Closeout						$ -
Decon/Disposal	$ -	$ -	$ -	$ -	$ 7,000	$ 7,000
Demob and Closeout	$ -	$ -	$ -	$ 757	$ 247	$ 1,004
Taxes						$ -
Washington State	$ 302	$ 2,931	$ 2,216	$ 2,385	$ 652	$ 8,487
Total	$4,310	$ 36,498	$ 27,642	$ 30,282	$ 8,099	$ 106,832
Current Budget	$4,010	$ 17,000				$ 106,832
Management Contingency		$ 8,000				

maybe in 2011 now

ENERGY NORTHWEST

Round Table

- Open Discussion
- Summarize Actions
- Closing Comments
- Meeting Effectiveness

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

FREEDOM OF INFORMATION ACT/PRIVACY PROGRAM

October 3, 2014

In reply refer to: BPA-2013-01716-F

Paul Koberstein
Cascadia Times
4037 N. Overlook Terrace
Portland, OR 97227

Mr. Koberstein:

This is a final response to your request for records that you made to the Bonneville Power Administration (BPA) under the Freedom of Information Act (FOIA), 5 U.S.C. 552. Your request was received on September 19, 2013, and was acknowledged in a letter dated September 24, 2013.

BPA made two partial releases of records, one on December 13, 2013, and a second on May 19, 2014. In a letter dated June 26, 2014, we estimated the delivery date of September 30, 2014, for the remaining eight documents.

You requested:
"All documents related to the Columbia Generating Station (CGS) condenser that are dated 2000 to 2013."

Response:
BPA is releasing one four-page draft letter in its entirety. The final version of this letter was released to you on December 13, 2013.

In this case, we assert Exemption 5 to protect the working documents (20 pages) of the BPA Manager of Contract Generating Resources. The manager created these records to help in the assessment of agency decisions regarding the CGS condenser.

Exemption 5 protects "inter-agency or intra-agency memorandums or letters which would not be available by law to a party other than an agency in litigation with the agency" (5 U.S.C. § 552(b)(5)). Exemption 5 protects the decision-making or deliberative process of government agencies. Records protected must be: (1) pre-decisional – created before the adoption of an agency policy or course of action; and (2) deliberative – making recommendations or expressing opinions on a legal or policy matter.

BPA attempted to segregate and release factual material from these redacted documents. It did not do so because the facts included were chosen by the Manager to make his recommendations, and wee therefore an integral part of the deliberative process.

We considered discretionary release of the redacted records in accordance with the guidelines set forth in Attorney General Holder's March 19, 2009, FOIA Memorandum. Agencies may decline to discretionarily release material when they reasonably foresee that disclosure would harm an interest protected by the statutory exemption. The deliberative process privilege protects the decision-making processes of government agencies, and Exemption 5 encourages open, frank discussions on matters of policy and protects against public confusion and the premature disclosure of proposed policies. Disclosure of the protected draft material and internal discussions would have a chilling effect on future BPA discussions and decisions, and we decline to discretionarily release this material.

Appeal:
Pursuant to Department of Energy FOIA regulations at 10 C.F.R. § 1004.8, you may administratively appeal this response in writing within 30 calendar days. If you choose to appeal, please include the following:

(1) The nature of your appeal: denial of records, partial denial of records, adequacy of search, or denial of fee waiver;
(2) Any legal authorities relied upon to support the appeal; and
(3) A copy of the determination letter.

Clearly mark both your letter and envelope with the words "FOIA Appeal," and direct it to the following address:

Director, Office of Hearings and Appeals
Department of Energy
1000 Independence Avenue SW
Washington DC 20585-1615

Please contact Kim Winn, FOIA Public Liaison, at 503-230-5273 or via email at kswinn@bpa.gov with any questions about this letter.

Sincerely,

C. M. Frost
Freedom of Information/Privacy Act Officer

Enclosure:
Responsive documents

Department of Energy

Bonneville Power Administration
Mail Drop 1399
P.O. Box 968
Richland, Washington 99352-0968

POWER SERVICES

March 15,~~February xx,~~ 2007

In reply refer to: PGC/Richland

Mr. W. S. Oxenford, Vice President
Technical Services
Energy Northwest M/D PE04
P.O. Box 968
Richland, WA 99352-0968

Dear Mr. Oxenford:

BPA understands that Energy Northwest has decided to replace the Columbia Generating Station main condenser in FY 2009 using a re-tube with titanium tubes approach. The options considered included use of various tube material, and whether to re-tube or use modular replacement methodology. This project represents a large capital and expense impact on BPA and the region, and the condenser replacement effort itself will require an extended outage beyond the normal refueling outage length. The option that EN has selected currently requires approximately 33 additional outage days to a planned refueling and maintenance outage without condenser replacement. The cost of an additional 33 days of outage is approximately $35 million. This expense cost (not capital) will have an immediate impact on our rates that was not planned for in this 2007-2009 rate case.

BPA acknowledges EN's review of the options identified by Sargent & Lundy in their study and of the cost benefit analysis developed for those options. We would like to ensure we have clarity and a common understanding of the facts and options considered when EN reached its recommendation. With that in mind, we request that you respond to our questions below to enable us to finalize our position and take action on the condenser project, which we anticipate would occur in the course of our action regarding the FY 2008 CGS budget.

In addition, we believe that the results of the fuel inspection and condenser eddy current testing effort, both of which are scheduled to be performed during the R-18 outage (May 2007), will provide key information regarding the need for the condenser replacement at this time. Although we would agree that the present EN recommended course of action has its merits, and falls within the broad concept of "prudent utility practice", we would like ~~to access~~ the following information to inform a collaborative discussion with you regarding whether there are timing options~~paths~~ to condenser replacement that assure high plant reliability/integrity/safety, but are more cost effective for our regional rate payers. We would like to have this discussion prior to our action on the EN FY 2008 budget.

1. What is the estimated end-of-life (using the HEI methodology) for the current condenser assuming continued proper maintenance? Given the 40-yr design life of the existing condenser, and the full eddy current testing scheduled during refueling outage R-18, would these results (as well as the R-18 fuel inspection results) provide valuable information that either would affirm the current recommendation or indicate that the timing of the condenser replacement could be re-evaluated?~~additional alternatives could be considered?~~

2. What are the projected costs for continuing regular refueling outage maintenance on the existing condenser, and a new condenser?

3. What is the estimated life of the new condenser, including a comparison with industry experience that supports the estimate? What is the degree of confidence the new condenser will last to the end of plant life in 2043, assuming license extension is implemented?

4. What is the expected plant energy loss due to condenser driven de-rates during summer months with a new re-tubed titanium condenser?

5. Based on industry experience, what is the projected number of tubes that will require plugging for the new condenser through end of plant life, assuming license extension is implemented, and the corresponding annual energy losses expected due to condenser driven de-rates? What is the likelihood and number of infant mortality tube failure in the new condenser?

6. What is the ability of the new condenser design to support future power up-rates, if up-rates are implemented? What are the other plant equipment upgrades and associated costs that could be implemented to mitigate power de-rates from an up-rated power level condition?

7. Please provide a summary of the number and cycle of occurrence, of condenser tube failures at CGS separated into the following causal categories: debris induced failures~~FME~~, steam impingement, vibration induced, general erosion, and any other.

8. Describe the actions taken to address the root cause of foreign material exclusion (FME) problems documented in PER No. 204-0811, and how these actions are expected to prevent re-occurrence of foreign material caused leaks in the new condenser.

9. Please provide a summary of the number and cycle of occurrence, of fuel failures at CGS separated into the following causal categories: foreign material induced fuel fretting, copper interaction with fuel cladding, condenser leakage (feedwater contaminants), and others.

10. Please provide the projected number of fuel failures between now and end of life of the current condenser separated into the following categories: foreign material induced fuel fretting, copper interaction with fuel cladding, condenser leakage (feedwater contaminants), and others. Also, provide the projected number of fuel failures expected during the lifetime of the new condenser separated into the same categories.

11. What are the estimated levels of feedwater copper before and after condenser tube material replacement? Will the copper levels after tube replacement meet all industry guidelines?

12. What is the estimated dose reduction relative to the collective radiation exposure (CRE) performance indicator, separated into the following categories: dose reduction due to condenser tube material replacement, dose reduction associated with chemical decontamination during refueling outages, dose reduction associated with the cobalt reduction effort, and dose reduction associated with fewer tube leak repairs? What is the estimated CRE performance indicator in two years if the condenser is not replaced and the cobalt reduction efforts proceed and chemical decontaminations are conducted as part of future refueling outages?

13~~1~~. Describe Energy Northwest's enhanced ability to detect and repair condenser tube leaks and confirm whether this is included in the cost benefit analysis business case.

14. What is the total cost estimate to replace the condenser with the option EN has chosen, excluding the cost of replacement power? Based on the past history of cost increases in major plant projects, including ISFSI, HWC, DEH, and FWH replacement, provide the~~a~~ degree of confidence associated with this cost estimate.

15. Please provide a copy of the cost benefit analysis business case for the condenser replacement. We would appreciate it if you would include a summary explanation of the assumptions that were used and verified in the analysis.

16. Given a net present value of negative $65 million for the chosen replacement option, please describe the offsetting factors, i.e., regulatory commitments, INPO recommendations, etc., that make this a viable project from a cost benefit perspective. Are there any other alternative options that result in a less negative, zero, or positive net present value?

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Thank you for addressing these important questions. If you have any questions about the list above, please contact Phil Smith at 5130 or me at 5752.

Sincerely,

Andrew J. Rapacz, Manager
Contract Generating Resources

Cc:
Dale Atkinson
Vic Parrish

bcc:
S.R. Oliver
P.E. Smith
Official File – PGC (ERMS PM-14-23 Columbia) (AM 1003 Turbine Maintenance C 320975)
http://bpaweb/services/erms/PM/14/23a/PGC%20Records/Forms/AllItems.aspx

Reviewed: _____
PES/date

DRAFT

BPA Perspective/Questions regarding Main Condenser

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DRAFT

(b)(5) [redacted]

(b)(5)

(b)(5)

[redacted]

DRAFT

(b)(5)

Deep Bed Demineralizers/Retube with Copper

(b)(5)

(b)(5)

MAIN CONDENSER

(b)(5)

DRAFT

Dear Ted,

I would like to thank you once again for the success we have achieved as partners in continuing the Debt Optimization Program, achieving debt extension and implementing the direct payment agreements. Each of these successes is playing an important role in keeping BPA's rates down for the northwest's ratepayers. I am also appreciative for Energy Northwest's participation in the Power Function Review process. This process has provided budget transparency to our customers and provided them with an opportunity to ask questions.

I would like to take this opportunity to discuss Executive Board Resolution No. 1445, the performance of the main condenser at Columbia, clarify Bonneville's position regarding license renewal and lastly, provide my thoughts on our business relationship.

Resolution 1445:
The Energy Northwest Executive Board recently passed Resolution No. 1445 regarding equipment reliability. The resolution notes Bonneville's potential influence, through budget uncertainty, over what the Board believes are nuclear reliability and safety issues. In addition, the resolution states, in part, that the Board insists all parties keep commitments on plant life extension investments as well as the extension of debt and replacement of the condenser.

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We are looking forward to working with you as partners as we jointly seek to improve Cloumbia's reliability.

Sincerely,

Steve Wright

From: Smith,Phil (BPA) - PGC-RICHLAND
Sent: Thursday, July 06, 2006 11:31 AM
To: Rapacz,Andy (BPA) - PGC-RICHLAND; Bentrup,Paul E (BPA) - PGC-RICHLAND; Smith,Phil (BPA) - PGC-RICHLAND
Subject: CONDENSER WHITE PAPER IMPROVEMENTS

(b)(5)

[redacted]

(b)(5)

[redacted]

CONDENSER WHITE PAPER COMMENTS

(b)(5)

(b)(5)

BPA comments on EN's responses to questions concerning main condenser replacement

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